IN THE MATTER OF the *Electrical Power Control Act,* R.S.N.L. 1994, Chapter E-5.1 (the *EPCA*) and the *Public Utilities Act*, R.S.N.L. 1990, Chapter P-47 (the *Act*), and regulations thereunder;

AND IN THE MATTER OF an Application by Newfoundland and Labrador Hydro (Hydro) pursuant to Subsection 41(3) of the *Act*, for approval of the procurement and installation of a combustion turbine at Holyrood.

TO: The Board of Commissioners of Public Utilities (the Board)

THE APPLICATION OF NEWFOUNDLAND AND LABRADOR HYDRO (Hydro) STATES THAT:

1. Hydro is a corporation continued and existing under the *Hydro Corporation Act, 2007*, is a public utility within the meaning of the Act and is subject to the provisions of the *Electrical Power Control Act, 1994.*

2. Hydro owns and operates 1507.5 MW of generating capacity on the Island Interconnected System. In deciding when to add a generation source Hydro uses a Loss of Load Hours (LOLH) criterion which is a means of assessing the likelihood that Hydro will be unable to meet its customer load due to a generation capacity shortfall. Hydro has been using a LOLH standard of 2.8 hours/year in its generation capacity analysis whereby if in the analysis the 2.8 hours is exceeded, it would identify a requirement for additional capacity.

3. The LOLH criterion Hydro uses is based upon expert advice it has received supplemented by its experience. Adding generation sources in advance of their demonstrated need is costly for the ratepayer; adding generation sources later than their demonstrated need can cause an inability to meet customer loads to a greater extent than is considered reasonable and adequate.

5. The LOLH for Hydro's Island Interconnected System generation capacity reliability is forecast to exceed 2.8 hours in 2015. For that reason, Hydro has been planning to install 60 MW of additional generation on its system in late 2015 in the form of a combustion turbine as outlined in its Generation planning Issues Report of 2012.

6. Hydro has completed an assessment for the location of the combustion turbine and has determined that the Holyrood Generating Station site is the most appropriate.

7. Due to its experiences in January 2014, Hydro has revisited its LOLH guideline and has run sensitivity analyses with additional customer electrical loads and higher than expected forced outage rates at its generating stations. Those analyses indicate that it would be prudent, if practicable, to advance the installation of the combustion turbine and to increase the generating capacity of the combustion turbine it installs.

8. In investigating the available combustion turbine opportunities, Hydro has learned that there are options available to procure and install existing (i.e. already built) combustion turbines of a larger capacity, at an earlier timeframe than originally planned, and at approximately the same cost that was earlier estimated for a 60 MW turbine. That is, Hydro has learned that suppliers can provide combustion turbines in the 100 MW range and have them installed and commissioned at the Holyrood site within eight months of making the commitment.

9. Given the reliability benefits that would be achievable by having a combustion turbine of approximately 100 MW installed at Holyrood to be in-service for the 2014-2015 winter, Hydro is applying for approval for a capital project for this generation addition.

10. Therefore, Hydro makes Application that the Board make an Order approving, pursuant to Subsection 41(3) of the *Act*, the capital expenditure of $119,000,000 for the purchase and installation of a 100 MW (nominal) combustion turbine to be installed at Holyrood as set out in this Application and in the attached project description and justification document.

11. The Applicant submits that the proposed capital works and expenditures are necessary to ensure that its generation system can continue to provide service

which is reasonable safe and adequate and just and reasonable as required by Section 37 of the *Act*.

DATED at St. John's, in the Province of Newfoundland and Labrador, this 10th day of April, 2014.

Geoffrey P. Young
Counsel for the Applicant
Newfoundland and Labrador Hydro
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Facsimile: (709) 737-1782

IN THE MATTER OF the *Electrical Power Control Act,* R.S.N.L. 1994, Chapter E-5.1 (the *EPCA*) and the *Public Utilities Act*, R.S.N.L. 1990, Chapter P-47 (the *Act*), and regulations thereunder;

AND IN THE MATTER OF an Application by Newfoundland and Labrador Hydro (Hydro) pursuant to Subsection 41(3) of the *Act*, for approval of the procurement and installation of a combustion turbine at Holyrood.

TO: The Board of Commissioners of Public Utilities (the Board)

I, Robert J. Henderson, Professional Engineer, of St. John's in the Province of Newfoundland and Labrador, make oath and say as follows:

1. I am Vice-President of Newfoundland and Labrador Hydro, the Applicant named in the attached Application.

2. I have read and understand the foregoing Application.

3. I have personal knowledge of the facts contained therein, except where otherwise indicated, and they are true to the best of my knowledge, information and belief.

SWORN at St. John's in the)
Province of Newfoundland and)
Labrador this 10th day of)
April 2014, before me:)

Barrister – Newfoundland and Labrador

Robert J. Henderson

A REPORT TO

THE BOARD OF COMMISSIONERS OF PUBLIC UTILITIES

Documented to be Sealed and Signed by Preparer or Preparer's Supervisor	Electrical
	Mechanical
	Civil
	Protection & Control
	Transmission & Distribution
	Telecontrol
	System Planning

Supply and Install 100 MW (Nominal) of Combustion Turbine Generation

Holyrood

April 10, 2014

newfoundland labrador hydro

a nalcor energy company

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Appendices

Executive Summary

This report provides the Board of Commissioners of Public Utilities (the Board) with information to support the proposed installation of a 100 MW (nominal[1]) combustion turbine (CT) and balance of plant (BOP) at the Holyrood Generating Station location to be in service late in 2014. The proposed addition is intended to fulfil three main functions:

1. Additional long term generation capacity for the Island Interconnected System;
2. Additional generation capacity on the Avalon Peninsula to mitigate local generation supply and transmission contingencies; and
3. Replacement of the leased black start diesel facility at the Holyrood Generating Station.

The Island Interconnected System has a requirement for additional generation capacity in 2015 to meet established generation reliability criteria. System Planning's *Generation Planning Issues - November 2012* report (see Appendix C) submitted to the Board in December 2012 identified a generation capacity deficit through a violation of the generation capacity reliability criteria[2] in 2015 that will continue until 2018 when the Island Interconnected System is interconnected with the North America grid. Please see Table 1 below:

Table 1: Island System Loss of Load Hours (LOLH)

2013- 2020

2013	2014	2015	2016	2017	2018	2019	2020
0.97	2.48	3.85	5.10	4.98	0.15	0.16	0.16

[1] Nominal is intended to allow flexibility of vendors to proposed combustion turbine(s) that can vary somewhat from a fixed 100 MW. Vendors have specific units and this allows flexibility and the opportunity to select the best value.

[2] Capacity Reliability Criteria: The Island Interconnected System should have sufficient generating capacity to satisfy a Loss of Load Hours (LOLH) expectation target of not more than 2.8 hours per year.

This generation capacity deficit and the least cost long term options to rectify it were analyzed as part of the 2012 Muskrat Falls DG3 evaluation of the Isolated Island and Interconnected Island alternatives. The results of that evaluation were presented in the report *Review of the Muskrat Falls and Labrador Island HVdc Link and the Isolated Island Options – October 2012 – Manitoba Hydro International (see attached in Appendix D)*.

The analysis indicated that, based on available generation options, the least cost long term option to meet the additional capacity requirement in 2015 was a 50 MW (nominal) combustion turbine. A recent review of the customer demand forecast and generation availability assumptions confirmed this replacement with a 60 MW (nominal).

Transmission Reliability Considerations

The completion of the Muskrat Falls Project and high voltage direct current (HVdc) interconnections between Labrador and the island, and the island and Nova Scotia, in 2017 will permanently alter the electrical system landscape on the Island of Newfoundland. The island will no longer be isolated and, with two interconnections to the North American electrical system, the options available to ensure and enhance power system generation supply reliability will expand significantly. While the electrical landscape of the Island Interconnected System will change significantly post 2017, any generation capacity added to secure system reliability prior to the interconnections will continue to provide required system security for potential transmission contingencies long into the future. These transmission contingencies include:

1. Interruption of supply over the Labrador-Island HVdc Link due to single pole interruptions or in the unlikely event of bi-pole interruptions.
2. Interruption of supply over the 230 kV transmission lines into the Avalon Peninsula.
3. Single 230 kV transmission line outages which limit transfer capability.

Sensitivity Analysis

In late December 2013 and early January 2014, Hydro experienced unrelated generation de-ratings at five separate generating stations resulting in a total generation unavailability of 233 MW. The generation unavailability combined with very cold temperatures resulted in capacity shortfalls on both January 2 and January 3 requiring Newfoundland and Labrador Hydro (Hydro) and Newfoundland Power (NP) to initiate rotating customer outages to preserve system integrity.

As a result of this significant and unprecedented interruption to customer supply, Hydro initiated an independent review of its generation capacity planning processes. This was conducted by Ventyx, an ABB company, and its purpose was to determine whether Hydro's planning processes should have established a requirement for additional generation capacity prior to January 2014.[3] This review determined that the generation planning capacity processes followed accepted practices and that the installed generation capacity on the Island Interconnected system met established reliability criteria.[4] The review, however, did result in recommendations that generation capacity addition analysis include enhanced sensitivity analysis on generating unit reliability performance and increased customer demand.

Based on the recommendations of Ventyx, Hydro expanded its 2013 Base Case analysis to include sensitivities to show the impact on capacity supply reliability with:

1. reduced thermal generation availability;

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[3] The Ventyx report was filed by Hydro in Volume 2, Schedule 4, Appendix 1 of Hydro's Interim Report to the Board, "A review of Supply Disruptions and Rotating Outages: January 2-8" filed on March 24, 2014, entitled "2014 Newfoundland and Labrador Hydro Planning Review Process Review" by Ventyx, March 21, 2014 and is attached as Appendix 'E'.

[4] With respect to load forecasting, Ventyx concluded "[t]he methodology used by NP and HYDRO are consistent with accepted utility practices", page 12 of Appendix 1 of the above report, Appendix 'E'. With respect to generation planning reserve criteria they concluded that "NLH's generation planning reserve criterion of 2.8 Hours per year is prudent and consistent with standard utility practices", page 23 of the above report.

2. load forecast based on extreme weather; and
3. a combination of reduced availability and extreme load forecast.

As an input to the generation planning process, Hydro uses specific indicators to represent the expected level of unavailability due to unforeseen circumstances: Derated Adjusted Forced Outage Rate (DAFOR) for the thermal units at Holyrood; and Utilization Forced Outage Rate (UFOP) for the combustion turbines at Hardwoods and Stephenville. The DAFOR and UFOP indicators used in the planning model are representative of a historic average of the actual performance of these units over the past five years. Ventyx, in its review determined this to be a reasonable assumption for long term planning. However, over the past two years in particular, the availability of some of the thermal units have been tracking lower than average and Ventyx recommended it prudent to conduct a sensitivity analysis on the outages to determine how reduced availability might impact reliability. Hydro conducted this sensitivity analysis and increased the thermal generation outage rate assumptions.

The load forecast Hydro uses in its utility planning is a weather normalized forecast which effectively means an average peak forecast or what is referred to as a P 50 forecast. Simply stated, the actual peak has a 50 per cent chance of being either higher or lower than that figure. When there is extreme wind and cold, the actual peak can exceed the normalized figure. With an extreme load sensitivity a P 90 load forecast was generated which assumes an extreme wind chill at the time of peak. With the P 90 load forecast there is 90 per cent probability of the actual peak being lower and conversely only a 10 per cent probability of it being higher.

Table 2 below summarizes the results of the sensitivity analysis.

Table 2: LOLH for Varying Load and Generation Availability Assumptions

Base Case Generation Additions	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
60 MW CT 2015	0.97	2.48	3.36[5]	2.34	2.34	0.15	0.16	0.16
60 MW Interruptible 2014	0.97	1.17	1.93	2.66	2.72	0.15	0.16	0.16
60 MW interruptible 2014 & 60 MW CT 2015	0.97	1.17	1.68	1.11	1.17	0.15	0.16	0.16
100 MW CT 2014	0.97	2.08	0.96	1.31	1.33	0.15	0.16	0.16
60 MW interruptible 2014 & 100 MW CT 2014	0.97	0.98	0.41	0.58	0.64	0.15	0.16	0.16
LOLH Criteria	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8
Base & Reduced Fossil Plant Reliability Generation Additions	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
60 MW interruptible 2014 & 60 MW CT 2015	0.97	1.96	1.52	2.12	2.18	0.15	0.16	0.16
100 MW CT 2014	0.97	3.63[5]	1.73	2.32	2.31	0.15	0.16	0.16
60 MW interruptible 2014 & 100 MW CT 2014	0.97	1.87	0.79	1.12	1.18	0.15	0.16	0.16
LOLH Criteria	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8
Base & Increased Demand	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
100 MW CT 2014	0.97	4.06[5]	2.03	2.69	2.60	0.15	0.16	0.16
60 MW interruptible 2014 & 100 MW CT 2014	0.97	2.00	0.92	1.26	1.28	0.15	0.16	0.16
Base & Increased Demand & Reduced Reliability	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
60 MW interruptible 2014 & 100 MW CT 2014	0.97	3.51[5]	1.67	2.24	2.23	0.15	0.16	0.16

The results of that analysis indicated that to meet the capacity supply reliability criteria

[5] This is above the criteria of 2.8 hours, however in the cases of additional CTs they are planned to be in service in December thus mitigating some of the exposure.

under the assessed sensitivities the following changes in scheduled in service and capacity size would be required.

1. Reduced thermal generation availability would require a 100 MW combustion turbine in service in December 2014 or a combination of 60 MW interruptible arrangements in service in December 2014 with a 60 MW combustion turbine installed in December 2015;
2. Load forecast based on extreme weather would require a 100 MW combustion turbine in service in December 2014; and
3. Combination of reduced availability and extreme load forecast would require a combination of a 100 MW combustion turbine and 60 MW interruptible arrangements with all in service in December 2014.

While 60 MW of interruptible is acceptable for the Base Case from a capacity planning perspective, it leaves little margin for increased load or reduced reliability before the HVdc interconnections are in service. Furthermore, it does not bring the transmission reliability benefits required.

Customer Demand Side Alternatives to a Combustion Turbine

Hydro considered the possibility of continuing with the 14 MW diesel plant at Holyrood along with interruptible and/or enhanced Conservation and Demand Management (CDM) programs targeted at demand reduction.

At over 60 MW, the amount of capacity achievable through industrial interruptible arrangements is significant. However, it would not provide the long term reliability requirements on its own. In particular, it does not provide a generation source on the Avalon Peninsula which can assist in transmission line contingencies and reduce transmission losses in the event of Avalon generation contingencies. Therefore, while industrial customer interruptible arrangements are important reliability enhancements which will complement the combustion turbine installation, they are not substitutes.

The current focus of CDM programs has been energy conservation as it is tied to reducing fuel use, primarily at Holyrood. While demand reduction programs are demonstrating successful implementation in other jurisdictions, they take time to be utilized by customers. Where successful in reducing demand, these programs are generally aided by financial programs that support retrofitting homes, and by a rate structure that motivates customers to invest in and change habits. While an enhanced CDM program can be beneficial it is not a viable option in the timeframe available to change consumer behavior and achieve savings. At this time, a CDM offering that includes demand reduction in addition to energy reduction is considered a complementary program to the installation of the combustion turbine. Over time, enhanced CDM programs will serve to better manage overall system demand. However in the short term, from now until December 2015, what is needed is a firm increase in generation, or an equivalently firm reduction in demand on the Avalon Peninsula, to obtain both transmission and system capacity benefits.

Conclusions and Recommendation

The generation capacity reliability criteria can be met using Base Case assumptions by either a 60 MW combustion turbine[6] or with 60 MW of interruptible load. While interruptible load may satisfy capacity reliability criteria, it does not provide the same immediate or long term benefits provided by a combustion turbine located at Holyrood. In the near term a combustion turbine located at Holyrood provides:

- Increased reliability and security for the Avalon Peninsula, particularly during generation and transmission line contingencies;
- The ability to reduce transmission line losses especially during contingency conditions; and

[6] While there is indication this is above the criteria of 2.8 hours for the initial year, the additional CT's are planned to be in service in December thus mitigating some of the exposure.

- The ability to return the leased black start diesels at Holyrood.

  In the longer term beyond 2017, the combustion turbine provides:

- Continued reliability and security for the Avalon Peninsula;
- On-island capacity to support existing island generation and imports from Nova Scotia in the low probability event of a bipole failure on the Labrador Island Link; and
- Additional generation to support reliable operation during the potential monopole operation as a result of a single pole outage on the Labrador Island Link.

The results of the sensitivity analysis demonstrate that the 60 MW additional capacity will be insufficient to meet the reliability criteria in 2015 under certain conditions. In order to provide a similar level of reliability under those conditions it would be beneficial to obtain additional capacity with an in service earlier than December 2015.

During the investigation of options for meeting the 60 MW combustion turbine requirement in 2015 and, while examining options for a more immediate generation addition during January of 2014, Hydro identified several combustion turbine options that, with expedited regulatory approval and contract award, could provide capacity up to 100 MW and in service late in 2014. An analysis with budgetary quotations from suppliers has determined that by going to the pre-owned but unused or aftermarket[7], a combustion turbine can be brought into service at Holyrood in late in 2014 within the $120.8M cost estimate of a new 60 MW combustion turbine with an in service of December 2015. Therefore, the least cost, reliable option could be a pre-owned but unused 100 MW combustion turbine plant installed at Holyrood in late 2014.

In order to successfully implement this option or a similarly expedited proposal, early approval is essential. To guard against potentially losing this opportunity, Hydro has issued a functional specification through a public tender with a close date of April 21, 2014 with the

[7] Aftermarket refers to equipment that was initially purchased or leased form a manufacturer for use but never installed.

subsequent award subject to the Board's approval of this application. The award date to secure such an expedited schedule is April 30, 2014. The tender process will be open to both new and ready built (but unused) combustion turbines thus encouraging original equipment manufacturers as well as aftermarket sources. All proposals must assure an in service date in 2014. Discussions have been held with several vendors and they are aware of the required 2014 in service date. However, to ensure this expedited schedule can be achieved a timely approval by the Board is essential.

The impact of the combustion turbine cost on customer rates has been included in rate projections by Hydro provided to the Board in its GRA submissions and in the Muskrat DG3 rate projections. Hydro estimates the combustion turbine may cause an approximate 2.3 per cent increase above existing rates. Hydro will be assessing the annual cost of the combustion turbine plant with its other costs and will make an appropriate application to the Board for approval for the recovery of these cost changes in its customers' rates.

In conclusion, Hydro recommends that, to meet the 2015 Island Interconnected System capacity requirement, approval be granted as soon as possible for a capital budget of $118.9M to acquire and install a 100 MW (nominal) combustion turbine plant and associated equipment at Holyrood in 2014.

As well, for added security in the event of higher demands, decreased reliability or for schedule slippage of the proposed combustion turbine proposed in service date, Hydro is proposing to negotiate interruptible contracts with major industrial customers at least for 2014-2015. Efforts will continue on CDM programs with an increased emphasis on demand reduction.

Hydro respectfully seeks expeditious and timely approval of this application so that it can expedite the delivery and installation of this procurement for 2014.

1 ABBREVIATIONS

AACE	Association for Advancement of Cost Engineering
CPW	Cumulative Present Worth
CT	Combustion Turbine or often referred to as a gas turbine
BOP	Balance of Plant and includes all other equipment necessary to complete the installation of major components such as turbines, generators transformers, etc.
DAFOR	Derated Adjusted Forced Outage Rate, used in Strategist as a reliability measure for steam and hydraulic units
EPC	Engineer, Procure and Construct
HVdc	High Voltage direct current
ISO	International Standards Organization
LIL	Labrador Island HVdc link
LOLH	Loss of Load Hours
MVAR	Megavolt Ampère Reactive
MIL	Maritime Link between Nova Scotia and the Island of Newfoundland
O&M	Operation and Maintenance
P&C	Protection and Control
P 50	A projection that the actual will be less that that figure 50% of the time
P 90	A projection that the actual will be less than that figure 90% of the time
RFP	Request for Proposals
UFOP	Utilization Forced outage rate, used in Strategist for reliability measure of combustion turbines.

2 GLOSSARY

Combustion Turbine (CT) - Also known as gas turbines. The fuel source for these devices is not necessarily gas and can vary from crude to natural. (Both terms are common in the industry and in Hydro's case, the fuel source is primarily #2 fuel oil). During the process, air is compressed, mixed with fuel and then ignited to produce a high volume of hot gas. This hot gas is directed to a power turbine which turns this energy into mechanical rotational force which is used to turn an electrical generator. There are two types, aero derivative and industrial. The aero derivative are turbine engines originally designed for aircraft applications that have been adapted for electric power production instead of propulsion. Industrial gas turbines are often used in industry to provide mechanical, electrical power and process heat. They are as well used by electric utilities for generation in a similar manner as aero-derivatives or a part of a combined cycle plant. They can as well be used in standby applications for peak load management or intermittent applications, with the start time similar but the ramp rate (time to 100 per cent loading) is a little longer.

Balance of Plant - The "balance of plant" of a system is made up of the components not included in the primary system itself. This includes blowers, compressors and pumps and other necessary but not primary components.

Black Start - A black start is the process of restoring a power station to operation without relying on the external electric power transmission network.

Normally, the electric power used within the plant is provided from the station's own generators and often referred to as unit service. In the case of a plant such as Holyrood, all major loads such as pumps and motors necessary to provide net output to the system by that unit is, after startup and a minimum loading, normally taken from the unit service system. If all of the plant's main generators are shut down, station service power is provided by drawing power from the grid through the plant's transmission line. However, during a wide-area outage, off-site power supply from the grid will not be available. In the absence of grid power, a so-called black start capability needs to be provided to allow starting the major generation so that it can provide power to the grid. For thermal plants, the amount of power required is considerable due to the high power motors required for air, water (both cooling and for the boilers), fuel, combustion air and so on. On a hydro unit, the power for starting is minimal and can be provided at times by battery systems, or a small diesel unit, or both. Some large CTs also may require a smaller diesel unit to black start the CT.

Derated Forced Outage Rate (DAFOR) - Is the ratio of equivalent forced outage time to the equivalent time plus the total equivalent operating time.

ISO Conditions - Gas turbine output and performance is specified at standard conditions called the ISO ratings. These are specified as per ISO standards 3977-2 (Gas Turbines - Procurement - Part 2: Standard Reference Conditions and Ratings). The three standard conditions specified in the ratings are Ambient Temperature - 15 degrees C, Relative Humidity - 60 per cent and Ambient Pressure at Sea Level.
(Source: http://www.brighthubengineering.com/power-plants/25425-what-is-iso-rating-of-gas-turbines/).

Least Cost - For Hydro, the outcome of the generation planning analysis is Cumulative Present Worth (CPW), which is the present value of all incremental utility capital and operating costs incurred by Hydro to reliably meet a specific load forecast given a prescribed set of reliability criteria. Where the cost of one alternative supply future for the grid has a lower CPW than another, the option with the lower CPW would normally be recommended by Hydro, consistent with the provision of mandated least cost electricity service.

Loss of Load Hours (LOLH) - Is a statistical assessment of the risk that the System will not be capable of serving the System's firm load for all hours of the year. For Hydro, an LOLH expectation target of not more than 2.8 hours per year represents the inability to serve all firm load for no more than 2.8 hours in a given year.

Reactive Power (MVARs) - Reactive power is the difference between working power (active power measured in kW) and total power consumed (apparent power measured in kVA). Some electrical equipment used in industrial and commercial buildings requires an amount of 'reactive power' in addition to 'active power' in order to work effectively. Reactive power therefore generates the magnetic fields which are essential for inductive electrical equipment to operate - especially transformers and motors.

Power Factor - Is the relationship between 'active' and 'reactive' power and indicates how effectively electrical power is being used.
(Source: http://www.edfenergy.com/products-services/large-business/PDF/B2B_ePublications/B2B-FS-RPG.pdf)

Synchronous condenser (rotating machine) **-** A synchronous machine running without mechanical load and supplying or absorbing reactive power (IEEE Standard Dictionary of Electrical and Electronics Terms – IEEE Std. 100-1992).

3 INTRODUCTION

This report provides the Board of Commissioners of Public Utilities (the Board) with information to support the proposed installation of a 100 MW (nominal) combustion turbine (CT) and balance of plant (BOP) at the Holyrood Generating Station location to be in service late in 2014. The proposed addition is intended to fulfil three main functions:

1. Additional long term generation capacity for the Island Interconnected System;
2. Additional generation capacity on the Avalon Peninsula to mitigate local generation supply and transmission contingencies; and
3. Replacement of the leased black start facility at the Holyrood Generating Station.

Newfoundland and Labrador Hydro's (Hydro's) *Generation Planning Issues - November 2012* report (see Appendix C) submitted to the Board in December 2012, identified an Island Interconnected System capacity deficit and violation of the accepted generation capacity criteria in 2015:

Capacity Criteria: The Island Interconnected System should have sufficient generating capacity to satisfy a Loss of Load Hours (LOLH) expectation target of not more than 2.8 hours per year.

Please see Table 3:

Table 3 - Island System Loss of Load Hours (LOLH)

2013- 2020

2013	2014	2015	2016	2017	2018	2019	2020
0.97	2.48	3.85	5.10	4.98	0.15	0.16	0.16

This capacity deficit and the long term options to rectify it were analyzed as part of the 2012 Muskrat Falls DG3 evaluation of the Isolated Island and Interconnected Island alternatives.

The results of that evaluation were presented in the report *Review of the Muskrat Falls and Labrador Island HVdc Link and the Isolated Island Options – October 2012 – Manitoba Hydro International* (see Appendix D*).*

The analysis indicated that based on the planning methodology and available generation options with the sanction of Muskrat Falls, the least long term cost option to reliably mitigate the capacity deficit in 2015 was a 50 MW (nominal) combustion turbine.

Much of the background for choosing the combustion turbine solution is also provided in the *Generation Planning Issues - November 2012* report (GPI) (see Appendix C). This report provides an overview of the Island Interconnected System generation capability for the next 20 years, the proposed timing of the next requirement for additional generation supply and the resources available to meet that requirement, and identifies issues that need to be considered to ensure a decision on the preferred source can be made.

In its generation planning analysis, Hydro used a nominal 50 MW as the minimum size of a combustion turbine in its planning process. On a capacity basis, simple cycle combustion turbines offer a low $/MW cost compared to hydro electric resources and are suited to peaking needs. This assumption on unit size is used to streamline the evaluation process to land on the range of required capacity. However, before making final recommendations, each situation is evaluated to determine if there is a benefit in making a change.

This present report provides the additional analysis completed by Hydro since the completion of the 2012 Generation Planning Issues report and the sanction of Muskrat Falls to result in the recommended solution for meeting the 2015 generation capacity shortfall.

4 Generation Capacity Planning Analysis Post Muskrat Falls Sanction

Hydro updated its generation planning analysis in the second half of 2013 in preparation for completing this application to the Board for additional generating capacity.

The forecast used in the 2013 review was the *2012 Island Planning Load Forecast – Interconnected Island Case.* It is discussed in Section 2 and in Appendix A of the *Generation Planning Issues – November 2012* report (see Appendix C).

Hydro has not issued an updated long term Generation Planning Load Forecast since 2012 but conducted a review of the previous forecast in 2013 and determined that it was still representative of the expected load during the period.

In the 2013 review, 60 MW was assumed as the minimum required combustion turbine size based on the 50 MW identified in previous reviews and an additional 10 MW to replace the 10 MW that had previously been available to the system from the black start facility at Holyrood.[8]

Options for New Generation Capacity Addition

In addition to the 60 MW combustion turbine, other options considered as part of the 2013 review included up to 100 MW of combustion turbine capacity, interruptible load arrangements with industrial customers, a review of the potential for CDM to meet the capacity shortfall, and the role of the currently leased black start diesel facility at Holyrood. This review considered both new and used or aftermarket combustion turbines Interruptible load arrangements with industrial customers offer an opportunity to reduce system demand by curtailing a customer’s load in return for a financial incentive without

[8] In early 2012, Hydro decided to discontinue operation of the 10 MW Holyrood combustion turbine for safety and asset condition reasons as a result of a report and recommendation completed in late 2011 by AMEC Americas.

adversely affecting the customer's operation. However, these arrangements can have limitations in terms of the number of times it can be called upon, the duration of the curtailment, and the time of year it can be called upon. These factors can affect the suitability to the utility. While these options have not been selected as the sole solution, they are recommended to be pursued to help resolve issues such as unforeseen loss of generation capacity, or as a mechanism to address extreme demand beyond the normal expected.

CDM continues to be a component of the supply side equation for Hydro. Working through both joint utility efforts and targeting Hydro customers directly, programs have continued to expand and reach new customers with new opportunities to save. The focus to date has been on energy savings and reduction of fuel at Holyrood. Capacity and demand reductions are also achievable through CDM once the necessary planning steps have taken place. CDM programs must be economically justified and updating the marginal cost study to reflect current system realities is the first step in that process. An assessment of the current opportunities for demand savings through an updated conservation potential study is also needed. This will confirm which technologies are currently being used by customers and assist in defining the magnitude of new technology opportunities for demand reduction in existence. The utilities undertook a CDM Potential Study in 2008 and are planning to begin an update in 2014 to reflect the changes in the customer market and technology developments. The 2008 study did not explore demand opportunities as capacity was not driving costs on the system. The planned update will address this issue.

As previously mentioned, the current focus of CDM programs has been energy conservation as it is tied to reducing fuel use, primarily at Holyrood. While demand reduction programs are demonstrating successful implementation in other jurisdictions, they take time to be accepted and implemented by customers. Where successful in reducing demand, these programs are generally aided by financial programs that support retrofitting homes, and a rate structure that motivates customers to invest in and change habits. While an enhanced

CDM program can be beneficial, it is not a viable option in the timeframe available to change consumer behavior and achieve savings. At this time, a CDM program that includes demand reduction in addition to energy reduction is considered a complementary program to the installation of the combustion turbine. Over time, enhanced CDM programs will serve to better manage overall system demand. However, in the period from now until December 2015, what is needed is a firm increase in generation, or an equivalently firm reduction in demand on the Avalon Peninsula to obtain both transmission and system capacity benefits.

The diesels installed at Holyrood are rated at 16 MW peak with a sustainable rating of 14.6 MW. However, limitations of plant equipment (breakers and cabling) limit the power available to the system to 10 MW. If the limitations of the breaker and cables are addressed, an additional 4.6 MW could be supplied to the system on a sustainable basis. These diesels are leased and the lease could be extended or the units purchased with the intent to redeploy following decommissioning of Holyrood's thermal generating capability. The cost and risk associated with changing breakers, cabling and other internal aspects of an existing operating plant to gain system access to an additional 4.6 MW is not recommended.

Impact of January 2014 Events on Generation Planning Decisions

In late December 2013 and early January 2014, Hydro experienced unrelated generation de-ratings at five separate generating stations resulting in a total generation unavailability of 233 MW. The generation unavailability combined with very cold temperatures driving high customer demand resulted in capacity shortfalls on both January 2 and January 3 requiring Hydro and NP to initiate rotating customer outages to preserve system integrity.

As a result of this significant and unprecedented interruption to customer supply, the January outages led to a review of many aspects of Hydro's operation which is still on going. One aspect was a review of the load forecasting methodology used by Hydro in planning the generation supply for the island. This review was carried out by Ventyx, an ABB Company with specialized expertise in this aspect of utility planning. The Ventyx report was filed by Hydro in Volume 2, Schedule 4, Appendix 1 of Hydro's Interim Report to the Board, *A Review of Supply Disruptions and Rotating Outages: January 2-8* filed on March 24, 2014 and is attached as Appendix E.

With respect to load forecasting Ventyx concluded "the methodology used by NP and NLH are consistent with accepted utility practices." (See page 12, Appendix 1 of the above report).

With respect to generation planning reserve criteria, Ventyx concluded that "NLH's generation planning reserve criterion of an LOLH of 2.8 hours per year is prudent and consistent with standard utility practices." (See page 23 of the above report).

In the area of generation outage rates, Ventyx suggested that Hydro continue to model its forced outage rates at Holyrood at the average rates actually experienced even though the rates tend to be marginally higher than industry averages.

The Ventyx report included recommendations for improvement in various areas, some of which could influence near term decisions. Ventyx suggested Hydro should conduct a sensitivity analysis to determine how increases in forced outage rates for the thermal generation, or how changes in the demand due to non-average or extreme loads, may impact LOLH and provide additional information to further inform the generation addition decision.

Ventyx also acknowledged that forced outage rate assumptions for hydraulic plants that Hydro used in the planning analysis were already higher than actual performance and that there was no basis for considering increases.

Based on the Ventyx recommendations which Hydro accepts, Hydro expanded its 2013 analysis to include sensitivities to show impact on LOLH of:

1. a reduced thermal generation availability;
2. a load forecast based on extreme weather; and
3. a combination of reduced availability and extreme load forecast.

5 RESULTS OF PLANNING ANALYSIS

Table 4 and Figure 1 below show the results of the analysis for the Base Case and the three sensitivity cases noted above. The Base Case reflects Hydro's current planning assumptions around: a) load forecast and b) outage rates, both of which Ventyx have determined to be prudent and reasonable for long term system planning.

The LOLH between 2014 and 2017 was evaluated for each case assuming the following combinations of generating capacity additions:

1. Installation of a 60 MW (nominal) combustion turbine by December of 2015;
2. Entering interruptible arrangements for 60 MW starting in 2014;
3. Combining a 60 MW CT and 60 MW of Interruptible (item 1 and 2);
4. Installation of a 100 MW CT by December 2014; and
5. Combining a 100 MW CT and 60 MW of Interruptible (item 2 and 4).

Table 4: Base Case (LOLH)

Normalized Forecast and Usual Outage Rates	LOLH							
Base Case	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
No Mitigation Pre Muskrat	0.97	2.48	3.85	5.10	4.98	0.15	0.16	0.16
60 MW CT 2015	0.97	2.48	3.36[9]	2.34	2.34	0.15	0.16	0.16
60 MW Interruptible 2014	0.97	1.17	1.93	2.66	2.72	0.15	0.16	0.16
60 MW interruptible 2014 & 60 MW CT 2015	0.97	1.17	1.68	1.11	1.17	0.15	0.16	0.16
100 MW CT 2014	0.97	2.08	0.96	1.31	1.33	0.15	0.16	0.16
60 MW interruptible 2014 & 100 MW CT 2014	0.97	0.98	0.41	0.58	0.64	0.15	0.16	0.16
LOLH Criteria	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8

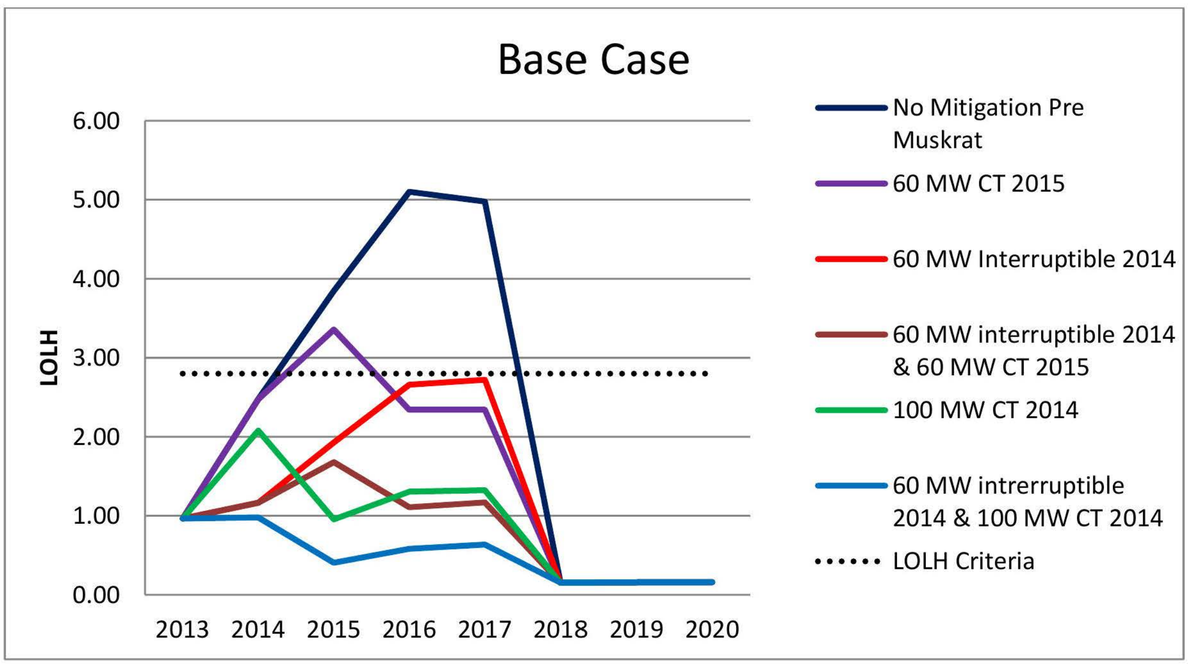


Figure 1

[9] This calculation did not include the interruptible in place until March 2014. Had it been included, the number would be somewhat less.

From the Base Case presented as Table 4 and Figure 1 above, which is for a peak load using average peak day weather conditions and base generation reliability assumptions used in previous studies, a 60 MW CT with an in service date of December 1, 2015 reduces the LOLH but does not reduce it to less than 2.8 hours. These values are indicated in red in the table. While the table indicates a 2015 LOLH of 3.36 hours, it should be noted that the exposure would be limited to January, February and possibly March and as long as the new CT is in service by December. The actual December contribution to the LOLH will be low as evidenced by the LOLH for 2016 of 2.34 hours. Earlier installation of a combustion turbine, such as a 100 MW unit in 2014, fully mitigates the 2015 LOLH violation. As well, assuming a 60 MW interruptible arrangement can be in place late in 2014, the criteria is met, but with limited margin for years prior to the HVdc interconnection.

Reduced Thermal Generation Availability

Given the age of the thermal plant at Holyrood and the existing combustion turbines, and based on the performance of some of these units over the past two years, the scenarios presented in Figure 1 were re-evaluated with reduced reliability for the thermal and combustion turbine plants. The parameters used in Strategist software, the program used to perform this analysis, for Thermal Generation (Holyrood) are Derated Adjusted Forced Outage Rate (DAFOR) and, as a sensitivity, the rate was increased by 2 per cent above the Base Case assumption of 9.6 per cent to 11.64 per cent. The parameter used for combustion turbines is the Utilization Forced Outage Rate (UFOP) and this was increased by 10 per cent above base case of 10.62 per cent to 20.6 per cent. For purposes of discussion, they will be referred to as simply outage rates in this report. While these increased outage rates are higher than the longer term averages, there have been certain years when the rates have been higher.

The results of this analysis are presented in Table 5 and Figure 2.

Table 5: Reduced Fossil Plant Reliability (LOLH)

Holyrood +2% DAFOR CTs +10% UFOP								
Base & Reduced Fossil Plant Reliability	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
No Mitigation Pre Muskrat	0.97	4.29	6.56	8.54	8.25	0.15	0.16	0.16
60 MW CT 2015	0.97	4.29[10]	5.79	4.10	4.02	0.15	0.16	0.16
60 MW Interruptible 2014	0.97	2.21	3.60	4.87	4.89	0.15	0.16	0.16
60 MW interruptible 2014 & 60 MW CT 2015	0.97	1.96	1.52	2.12	2.18	0.15	0.16	0.16
100 MW CT 2014	0.97	3.63[10]	1.73	2.32	2.31	0.15	0.16	0.16
60 MW interruptible 2014 & 100 MW CT 2014	0.97	1.87	0.79	1.12	1.18	0.15	0.16	0.16
LOLH Criteria	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8

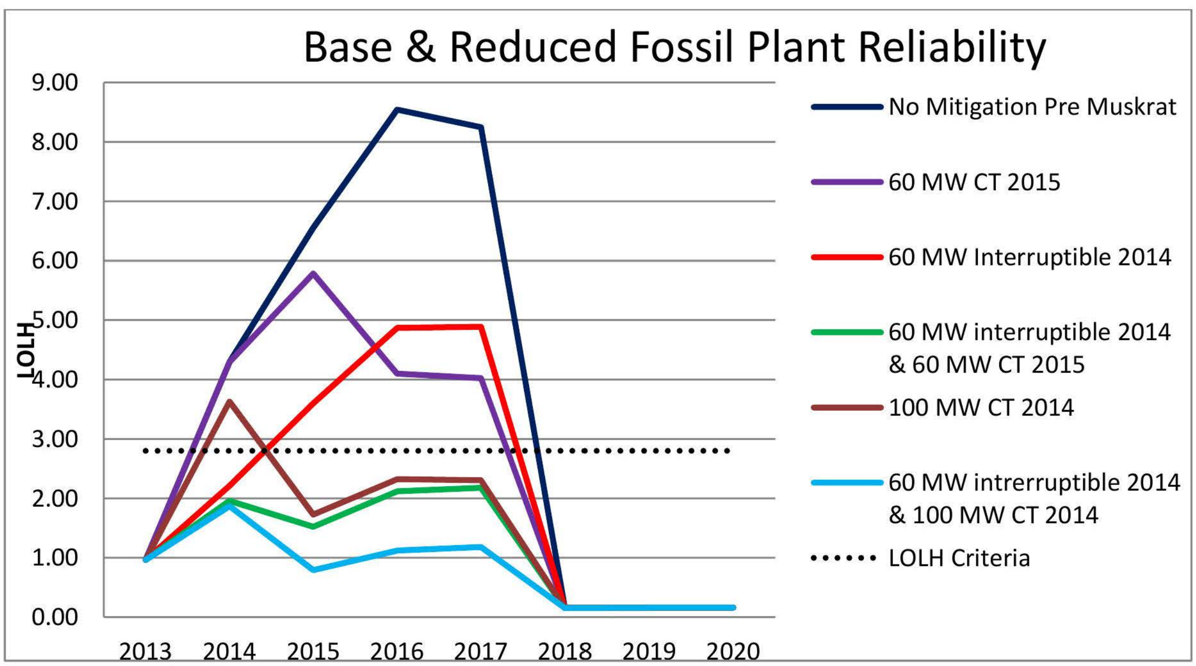


Figure 2

[10] This is above the criteria of 2.8 hours, however in the cases of additional CTs they are planned to be in service in December thus mitigating some of the exposure.

From this analysis (which adjusted the outage rates of Holyrood and the combustion turbines) the resultant LOLHs are, as expected, higher than for the Base Case. This situation would be somewhat similar to this past winter of 2013-2014 where multiple units were unavailable or at reduced capacity. The 60 MW interruptible alone does not meet the criteria, nor does a 60 MW combustion turbine. A 100 MW combustion turbine in December 2014 resolves the 2015 criteria shortfall and that will be sustained until the HVdc interconnection is in service. While the Table indicates a 2014 LOLH of 3.63 hours, it should be noted that the exposure would be for January, February and possibly March, now past, and as long as the new CT is in service by December. The actual December contribution to the LOLH will be low as evidenced by the LOLH for 2016 of 1.73 hours.

Extreme Weather Load Forecast

The load forecast Hydro uses in its utility planning is a weather normalized forecast which effectively means an average peak forecast or what is referred to as a P 50 forecast. Simply stated, the actual peak has a 50 per cent chance of being either higher or lower than that figure. When there is extreme wind and cold, the actual peak can obviously be greater than the average figure. A P 90 forecast was generated which assumes an extreme wind chill at the time of peak. The P 90 forecast adds an additional 57 MW to the P 50 demand with a 90 per cent probability of the actual peak being lower and conversely only a 10 per cent probability of the actual load exceeding forecast load. The results of considering a P 90 load forecast analysis are presented in Table 6 and Figure 3.

Table 6: Increased Demand (LOLH)

Base & Increased Demand	2013	2014	2015	2016	2017	2018	2019	2020
No Mitigation Pre Muskrat	0.97	4.86	7.10	9.09	8.39	0.15	0.16	0.16
60 MW CT 2015	0.97	4.86[11]	6.23	4.62	4.38	0.15	0.16	0.16
60 MW Interruptible 2014	0.97	2.39	3.72	4.94	4.83	0.15	0.16	0.16
60 MW interruptible 2014 & 60 MW CT 2015	0.97	2.39	3.25	2.26	2.26	0.15	0.16	0.16
100 MW CT 2014	0.97	4.06[11]	2.03	2.69	2.60	0.15	0.16	0.16
60 MW interruptible 2014 & 100 MW CT 2014	0.97	2.00	0.92	1.26	1.28	0.15	0.16	0.16
LOLH Criteria	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8

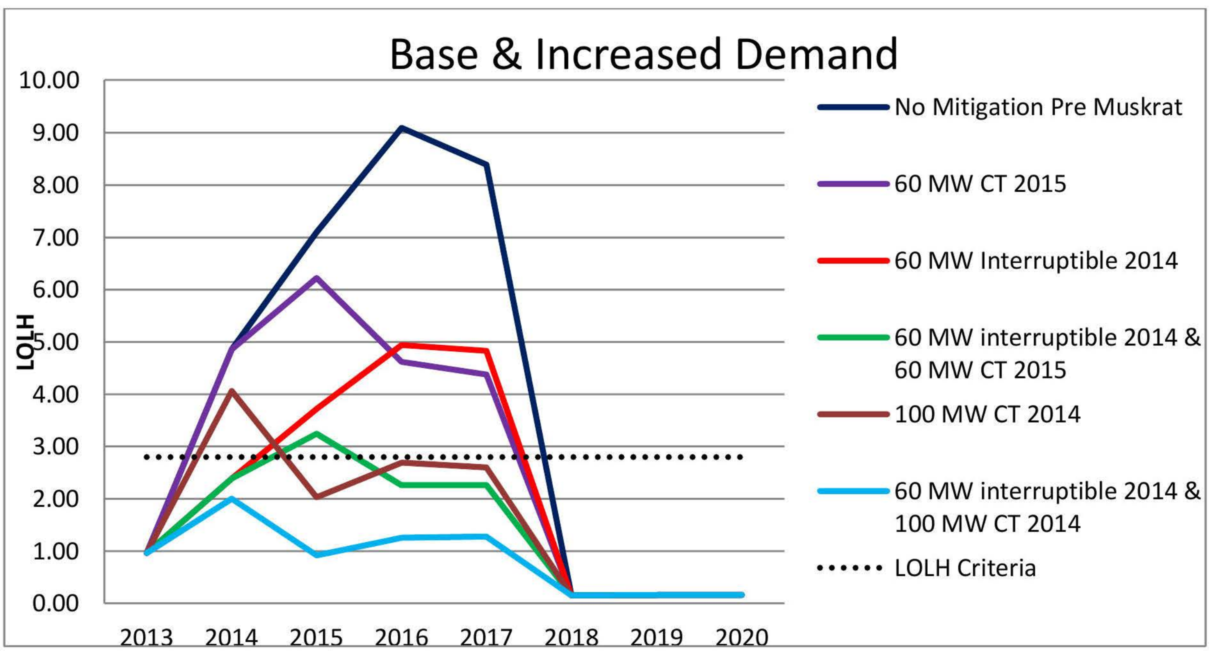


Figure 3

[11] This is above the criteria of 2.8 hours, however in the cases of additional CTs they are planned to be in service in December thus mitigating some of the exposure.

In this scenario, the results are similar to the increased outage rate scenario however only the 100 MW combustion turbine and the 100 MW combustion turbine along with the 60 MW interruptible meet the criteria of 2.8 hours throughout. The 60 MW combustion turbine along with the 60 MW interruptible results in a LOLH of 3.25 in 2015. This condition will be present through the winter of 2015 and will only be mitigated with the installation of the 60 MW combustion turbine in December 2015. While the Table 4 indicates a 2014 LOLH of 4.06 hours for the 100 MW unit in 2014 it should be noted that the exposure would be for January, February and possibly March, of 2014 which is now past. As the new CT is planned to be in service by December the actual December contribution to the LOLH will be low as evidenced by the LOLH for 2015 of 2.03 hours. Assuming the 100 MW CT is in service by December 1, 2014, further capacity additions or interruptible sources would not be required to meet the criteria for the 2014-15 winter season. For 2016 and 2017, the 100 MW CT alone is marginally under the criteria of 2.8 hours.

Combination of Reduced Availability and Extreme Load Forecast

An even more severe scenario would be a P 90 load forecast combined with increased outage rates at the Holyrood station and for the combustion turbines. The results of this scenario are presented in Table 7 and Figure 4.

Table 7: Increased Demand & Reduced Reliability (LOLH)

+ 57 MWs, Holyrood +2% DAFOR, CTs +10% UFOP								
Base & Increased Demand & Reduced Reliability	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
No Mitigation Pre Muskrat	0.97	7.75	11.19	14.16	13.04	0.15	0.16	0.16
60 MW CT 2015	0.97	7.75[12]	9.93	7.42	6.98	0.15	0.16	0.16
60 MW Interruptible 2014	0.97	4.16	6.37	8.31	8.04	0.15	0.16	0.16
60 MW interruptible 2014 & 60 MW CT 2015	0.97	4.16	5.62	3.97	3.90	0.15	0.16	0.16
100 MW CT 2014	0.97	6.56[12]	3.39	4.42	4.21	0.15	0.16	0.16
60 MW interruptible 2014 & 100 MW CT 2014	0.97	3.51	1.67	2.24	2.23	0.15	0.16	0.16
40 MW interruptible 2014 & 100 MW CT 2014	0.97	4.35	2.13	2.83	2.77	0.15	0.16	0.16
20 MW interruptible 2014 & 100 MW CT 2014	0.97	5.36	2.69	3.54	3.42	0.15	0.16	0.16
LOLH Criteria	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8

[12] This is above the criteria of 2.8 hours, however in the cases of additional CTs they are planned to be in service in December thus mitigating some of the exposure.

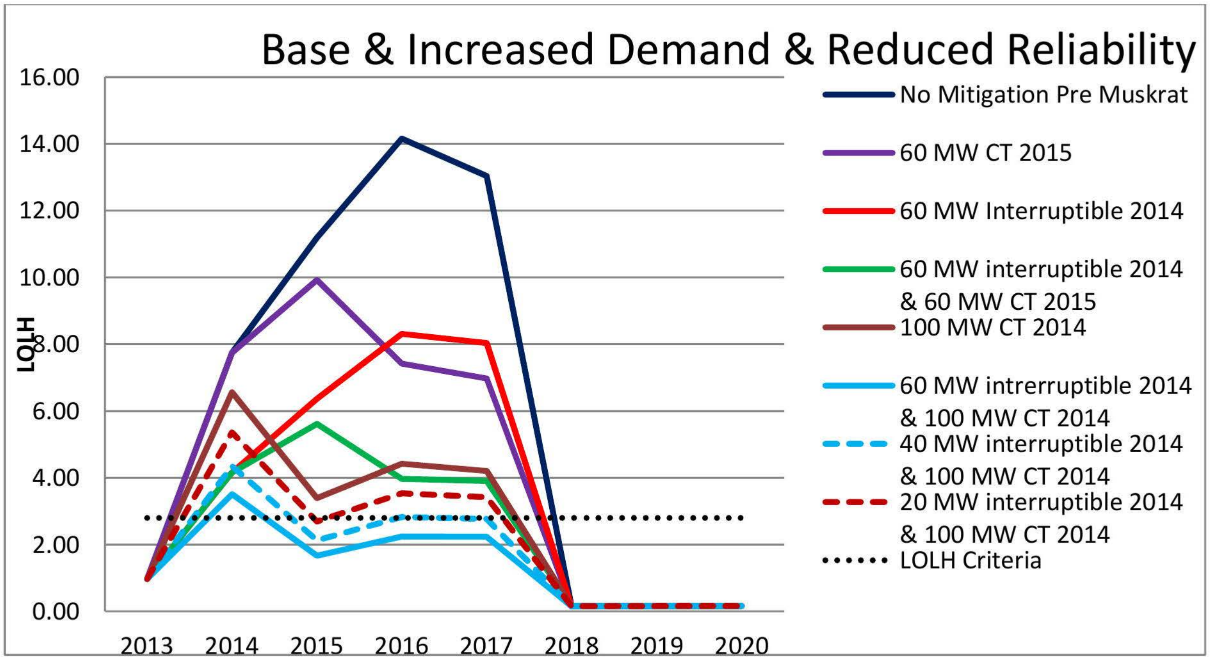


Figure 4

For this sensitivity, the only solution that provides a LOLH below the 2.8 hour target would be the 100 MW combustion turbine combined with 60 MW of contracted interruptible arrangements. It is worth noting that there is a low probability of occurrence for the combined sensitivity.

Generation Reserve Margin

The generation reserve margin is another measure of reliability and is an indication of the margin between firm available continuous generation capacity and firm expected load. The firm continuous capacity ratings are representative of the winter operating season where ice and wind can impact plant output. For instance, wind turbine capacity is assumed to be zero due to high winds and Exploits generation is assumed to be 63 MW reflecting its continuous capability. In addition, the 50 HZ generation at Deer Lake is netted out as it cannot be made available to the 60 HZ system, and Newfoundland Power's hydraulic generation is reduced by a reserve margin which better reflects the continuous capability of their plants. For the current system overall, the installed nameplate capacity including the leased diesels, on the island is 2012.9 MW and the continuous rating of what is assumed to be available is 1867.9 MW, a reduction of 145 MW.

Table 8: Reserve Margin-Continuous Rating

Year	Forecast Peak Demand MW	Existing	40 MW Int.	60 MW Int.	100 MW CT	100 MW CT +40 MW Int.	100 MW CT +60 MW Int.
2014	1691	10.5%	12.8%	14.2%	15.8%	18.3%	19.7%
2015	1721	8.5%	10.8%	12.2%	13.8%	16.2%	17.6%
2016	1736	7.6%	9.8%	11.2%	12.8%	15.1%	16.5%
2017	1755	6.4%	8.6%	9.9%	11.6%	13.9%	15.2%

Table 8 above reflects the reserve margin as a percentage of the continuous generation rating.

For example for the existing system with no additions prior to Muskrat Falls, the reserve would decrease from 10.5 per cent to 6.4 per cent from 2014 to 2017. This represents a reserve of approximately 177 MW in 2014 declining to 113 MW by 2017.

With 60 MW of interruptible the reserve improves to a range of 14.2 per cent down to 9.9 per cent or 233 MW down to 167 MW through the period.

The more capacity added, the higher the reserve and the more robust the system.

Transmission Reliability Considerations

The construction of Muskrat Falls and HVdc interconnections between Labrador and the island, and the island and Nova Scotia, will permanently alter the electrical system landscape on the Island of Newfoundland. The island will no longer be isolated and with two interconnections to the North American electrical system, the options available to ensure and enhance power system reliability will expand significantly. However prior to the completion of the HVdc interconnections, Hydro must ensure a cost effective reliable supply for the island's power and energy needs with enough capacity to accommodate some variation in the demand forecast, as well as consider the availability of all its generation fleet. While the electrical landscape of the province will change post 2017, any new generation added to secure system reliability prior to the interconnections will continue to be used and useful into the future and will provide enhanced system security during transmission contingencies which could include:

- Increased reliability and security for the Avalon Peninsula during both planned and unplanned transmission line outages;
- On-island capacity to support existing island generation and imports from Nova Scotia in the unlikely event of a bipole failure on the Labrador Island Link (a low probability occurrence); and
- Additional on-island generation to support reliable operation during monopole operations as a result of a single pole outages on the Labrador Island Link.

6 RECOMMENDATION BASED ON PLANNING ANALYSIS

Based on the evaluation using Base Case assumptions, it appears the LOLH reliability can be maintained by either a 60 MW combustion turbine or 60 MW interruptible load arrangements. While interruptible arrangements may satisfy LOLH it does not provide the same immediate or long term benefits provided by a combustion turbine and is not deemed acceptable as a sole solution.

In the near term, a combustion turbine located at Holyrood provides:

- Increased reliability and security for the Avalon Peninsula particularly during generation and transmission line contingencies;
- The ability to reduce transmission line losses especially during contingency conditions; and
- The ability to return the leased black start diesels at Holyrood.

In the longer term, the combustion turbine provides:

- Continued reliability and security for the Avalon Peninsula;
- On-island capacity to support existing island generation and imports from Nova Scotia in the unlikely event of a bipole failure on the Labrador Island Link (a low probability occurrence); and
- Additional on-island generation to support reliable operation during monopole operations as a result
- of a single pole outage on the Labrador Island Link. When operating in a sustained monopole mode, capacity from Labrador is reduced by approximately 280 MW. The combustion turbine provides on-island reserve to assist with reliable operation during these potential contingencies by helping meet the demands or reduce possible short term purchases via the Maritime Island Link. System design has assumed a CT of at least 60 MW to be available in this role. The addition of a larger combustion turbine will make the future system even more robust.

Considering the results of the sensitivity analysis, and recent experience, there is a significant benefit for additional capacity beyond the nominal 60 MW. Also, sensitivities indicate the level of LOLH violation in the early winter of 2015 could be significantly higher than that indicated in the Base Case if higher load or reduced reliability is experienced. Therefore, there is significant benefit to have mitigations in place prior to the beginning of the 2014-15 winter season.

7 COMBUSTION TURBINE OPTIONS

To meet the 2015 capacity deficit, Hydro had been advancing its preliminary engineering work for a new combustion turbine. A formal risk workshop was conducted in March of 2012 to assess three identified potential sites for additional combustion turbine capacity on the Avalon, close to the major load centres. Given the growth on the eastern portion of the system and the increased security and operating flexibility gained by locating the new generation on the Avalon Peninsula, locations off the Avalon were not considered. This assessment concluded that of the three potential sites, Holyrood was the preferred location (See Appendix F).

The estimates for the alternatives were initially developed in-house and based on vendor data and relevant information on construction costs current at the time. Following these initial estimates, contact was established with various suppliers to get current budgetary quotes for an Engineer Procure and Construct (EPC) contract to supply and install a combustion turbine and unit transformer at Holyrood. Several of these potential vendors visited Hydro and the proposed site to discuss our requirements and to discuss their product and capabilities. One of the more comprehensive proposals was selected as the basis for the estimates. The initial estimates by the vendor were revised following initial discussions and are reflected in this proposal.

The cost estimates and schedules for the 60 MW (nominal) unit were developed and adjusted as additional information was acquired. The current 60 MW alternative is estimated at $117.5M. Through discussion and consideration of other modifications to aid system integration and future development, the possibility of adding a larger generator to aid integration of the Labrador Island HVdc Link (LIL) in terms of MVAR support for the HVdc converter station was reviewed. As well, given the possibility of the larger generator it was natural to consider provision for future expansion. Adding a second turbine at some point in the future could increase the plant output to 120 MW. This concept would be similar to existing plants at Stephenville and Hardwoods where the generator sits between two combustion turbines and either turbine can be run separately for half power or together for full power. Overall, this concept would involve a larger transformer, generator, and building to accommodate a second turbine at some point in the future. These additions would increase the project cost by $3.3M from $117.5M to $120.8M. This proposal was scheduled to be in service in December of 2015. If required the full 120 MW facility with two 60 MW combustion turbines could be installed by December 2015 at a cost of $151.2M.

In addition to the new build 60 MW combustion turbine, since the winter of 2013 Hydro has been exploring aftermarket capacity options to mitigate generation capacity shortfalls. This was initiated after the failure of Unit 1 in Holyrood in January 2013 as it was considered prudent to understand the options available for a sudden significant loss of generating capacity. Hydro has remained in contact with sellers of combustion turbine equipment as it prepared for the identified 2015 capacity requirement.

This work has resulted in the identification of a number of aftermarket options that can be used to meet the 2015 capacity requirement. While options put forward included used, used but overhauled, and unused units, the current discussion has been on unused units. Hydro has not considered used combustion turbines but limited the review to unused units as they would likely bring more certainty on final cost and reliability. These are generally units that were purchased by various corporations and, for various reasons, were not installed or if so never placed into service. There were several units that were put forward that could fill Hydro’s need. The delivery and installation dates are obviously more attractive than those for new units ordered from original equipment manufacturer (OEM) vendors.

Other utilities have procured similar units and have experienced positive results. Hydro was in contact with one generation utility and made a site visit to discuss their experience. This company had acquired an 85 MW unit and reported they were very pleased with the unit’s condition and performance after installation.

There are various options available in the “aftermarket” of varying size, some of which are of significant interest to Hydro - both because of cost and an earlier in service potential. An accelerated schedule for installation could see such unit(s) being in service in December 2014. One such unit is an unused 113 MW ISO (international standard for rating combustion turbines) rated unit that was purchased new in 2008 but never installed and has been maintained to like new condition in storage in the United States.

In summary, the options considered, including the 113 MW unit, one of the most attractive of the aftermarket alternatives evaluated are presented in Table 9 with the estimated capital cost, as well as the $/kW to better compare the options.

Table 9: Combustion Turbine Summary Estimates

Alternative	In Service Date	Cost $Millions	$/kw
60 MW new, no expansion capability, includes Synchronous Condenser capability and generator and transformer sized for 60 MW nominal rating	Dec. 2015	$117.5	$1958
60 MW new, expandable to 120 MW, includes Synchronous Condenser capability and generator and transformer sized per ultimate rating	Dec. 2015	$120.8	$2014
120 MW new plant, includes Synchronous Condenser capability with generator and transformer sized per ultimate rating	Dec. 2015	$151.3	$1261
113 MW after market, new and unused, no Synchronous Condenser capability	Dec. 2014	$118.9	$1052

Based on the level of input to the estimating process, the estimates used in this report are considered Class Three estimates per the Association for the Advancement of Cost Engineering (AACE)[13] and thus within an accuracy of plus 20 per cent to minus 10 per cent.

A number of these options could mitigate much of the increased LOLH risk identified in the capacity planning sensitivity analysis. In particular, the 113 MW combustion turbine that could be in service by December 2014 would alone mitigate much of the increased LOLH risk identified in the sensitivity analysis. In fact, this unit with an ISO rating of 113 MW

[13] Class Three is defined in AACE International Recommended Practice No. 17R-97, "Cost Estimate Classification System'.

would be capable of generating approximately 120 MW in winter conditions. This, in addition to possible industrial customer interruptible agreements, would place Hydro's system in a very secure position going into the 2014-2015 winter season and through to 2018.

8 COST ESTIMATE FOR PROPOSED COMBUSTION TURBINE

The cost of the 113 MW unit was estimated to be $118.9M and can be installed in 2014 with timely approvals. The breakdown of these costs are presented in Table 10.

Table 10: Project Budget Estimate 113 MW Combustion Turbine, After Market

Project Cost: *($ 1,000)*	**2014**	**2015**	**Total**
Material Supply	2,060.3	0.0	2,060.3
Labour	3,522.9	53.9	3,576.8
Consultant	1,852.4	0.0	1,852.4
Contract Work	89,424.7	0.0	89,424.7
Other Direct Costs	361.5	0.0	361.5
Interest and Escalation	2194.2	0.7	2194.9
Contingency	19,455.1	0.0	19,455.1
TOTAL	**118,871.1**	**54.6**	**118,925.1**

This 113 MW combustion turbine, if procured and installed by December 2014, offers enhanced reliability and value for customers when compared to a new 60 MW unit which cannot be in service until at the earliest, December 2015 at practically the same cost. Having this unit in service in December 2014 significantly reduces the risk associated with colder than forecast weather or unplanned outages due to equipment breakdown. This is reflected in the LOLH and reserve margin analysis previously presented. The installed cost per MW for a new 60 MW unit is approximately $1,959/kW. For a new 120 MW unit the estimated cost is $1,260/kW. The 113 MW aftermarket unit is estimated to cost approximately $1,052/kW.

9 CONCLUSION

This report supports the proposed installation of a 100 MW (nominal) combustion turbine and BOP at the Holyrood Generating Station location. The proposed addition will provide two main functions, as follows:

1. Additional 100 MW (nominal) of system generation capacity for the Island Interconnected System to satisfy established generation planning criteria;
2. Additional generation capacity on the Avalon Peninsula to mitigate local generation supply and transmission contingencies; and
3. Replacement of existing black start facility at the Holyrood Generating Station.

While synchronous condenser capability is a desirable feature, if its provision would mean delays in the initial in service date of the combustion turbine, it would not be considered critical. This capability will not be required until 2017 and it can be pursued later.

System Planning's *Generation Planning Issues - November 2012* report (see Appendix C) identified a capacity deficit and violation of Hydro's generation capacity criteria in 2015.

This capacity deficit and the long term options to rectify it were analyzed as part of the DG3 evaluation of the Isolated Island and Interconnected Island alternatives. The results of that evaluation were presented in the report *Review of the Muskrat Falls and Labrador Island HVdc Link and the Isolated Island Options – October 2012 – Manitoba Hydro International (see attached in Appendix D).* The same analysis was also used as the basis for the *Generation Planning Issues – November 2012* report.

The result of that analysis indicated that the least cost long term option to mitigate the capacity deficit in 2015 is a 50 MW (nominal) combustion turbine.

Much of the background for proposing this project is given in the *Generation Planning*

Issues - November 2012 report (see Appendix C) which provides an overview of the Island Interconnected System generation capability for the next 20 years, the proposed timing of the next requirement for additional generation supply, the resources available to meet that requirement, and identifies issues that need to be considered to ensure a decision on the preferred source can be made through a timely and cost-effective process.

A recent review using base load forecast and generation availability assumptions confirmed the LOLH capacity violation for 2015. This review considered alternatives including various sizes of combustion turbines, varying sizes of interruptible load contracts and combinations of both. In addition a sensitivity analysis was performed to determine the impact of both increased load forecast and decreased thermal generation availability. Given the results of the sensitivity analysis combined with the possibility of acquiring a combustion turbine with a 2014 in-service date there is justification to investigate acquiring up to 100 MW of combustion turbine capability for an in-service as early as December 2014

A functional performance specification has been prepared and a public tender was issued on April 7 soliciting bids for EPC services to supply and install 100 MW (nominal) of combustion turbine generating capacity. This tender calls for the unit(s) to be in service in December, 2014 and only bids utilizing new or unused “after market” turbines will be considered. The tender permits up to a maximum of four units totaling 100 MW. The tender will close on April 21, 2014 and award is subject to the Board’s approval of this project.

10 PROJECT DESCRIPTION

The proposed Holyrood 100 MW (Nominal) Combustion Turbine Addition Project will primarily be completed by a consultant via an EPC contract and will include, but is not limited to the installation of:

- 100 MW (nominal) combustion turbine capacity;
- Associated electric generators;

- Building;
- 13.8 kV unit breakers;
- Associated step-up transformer(s);
- De-mineralized Water Plant;
- BOP; and
- Fuel storage.

In order to provide greatest value for its customers, Hydro will accept only tenders from suppliers which include generating units with proven reliable records, in reliable operating order, and with a minimum of a one year warranty.

Internal resources will be utilized to design and install interconnections for the new transformer at the existing Holyrood Terminal Station's 230 kV bus B15 by completing the breaker and half element with the addition of a 230 kV breaker and associated disconnect switches. Internal resources will also participate in pre-commissioning, commissioning, and O&M training.

Potential interconnection single line diagrams for both single unit and multiple unit installations are presented in Appendix A.

In addition, an internal multi-discipline design team will provide the Basis of Design, detailed design of interconnections/site civil works, directional/technical input and review of equipment specifications/tender packages throughout the duration of the project. An internal Project Manager will represent Hydro and provide overall project management support. An internal Owner's Commissioning Coordinator will be appointed to develop the project's overall Commissioning Plan (CP) and interface with the Consultant's Commissioning Coordinator to ensure quality and that the CT stays on cost and schedule.

The project is subject to review under the Province's Environmental Assessment (EA) process and construction cannot proceed until this is complete and the Project has been released from further environmental assessment. Hydro's Environment Department is conducting an initial screening study to identify system and regulatory requirements associated with noise, emissions, fuel delivery, ecological and surrounding infrastructure sensitivities and will also lead the development of required Environmental Registration documentation and support the project throughout the EA process.

The project includes the following assumptions:

- The Board's Project Approval by April 2014;
- Project EA release within 45 days of registration;
- Minimum preliminary engineering work to protect the schedule commenced in early 2014;
- Project Execution Via EPC Contract;
- Project In Service by December 2014 to meet 2014/2015 peak; and
- Project Location is Holyrood Generating Station Yard – between the old guard house and the Terminal Station (see Appendix B).

An initial formal risk workshop was conducted in March of 2012 (See Appendix F). This workshop reduced site alternatives from three down to one – Holyrood. The main site risks identified were associated with Environmental and Schedule. The Risk Management Plan will continue to be updated as the project progresses through its phases.

Project costs were updated to an estimate of $118.9M in Q1 2014 and this is an Association for Advancement of Cost Engineering (AACE)[14] class three estimate, with an accuracy of plus 20 per cent minus 10 per cent.

[14] Class Three is defined in AACE International Recommended Practice No. 17R-97, "Cost Estimate Classification System'.

It is planned that project field work will start in the second quarter of 2014, with completion by December 2014. It will be executed via EPC contract and an internal design team will be used to provide the Basis of Design, review and approval of ongoing designs/specifications/tenders/sub-contracts, and regular monitoring of consultant progress. Interconnections (230 kV connection to Holyrood Terminal Station, fire protection, and water/sewer/storm) to/from this facility and site civil works will be designed and procured by internal engineering design resources and installed by internal resources. There will also be some modifications to existing 230 kV structures and P&C Panels in the Holyrood Terminal Station to accommodate the new equipment. Communications equipment will be added to integrate the CT with Hydro's Energy Control Centre for operations and control starting and stopping as are other such assets in the Hydro system.

11 SCHEDULE

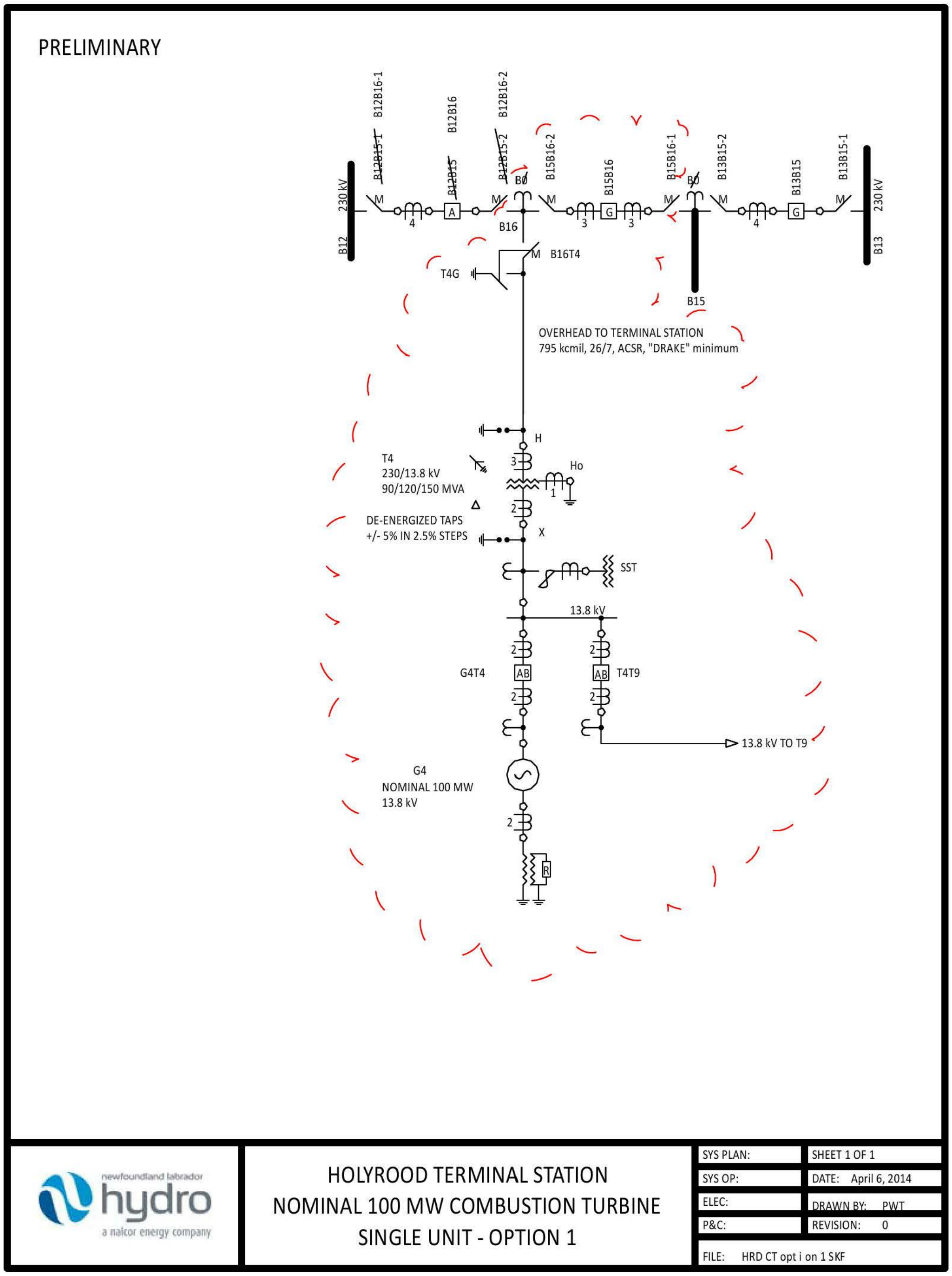
Table 11: Project Schedule

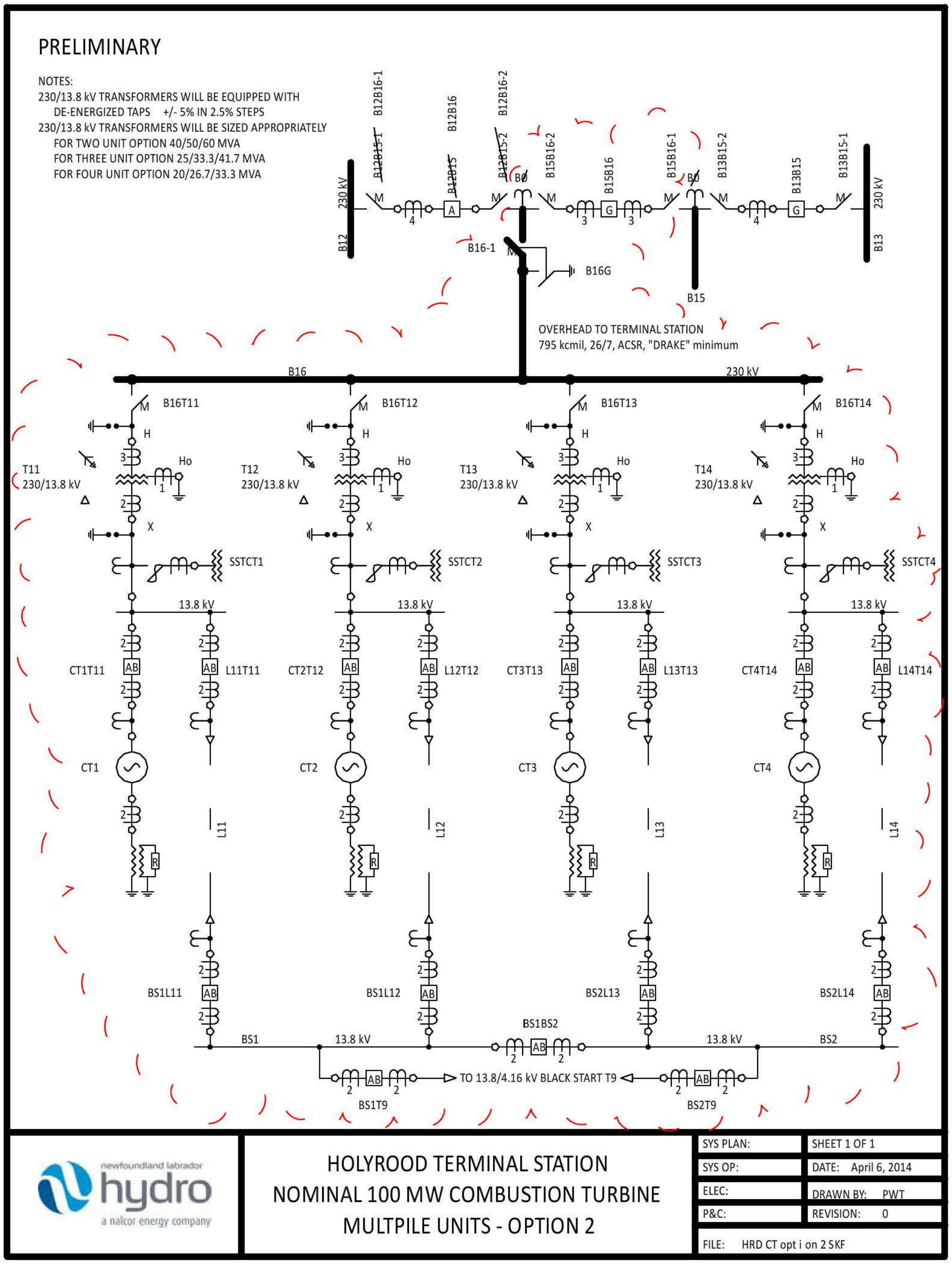
Activity		Start Date	End Date
Planning	Activity 1: Define Technical Performance Specifications and Operating Profile	Jan. 2014	Apr. 2014
	Activity 2: Define Environmental Assessment Registration and Permitting Requirements	Mar. 2014	Apr. 2014
	Activity 3: Define Geotechnical Investigation Requirements	Mar. 2014	Apr. 2014
	Activity 4: Define Project Execution Strategy and Project Schedule	Feb. 2014	Apr. 2014
Design	Activity 1: Develop Performance Specification and Tender Document for EPC Contract for Turnkey Combustion Turbine Generator (CTG)	Mar. 2014	Apr. 2014
	Activity 2: Complete Air Emissions Dispersion Modeling	Mar. 2014	Apr. 2014
	Activity 3: Finalize and Submit Environmental Assessment Registration Documentation	Apr. 2014	Apr. 2014
	Activity 4: Conduct Stakeholder Consultations	Apr. 2014	Apr. 2014
	Activity 5: Develop Specifications for Long Lead Equipment: 230 kV Breaker/MODs, Transmission Towers, Lightning Arrestors	Apr. 2014	Apr. 2014
	Activity 6: Design and Develop Specifications for Interconnection Infrastructure (Terminal Station, Demineralized Water, Water & Sewer, Protection & Control, etc.)	Apr. 2014	May 2014
	Activity 7: Turnkey Design (by EPC Contractor) for CTG	Apr. 2014	Jul. 2014
Procurement	Activity 1: Award EPC Contract for EPC Contract for Turnkey Combustion Turbine Generator	Apr. 2014	Apr. 2014
	Activity 2: Order Long Lead Equipment: 230 kV Breaker/MODs, Transmission Towers, Lightning Arrestors	Apr. 2014	May. 2014
	Activity 3: Award Contract for Interconnection Infrastructure Construction	May 2014	May 2014
	Activity 4: Procurement of CTG and Balance of Plant including building, water systems, fuel systems, fire protection, controls, GSU, etc. by EPC Contractor	Apr. 2014	Aug. 2014
Construction	Activity 1: Construction of Interconnection Infrastructure	May 2014	Aug. 2014
	Activity 2: Construction of CTG and Balance of Plant including civil, building, water systems, fuel systems, fire protection, controls, GSU, etc. by EPC Contractor	May 2014	Nov. 2014
Commissioning	Activity 1: Commission Water System	Aug. 2014	Nov. 2014

Activity		Start Date	End Date
	Activity 2: Commission Control System	Sept. 2014	Nov. 2014
	Activity 3: Commission Electrical System	Oct. 2014	Nov. 2014
	Activity 4: Commission Fuel System	Oct. 2014	Nov. 2014
	Activity 5: Commission Interconnection Infrastructure (HRD TS)	Aug. 2014	Sept. 2014
	Activity 6: Commission Communications, SCADA, Metering Equip.	Oct. 2014	Nov. 2014
	Activity 7: Commission Combustion Turbine	Nov. 2014	Dec. 2014
	Activity 8: Complete Release For Service Forms	Dec. 2014	Dec. 2014
Closeout	Activity 1: Complete project deficiencies	Nov. 2014	Nov. 2014
	Activity 2: Complete As-Builts	Dec. 2014	Dec. 2014
	Activity 3: Complete Asset Assignments	Dec. 2014	Dec. 2014
	Activity 4: Issue final contract payments	Jan. 2015	Jan. 2015
	Activity 5: Conduct Post Implementation Review	Jan. 2015	Feb. 2015
	Activity 6: Close JDE Capital Job Cost	Feb. 2015	Feb. 2015

APPENDIX A

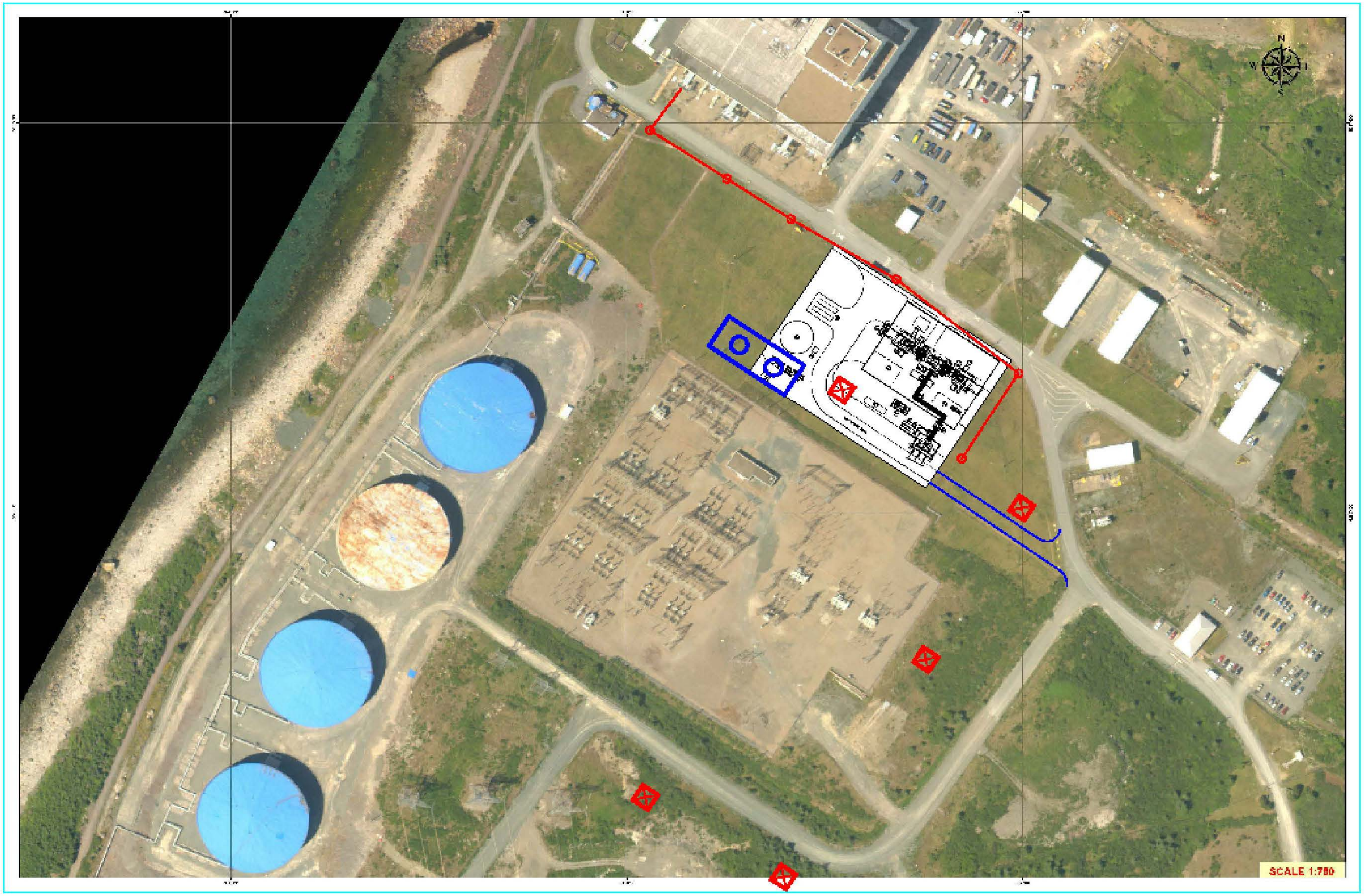
Proposed Single Line Diagrams


PRELIMINARY
B12B16-1
B12B16
B12B16-2
~~B12B15-1~~
~~B12B15~~
~~B12B15-2~~
B15B16-2
B15B16
B15B16-1
B13B15-2
B13B15
B13B15-1
B12
230 kV
B13
230 kV
B16
B15
B16T4
T4G
OVERHEAD TO TERMINAL STATION
795 kcmil, 26/7, ACSR, "DRAKE" minimum
H
Ho
X
T4
230/13.8 kV
90/120/150 MVA
DE-ENERGIZED TAPS
+/- 5% IN 2.5% STEPS
SST
13.8 kV
G4T4
T4T9
13.8 kV TO T9
G4
NOMINAL 100 MW
13.8 kV
newfoundland labrador hydro
a nalcor energy company
HOLYROOD TERMINAL STATION
NOMINAL 100 MW COMBUSTION TURBINE
SINGLE UNIT - OPTION 1
SYS PLAN:
SHEET 1 OF 1
SYS OP:
DATE: April 6, 2014
ELEC:
DRAWN BY: PWT
P&C:
REVISION: 0
FILE: HRD CT opt i on 1 SKF


PRELIMINARY
NOTES:
230/13.8 kV TRANSFORMERS WILL BE EQUIPPED WITH
DE-ENERGIZED TAPS +/- 5% IN 2.5% STEPS
230/13.8 kV TRANSFORMERS WILL BE SIZED APPROPRIATELY
FOR TWO UNIT OPTION 40/50/60 MVA
FOR THREE UNIT OPTION 25/33.3/41.7 MVA
FOR FOUR UNIT OPTION 20/26.7/33.3 MVA
B12B16-1
B12B16
B12B16-2
B12B15-1
B12B15
B12B15-2
B15B16-2
B15B16
B15B16-1
B13B15-2
B13B15
B13B15-1
230 kV
B12
B13
B15
B16-1
B16G
OVERHEAD TO TERMINAL STATION
795 kcmil, 26/7, ACSR, "DRAKE" minimum
B16
230 kV
B16T11
B16T12
B16T13
B16T14
T11
230/13.8 kV
T12
230/13.8 kV
T13
230/13.8 kV
T14
230/13.8 kV
SSTCT1
SSTCT2
SSTCT3
SSTCT4
13.8 kV
CT1T11
L11T11
CT2T12
L12T12
CT3T13
L13T13
CT4T14
L14T14
CT1
CT2
CT3
CT4
L11
L12
L13
L14
BS1L11
BS1L12
BS2L13
BS2L14
BS1
BS1BS2
BS2
TO 13.8/4.16 kV BLACK START T9
BS1T9
BS2T9
HOLYROOD TERMINAL STATION
NOMINAL 100 MW COMBUSTION TURBINE
MULTPILE UNITS - OPTION 2
newfoundland labrador
hydro
a nalcor energy company
SYS PLAN:
SYS OP:
ELEC:
P&C:
SHEET 1 OF 1
DATE: April 6, 2014
DRAWN BY: PWT
REVISION: 0
FILE: HRD CT opt i on 2 SKF

APPENDIX B

Preliminary Site Layout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APPENDIX C

Generation Planning Issues – November 2012 Report

GENERATION PLANNING ISSUES
NOVEMBER 2012

System Planning Department
November 2012

REGISTERED PROFESSIONAL ENGINEER
R. J. H. MOULTON
SIGNATURE
2012-11-14
DATE
PROVINCE OF NEWFOUNDLAND

newfoundland labrador
hydro
a nalcor energy company

Executive Summary

This report provides an overview of the Island Interconnected System (System) generation capability for the next 20 years, the proposed timing of the next requirement for additional generation supply, the resources available to meet that requirement, and identifies issues that need to be considered to ensure a decision on the preferred source can be made through an orderly and cost-effective process.

The long-term plan proposed in the Energy Plan is to replace the energy provided by the Holyrood Thermal Generating Station (HTGS) with electricity from the Lower Churchill development through a High Voltage Direct Current (HVdc) transmission link from Labrador to the island, known as the Labrador – Island Transmission Link (LIL). Currently, the generation source to be developed in Labrador is Muskrat Falls. In the event the Muskrat Falls Project (Muskrat Falls and the LIL) does not proceed, a supply future utilizing small hydro, wind and continued thermal based generation will be pursued. This requires Newfoundland and Labrador Hydro (Hydro) to maintain two generation expansion plans: one for the Muskrat Falls Project (Interconnected Island scenario) and one for the Isolated Island scenario.

Based on an examination of the System's existing capability, the 2012 Planning Load Forecasts (PLF), and the generation planning criteria the Island system can expect capacity deficits starting in 2015 under both the Interconnected Island and Isolated Island scenarios and energy deficits in 2019. Although final sanction to proceed with the Interconnected Island scenario at Decision Gate 3 (DG3) has not been determined, analysis leading to Decision Gate 3 indicates that the Interconnected Island scenario continues to be the preferred path with a CPW preference of $2.4 billion (2012$). A decision on final sanction at DG3 is expected in 2012.

The later than expected sanctioning for the Muskrat Falls Project (Interconnected Island scenario) has led to the situation where it will soon be necessary to seek approval regarding construction of a capacity source to meet the 2015 capacity deficit. The preferred option in either scenario for this capacity addition would be a 50 MW combustion turbine (CT).

The analysis in this report covers only an Interconnected Island scenario including Muskrat Falls and LIL and does not consider the potential Maritime Link interconnection to Nova Scotia. Analysis associated with this link will be completed at a later date.

It should be noted that while Hydro is closely monitoring potential emissions reductions regulations, the analysis presented does not model potential costs or credits under an environmental mitigation strategy such as a cap-and-trade system.

From a system planning point of view, the key issues for Hydro to deal with in the near term are:

- Maintaining two expansion plans – Hydro must be prepared for events that may delay the proposed Muskrat Falls Project or if the project is not sanctioned;
- HTGS End-of-Life –For the Isolated Island alternative Hydro must determine what is required to ensure the HTGS can be operated reliably until it is no longer required as a generating source;
- Government Emissions Reductions Initiatives – Hydro must remain vigilant in considering the impact that Government emissions reductions initiatives could have on production costing and future generation planning studies;
- Environmental impact considerations – Hydro must begin to consider the potential impact of delays in project scheduling for all new generation sources due to increased environmental assessments in the form of Environmental Impact Studies;
- Fuel displacement – Hydro must continue to pursue and develop projects and incorporate energy conservation activities that are technically and economically feasible to displace fuel at the HTGS;

- Industrial expansion and contraction – Hydro must continue to assess, as updated information is provided, the impacts of industrial activity, both positive and negative, on the System's capacity and firm energy balance;
- Resource Inventory – Hydro must ensure that it maintains a current inventory of resource options with sufficient concept, costs and schedules;
- Demand study as to provide confidence in overall project; and
- Reduction Initiatives – Hydro must continue to take into account the consideration of demand reduction initiatives through demand management programs and rate design.

Table of Contents

1.0 Introduction

This report addresses the timing of the next requirement for additional generation supply under both the Interconnected Island and the Isolated Island options and the resources available to meet that requirement. The report also identifies those issues that need to be addressed to ensure that a decision on the preferred source can be made through an orderly and cost-effective process.

In September 2007, the Provincial Government released its Energy Plan. The Energy Plan directed Hydro to evaluate two options to deal with environmental concerns at the Holyrood Thermal Generating Station (HTGS). The first option, the Interconnected Island scenario, was to replace electricity produced by HTGS with electricity from the Lower Churchill River development via a High Voltage Direct Current (HVdc) transmission link to the island. The second option, the Isolated Island scenario, was to maximize the use of wind, small hydro and energy efficiency programs to reduce the reliance on electricity produced by HTGS. These two options require significantly different strategies to implement and require the development of two separate, generation expansion plans to manage the near-term until a decision is made on which option will be pursued for future development.

The 2010 analysis indicated a $2.2 billion (2010$) preference for the Interconnected Island scenario and thus the project passed through Decision Gate 2 (DG2). Further detail on this is included in the following reports:

(1) *Independent Supply Decision Review – Navigant Consulting Ltd. – September 14, 2011*[1]

(2) *Nalcor's Submission to the Board of Commissioners of Public Utilities with respect to the Reference from the Lieutenant-Governor in Council on the Muskrat Falls Project – Nalcor Energy – November 10, 2011*[2]

(3) *Report on Two Generation Expansion Alternatives for the Island Interconnected Electrical System – Volumes 1 and 2 – Manitoba Hydro International – January 2012*[3]

[1] http://www.pub.nl.ca/applications/MuskratFalls2011/files/exhibits/Exhibit101.pdf
[2] http://www.pub.nl.ca/applications/MuskratFalls2011/submission.htm
[3] http://www.pub.nl.ca/applications/MuskratFalls2011/MHIreport.htm

Since that time, work has progressed towards DG3, which includes a refinement of the estimates from DG2. In the DG3 analysis the Interconnected Island scenario maintains a strong economic preference ($2.4 billion (2012$)) over the Isolated Island alternative.

The analysis to determine the least cost option excluded the Maritime-Island Transmission Link (MIL). Further analysis of the benefits to the island of the MIL interconnection will be provided at a later date.

2.0 Load Forecast

This review utilizes the 2012 Planning Load Forecast (PLF) as prepared by the Market Analysis section of Hydro's System Planning Department. Long-term load forecasts for the Province are prepared using Hydro's own electricity demand forecasting models that are conditioned by corresponding Provincial economic forecasts that are regularly prepared for Hydro by the Department of Finance, Government of Newfoundland and Labrador. For the 2012 review, distinct load forecasts were prepared for the Island's main electricity supply alternatives:

- Interconnected Island: the Labrador - Island transmission link option including the Muskrat Falls development.
- Isolated Island: the continued Island isolated supply option.

The load forecasts were distinguished by the supply prices for each alternative and by differences in provincial economic growth expectations with and without the Muskrat Falls Project.

Some of the more important assumptions respecting existing and incremental economic activity impacting electricity demand and supply futures are:

- Vale NL nickel processing facility at Long Harbour with initial connection in 2012 and commercial production occurring across the 2013[3] to 2014 period;
- Teck mining operations at Duck Pond continuing through 2014[4];
- Development of the Hebron oil field but no natural gas or further provincial oil developments;
- Stable population outlook with net in-migration offsetting natural population declines; and
- Gradual improvement in provincial fisheries across the forecast period.

[3] Amended 2002 Development Agreement, Vale Inco and the Government of Newfoundland and Labrador
[4] Teck 2011 Annual Report.

Growth rate summaries of the relevant high-level economic indicators for the province as forecast by the provincial Department of Finance are presented in Table 2-1.

Table 2-1

Provincial Economic Indicators – 2012 PLF				
		2011-2016	**2011-2021**	**2011-2031**
Adjusted Real GDP at Market Prices* (% Per Year)	Interconnected Island	1.0%	0.8%	0.8%
	Isolated Island	0.5%	0.8%	0.8%
Real Disposable Income (% Per Year)	Interconnected Island	1.4%	1.3%	1.2%
	Isolated Island	1.0%	1.2%	1.2%
Average Housing Starts (Number Per Year)	Interconnected Island	3075	2672	2115
	Isolated Island	2885	2600	2089
End of Period Population (‘000s)	Interconnected Island	517	513	513
	Isolated Island	511	510	512
*Adjusted GDP excludes income that will be earned by the non-resident owners of Provincial resource developments to better reflect growth in economic activity that generates income for local residents.				

Hydro is responsible for the generation planning for the System and that includes the power and energy supplied by Hydro’s customer-owned-generation resources in addition to Hydro’s bulk and retail electricity supply, including power purchases. The projected electricity growth rates for the System are presented in Table 2-2.

An important source of load growth for the utility sector on the Island continues to be the steady preference for electric water heating systems along with a majority preference for electric space heating across residential and commercial customers. For Hydro's existing industrial customers, a single newsprint mill and oil refinery operations are maintained with the Teck mine expected to operate through 2014. The Vale nickel processing facility is scheduled to be provided a transmission connection in 2012 with commercial production expected in the 2013 to 2014 time frame.

Table 2-2

Electricity Load Growth Summary – 2012 PLF				
		2011-2016	2011-2021	2011-2031
Utility[1]	Interconnected Island	1.8%	1.2%	1.2%
	Isolated Island	1.7%	1.1%	1.0%
Industrial[2]	Interconnected Island and Isolated Island	9.4%	4.6%	2.3%
Total	Interconnected Island	3.1%	1.8%	1.4%
	Isolated Island	3.0%	1.7%	1.2%

1. Utility load is the summation of Newfoundland Power and Hydro Rural.
2. Industrial load is the summation of Corner Brook Pulp and Paper, North Atlantic Refining, Teck, Vale and Praxair. Teck is forecast to operate through 2014.

Table 2-3 provides a summary of the 2012 PLF electric power and energy requirements for the System for the period 2012 to 2021. Similar long-term load projections are prepared for the Labrador Interconnected System and for Hydro's Isolated Systems to derive a Provincial electricity load forecast. Appendix A contains the longer term planning load forecasts that were used to complete the generation expansion analysis.

Table 2-3

Electricity Load Summary – 2012 Island PLF						
Interconnected Island	Utility[1]		Industrial[1]		Total System[2]	
	Maximum Demand (MW)	Firm Energy (GWh)	Maximum Demand (MW)	Firm Energy (GWh)	Maximum Demand (MW)	Firm Energy (GWh)
2012	1400	6408	193	1310	1581	7942
2013	1427	6565	219	1367	1632	8169
2014	1451	6637	257	1591	1691	8472
2015	1476	6720	256	1804	1721	8745
2016	1490	6794	259	1889	1736	8902
2017	1507	6816	260	1886	1755	8921
2018	1509	6805	260	1890	1757	8914
2019	1511	6840	260	1890	1760	8949
2020	1518	6906	260	1890	1766	9016
2021	1532	7002	260	1890	1781	9113
Isolated Island	Utility[1]		Industrial[1]		Total System[2]	
	Maximum Demand (MW)	Firm Energy (GWh)	Maximum Demand (MW)	Firm Energy (GWh)	Maximum Demand (MW)	Firm Energy (GWh)
2012	1400	6408	193	1310	1581	7942
2013	1427	6565	219	1367	1632	8169
2014	1451	6637	257	1591	1691	8472
2015	1476	6681	256	1804	1720	8705
2016	1483	6761	259	1889	1730	8870
2017	1502	6798	260	1886	1750	8903
2018	1503	6788	260	1890	1752	8903
2019	1507	6799	260	1890	1755	8914
2020	1510	6854	260	1890	1758	8970
2021	1522	6954	260	1890	1771	9071

Note: 1. Utility and Industrial demands are non-coincident peak demands.
2. Total System is the total Island Interconnected System and includes losses. Demands are coincident peak demands.

3.0 System Capability

Hydro is the primary supplier of system capability to the Island Interconnected System, accounting for 77 percent of its net capacity and 78 percent of its firm energy. In addition, Hydro also has a contract with the Government of Newfoundland and Labrador to operate and purchase energy from the generating facilities at Star Lake and on the Exploits River. Capability is also supplied by customer generation from Newfoundland Power Inc., and Corner Brook Pulp and Paper Limited (Kruger Inc.) Hydro also has contracts with two Non-Utility Generators (NUGs) for the supply of power and energy as well as contracts with two wind power projects that became operational in late 2008 and early 2009.

Hydroelectric generation accounts for 65 percent of the System's existing net capacity and firm energy capability. The remaining net capacity comes from wind farms and thermal resources. The thermal resources are made up of conventional steam, combustion turbine and diesel generation plants. Of the existing thermal capacity, approximately 73 percent is located at the HTGS and is fired using 0.7 percent sulphur No. 6 fuel oil. The remaining capacity is located at sites throughout the island. A complete breakdown of the System's existing capability is provided in Table 3-1.

Table 3-1

Island Interconnected System Capability – As of October 2012			
	Net Capacity [MW]	Energy [GWh]	
* - non-dispatchable (see Section 9.1)		Firm	Average
Newfoundland & Labrador Hydro			
Bay d'Espoir	592.0	2,272	2,588
Upper Salmon	84.0	492	540
Hinds Lake	75.0	290	341
Cat Arm	127.0	678	736
Granite Canal	40.0	191	238
Paradise River	8.0	33	41
Snook's, Venam's & Roddickton Mini Hydros	1.3	5	4
Total Hydraulic	927.3	3,961	4,488
Holyrood	465.5	2,996	2,996
Combustion Turbine	100.0	-	-
Hawke's Bay & St. Anthony Diesel	14.7	-	-
Total Thermal	580.2	2,996	2,996
Total NL Hydro	**1,507.5**	**6,957**	**7,484**
Newfoundland Power Inc.			
Hydraulic*	96.9	324	430
Combustion Turbine	36.5	-	-
Diesel	5.0	-	-
Total	138.4	324	430
Corner Brook Pulp and Paper Ltd.			
Hydraulic*	121.4	793	880
Star Lake and Exploits Generation			
Star Lake	15.0	87	144
Exploits	90.8	547	634
Total	105.8	634	778
Non-Utility Generators			
Corner Brook Cogen*	15.0	52	52
Rattle Brook*	4.0	13	15
St. Lawrence Wind*	27.0	92	105
Fermeuse Wind*	27.0	75	84
Total	73.0	232	256
Total Island Interconnected System	**1,946.1**	**8,940**	**9,828**

4.0 Planning Criteria

Hydro has established criteria related to the appropriate reliability for the System, at the generation level, that sets the timing of generation source additions. These criteria set the minimum level of reserve capacity and energy installed in the System to ensure an adequate supply for firm demand; however, short-term deficiencies can be tolerated if the deficiencies are of minimal incremental risk. As a general rule to guide Hydro's planning activities the following have been adopted:

Capacity: The Island Interconnected System should have sufficient generating capacity to satisfy a Loss of Load Hours (LOLH) expectation target of not more that 2.8 hours per year[5].

Energy: The Island Interconnected System should have sufficient generating capability to supply all of its firm energy requirements with firm system capability[6].

[5] LOLH is a statistical assessment of the risk that the System will not be capable of serving the System's firm load for all hours of the year. For Hydro, an LOLH expectation target of not more than 2.8 hours per year represents the inability to serve all firm load for no more than 2.8 hours in a given year.

[6] Firm capability for the hydroelectric resources is the firm energy capability of those resources under the most adverse three-year sequence of reservoir inflows occurring within the historical record. Firm capability for the thermal resources (HTGS) is based on energy capability adjusted for maintenance and forced outages.

5.0 Identification of Need

Table 5-1 presents an examination of the Interconnected Island and Isolated Island load forecasts compared to the planning criteria. It does not show uncommitted generation additions. In 2006, firm system capability was updated to reflect a 115 GWh increase in Hydro's hydroelectric-plant capability. This change was the result of a hydrology adjustment and the use of an integrated system model which determines a more accurate firm system capability. Previously, firm system capability was calculated using the summation of individual firm values provided by the design consultants of each facility.

Table 5-1 illustrates when supply capacity and firm capability will be outpaced by forecasted electricity demand under the two different expansion scenarios. The table shows that under both the Interconnected Island and Isolated Island scenarios, capacity deficits (LOLH exceeding 2.8 hours per year) start in 2015 and energy deficits in 2019. Since the closure of the pulp and paper mills in Stephenville and Grand Falls, capacity deficits now precede energy deficits indicating that the system is now capacity, rather than energy, constrained.

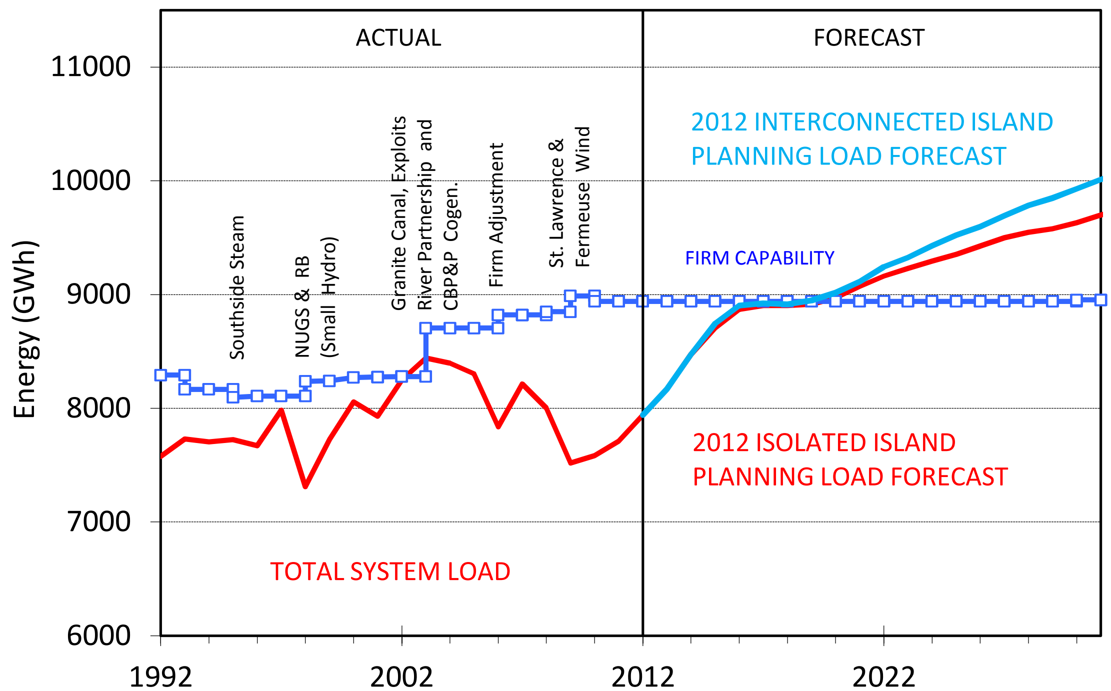
It should be noted that the capacity deficits trigger the need for the next generation source by late 2014 under the current planning criteria to avoid exceeding the LOLH limits in 2015.

Table 5-1 – Load Forecast Compared to Planning Criteria

Year	Load Forecasts				Existing System		LOLH (hr/year) (limit: 2.8)		Energy Balance (GWh)	
	Maximum Demand (MW)		Firm Energy (GWh)		Installed Net Capacity (MW)	Firm Capability (GWh)	Inter-connected Island	Isolated Island	Inter-connected Island	Isolated Island
	Inter-connected Island	Isolated Island	Inter-connected Island	Isolated Island						
2012	1,581	1,581	7,942	7,942	1,946	8,940	0.41	0.41	998	998
2013	1,632	1,632	8,169	8,169	1,946	8,940	0.97	0.97	771	771
2014	1,691	1,691	8,472	8,472	1,946	8,940	2.59	2.59	468	468
2015	1,721	1,720	8,745	8,705	1,946	8,940	4.57	4.39	195	235
2016	1,736	1,730	8,902	8,870	1,946	8,940	6.02	5.47	38	70
2017	1,755	1,750	8,921	8,903	1,946	8,940	7.59	7.07	19	37
2018	1,757	1,752	8,914	8,903	1,946	8,940	7.64	7.17	26	37
2019	1,760	1,755	8,949	8,914	1,946	8,940	8.09	7.52	(9)	(26)
2020	1,766	1,758	9,016	8,970	1,946	8,940	8.85	7.89	(76)	(30)
2021	1,781	1,771	9,113	9,071	1,946	8,940	11.34	9.97	(173)	(131)

Figure 5-1 presents a graphical representation of historical and forecasted load and system capability for the Interconnected Island and Isolated Island scenarios. It is a visual representation of the energy balance shown in Table 5-1.

Figure 5-1
Island Interconnected System Capability vs. Load Forecast



6.0 Near-Term Resource Options

This section presents a summary of identified near-term generation expansion options. It represents Hydro's current portfolio of alternatives that were screened and may be considered to fulfill future generation expansion requirements. Included is a brief project description as well as discussion surrounding project schedules, the basis for capital cost estimates, issues of bringing an alternative into service, and other issues related to generation expansion analysis.

In Nalcor's submission to the Board, *Nalcor's Submission to the Board of Commissioners of Public Utilities with respect to the Reference from the Lieutenant-Governor in Council on the Muskrat Falls Project – Nalcor Energy - November 10th, 2011*[7], other options and fuel sources that have been considered and screened out were discussed. As a result, they have not been included in this analysis.

6.1 Island Pond

Island Pond is a proposed 36 MW hydroelectric project located on the North Salmon River, within the watershed of the existing Bay d'Espoir development. The project would utilize approximately 25 metres of net head between the existing Meelpaeg Reservoir and Crooked Lake to produce an annual firm and average energy capability of 172 GWh and 186 GWh, respectively.

The development would include the construction of a three kilometre diversion canal between Meelpaeg Reservoir and Island Pond, which would raise the water level in Island Pond to that of the Meelpaeg Reservoir. Also, approximately 3.4 kilometres of channel improvements would be constructed in the area. At the south end of Island Pond, a 750 metre long forebay would pass water to the 23 metre high earth dam, then onto the intake and powerhouse, finally

[7] http://www.pub.nl.ca/applications/MuskratFalls2011/submission.htm

discharging it into Crooked Lake via a 550 metre long tailrace. The electricity would be produced by one 36 MW Kaplan turbine and generator assembly.

The facility would be connected to TL263, a nearby 230 kV transmission line connecting the Granite Canal Generating Station with the Upper Salmon Generating Station.

Schedule and Cost Estimate Basis

To ensure that Hydro is in a position to properly evaluate Island Pond, an outside consultant was commissioned to prepare a final-feasibility level study and estimate. The final report, *Studies for Island Pond Hydroelectric Project*, was presented to Hydro in December 2006. The report prepared a construction ready update report including an updated capital cost estimate and construction schedule. In the absence of any further work beyond what was identified, the overall schedule is estimated to be approximately 42 months from the project release date to the in-service date. In 2012, these costs were brought to 2012 dollars, using appropriate escalation rates and updated costs, where required (*Portland Creek and Island Pond Hydroelectric Projects – Update Cost Estimates – SNC-Lavalin – June 2012*).

6.2 Portland Creek

Portland Creek is a proposed 23 MW hydroelectric project located on Main Port Brook, near Daniel’s Harbour, on the Northern Peninsula. The project would utilize approximately 395 metres of net head between the head pond and outlet of Main Port Brook to produce an annual firm and average energy capability of 99 GWh and 142 GWh, respectively.
The project would require: a 320 metre long diversion canal; three concrete dams; a 2,900 metre penstock; a 27 kilometre 66 kV transmission line from the project site to Peter’s Barren Terminal Station; and the construction of access roads. The electricity would be produced by two 11.5 MW Pelton turbine and generator assemblies.

Schedule and Cost Estimate Basis

The current schedule and capital cost estimate for Portland Creek is based on a January 2007 feasibility study, *Feasibility Study for: Portland Creek Hydroelectric Project*, prepared for Hydro by outside consultants. The proposed construction schedule indicates a construction period of 32 months from the project release date to the in-service date. The main activities that dictate the schedule are the construction of access roads and the procurement of the turbine and generator units. In 2012, these costs were brought to 2012 dollars, using appropriate escalation rates and updated costs, where required (*Portland Creek and Island Pond Hydroelectric Projects – Update Cost Estimates – SNC-Lavalin – June 2012*).

6.3 Round Pond

Round Pond is a proposed 18 MW hydroelectric project located within the watershed of the existing Bay d'Espoir development. The project would utilize the available net head between the existing Godaleich Pond and Long Pond Reservoir to produce an annual firm and average energy capability of 108 GWh and 139 GWh, respectively.

Schedule and Cost Estimate Basis

The current schedule and capital cost estimate for Round Pond is based on the 1988 feasibility study, *Round Pond Hydroelectric Development*, prepared for Hydro by outside consultants, and the associated 1989 Summary Report based on the same. In the absence of any further work beyond what was identified in this study, the overall program for the Round Pond development is estimated to be completed in 33 months, including detailed engineering design. The period for site works includes two winter seasons during which construction activities can be expected to be curtailed. Work on transmission line, telecontrol and terminal equipment would be incorporated in this schedule. In 2012, these costs were brought to 2012 dollars, using appropriate escalation rates and updated costs, where required (*Round Pond Hydroelectric Development – Update of the 1988 Cost Estimate – Hatch – May 2012*).

6.4 Wind Generation Projects

The island of Newfoundland has a world-class wind resource with many sites exhibiting excellent potential for wind-power development. Despite this, there are a number of operational constraints that limit the amount of additional non-dispatchable generation that can be accepted into the System. In January 2007, Hydro signed its first power purchase agreement (PPA) for 27 MW of wind power located at St. Lawrence. In December 2007, it signed a second PPA for another 27 MW of wind power located at Fermeuse. Both of these projects are currently generating power into the island grid. Based on analysis completed by Hydro in 2004 and documented in the report titled: *An Assessment of Limitations For Non- Dispatchable Generation On the Newfoundland Island System – Newfoundland and Labrador Hydro – October 2004*[8], the maximum allowable wind generation on the Isolated Island system had been limited to 80 MW.

In 2012 Hydro completed an internal study titled: *Wind Integration Study-Isolated Island: Technical Study of Voltage Regulation and System Stability – Newfoundland and Labrador Hydro – August 18, 2012*[9]. This study updated the technical analysis completed in 2004 and established new technical wind integration limits. Hatch consultants were then contracted to complete a study titled: *Wind Integration Study – Isolated Island – Hatch – August 7, 2012*[10] to assess how much additional non-dispatchable wind generation could be added, economically and technically to the Island power system. Hatch completed a review of Hydro's technical analysis as well as a detailed hydrology assessment that aided in their recommendation.

The Hatch study concludes that a total wind generation penetration by the year 2035 of approximately 300 MW yielding a 10 percent energy penetration is consistent with a high penetration in isolated power systems. The 10 percent energy penetration can be achieved through the addition of 225 MW of new wind generation in addition to the existing 54 MW of

[8] http://www.pub.nl.ca/applications/MuskratFalls2011/files/exhibits/Exhibit61.pdf
[9] http://powerinourhands.ca/pdf/WindIntegration.pdf
[10] http://powerinourhands.ca/pdf/HatchWindIntegrationStudy.pdf

installed capacity. This new generation has been added to the Isolated Island expansion in the following increments:

- 2015 50 MW
- 2020 50 MW
- 2025 50 MW
- 2030 50 MW
- 2035 25 MW

Additional wind was not incorporated in the Interconnected Island case. However, wind could be built for export and this option will be analysed at a later date.

Schedule and Cost Estimate Basis

Wind projects typically require at least six to eight months of site-specific environmental monitoring to adequately define the resource. Project development, environmental review and feasibility studies for attractive sites are typically initiated concurrent with the resource study and are finalized shortly after completing the resource assessment. The final design and construction for a wind farm could be completed over an additional 12 to 18 months. The overall project schedule is approximately 30 months from the project release date to the in-service date. Additional time may be required, depending on market conditions, to secure turbine delivery. Cost estimates were reviewed in 2012 and found to be consistent with current industry estimates.

6.5 Combined Cycle Plant

The combined cycle facility, also known as a combined-cycle combustion turbine (CCCT) facility, consists of a combustion turbine fired on No. 2 diesel fuel, a heat recovery steam generator, and a steam turbine generator.

Two alternative sites are being considered. One alternative calls for a proposed combined-cycle plant to be located at the existing HTGS to take advantage of the operational and capital cost savings associated with sharing existing facilities. The other alternative is to develop a greenfield site at a location that has yet to be determined. The greenfield alternative may be preferred due to environmental constraints that may be placed on any new developments at Holyrood and the reduced risk of loss of multiple generation sources in the event of major events.

In either alternative, the power rating being considered is a 170 MW (net) CCCT facility. The annual firm energy capability is estimated at 1,340 GWh for the 170 MW unit.

Schedule and Cost Estimate Basis

It is expected that a combined-cycle plant would require an Environmental Preview Report (EPR) with the guidelines for its preparation similar to the 1997 review of the proposed Holyrood Combined Cycle Plant. The overall project schedule is estimated to be at least 36 months from the project release date to the in-service date.

The capital cost estimate for each power rating of the Holyrood Combined Cycle Plant was based on the 2012 update (*Newfoundland and Labrador Hydro – 170 MW CCCT and 50 MW CT Facilities – High Level Cost Estimates and Schedules – Hatch – May 2012*) of the *Combined Cycle Plant Study Update, Supplementary Report – Acres International* which was completed in November 2001.

6.6 Combustion Turbine Units

These nominal 50 MW (net), simple-cycle combustion turbines (CT) would be located either adjacent to similar existing units at Hydro's Hardwoods and Stephenville Terminal Stations, at the Holyrood site or at greenfield locations. They are fired on diesel fuel and due to their modest efficiency relative to a CCCT plant, they are primarily deployed for peaking and voltage support functions but, if required, can be utilized provide an annual firm energy capability of 394 GWh each.

Schedule and Cost Estimate Basis

It is anticipated an EPR would be required for each proposed CT project. The overall project schedule is estimated to be at least 36 months from the project release date to the in-service date.
The capital cost estimate for the 50 MW CT is based on the *Newfoundland and Labrador Hydro – 170 MW CCCT and 50 MW CT Facilities – High Level Cost Estimates and Schedules – Hatch – May 2012*).

6.7 Muskrat Falls Project (Labrador – Island Transmission Link)

Development of the Muskrat Falls Project would include:

- the 824 MW capacity Muskrat Falls generating facility with interconnecting HVac transmission facilities between Muskrat Falls and Churchill Falls; and
- the Labrador-Island Transmission HVdc Link and associated island system upgrades.

Schedule and Cost Estimate Basis

It is expected that this project would be completed in 2017.

A summary of the capital cost estimate for this project is available in the backgrounder: *Capital Cost Summary DG2 to DG3 – Government of Newfoundland and Labrador – November 2012*[11]

[11] http://www.powerinourhands.ca/pdf/Capital Cost and CPW Summary.pdf

A more complete description can be found in Nalcor's submission to the Board, (*Nalcor's Submission to the Board of Commissioners of Public Utilities with respect to the Reference from the Lieutenant-Governor in Council on the Muskrat Falls Project – Volume 2 - Nalcor Energy - November 10th, 2011*)[12] and *Review of the Muskrat Falls and Labrador Island HVdc Link and the Isolated Island Options – Manitoba Hydro International – October 2012*[13]

[12] http://www.pub.nl.ca/applications/MuskratFalls2011/submission.htm
[13] http://www.powerinourhands.ca/pdf/MHI.pdf

7.0 Preliminary Generation Expansion Analysis

To provide an indication of the timing and scale of future resource additions required over the load forecast horizon, Hydro uses *Ventyx Strategist®* software to analyse and plan the generation requirements of the System for a given load forecast. *Strategist®* is an integrated, strategic planning computer model that performs, amongst other functions, generation system reliability analysis, projection of costs simulation and generation expansion planning analysis.

In the Province's Energy Plan, Hydro was directed to pursue one of two options for dealing with environmental concerns related to the HTGS. The first option was based on replacing the HTGS with energy from the Muskrat Falls development via an HVdc link to the Island. The second option was based on an isolated island system, similar to present day operations, but the HTGS environmental concerns of sulphur dioxide (SO_2) and particulate emissions will be addressed via the addition of scrubbers and electrostatic precipitators. The scrubbers and electrostatic precipitators will not address greenhouse gas issues. These two options have been named for the purposes of this report as the Interconnected Island scenario and the Isolated Island scenario.

These expansion plan scenarios represent Hydro's preferred path, utilizing resources from the identified portfolio.

The generation expansion analysis uses a 7.00 percent discount rate with all costs modeled in current (as spent) Canadian dollars, and the results discounted to the base year of 2012.

Based on the study assumptions outlined previously, the least-cost[14] generation expansion plans, under the two scenarios, is shown in Table 7-1 and graphically in Figures 7-1 and 7-2. Currently, the least-cost expansion plan is the one based on the Interconnected Island Scenario, which has a CPW preference of $2.4 billion (2012$) over the Isolated Island scenario.

7.1 Interconnected Island Scenario

Under the Interconnected Island scenario, a 50 MW CT would be completed in 2015. This will result in a slight violation of Hydro's reliability criteria in the winter of 2014 -15. The current schedule would see the Labrador – Island Transmission Link (LIL) in operation in 2017 and this would provide Hydro's system capability requirements beyond the horizon of this expansion analysis. Hydro would purchase energy from the Muskrat Falls Project through contract arrangements with Nalcor. As well, the existing 50 MW CTs at Hardwoods and Stephenville would be retired in 2025 and 2028, respectively. Holyrood would operate in a synchronous condenser mode after the LIL came in service. As well, it would provide backup generation capability until 2021, after which the steam portion of the plant would be retired.

7.2 Isolated Island Scenario

If the Muskrat Falls Project is not sanctioned, the Island will remain isolated from the North American grid. Under the Isolated Island scenario, the third and fourth 25 MW wind projects would be planned for 2015, in the same time frame the additional load from the Vale Inco NL facility is forecast to come on to the grid, enabling the grid to absorb more non-dispatchable generation. Wind projects are considered due to the benefits of fuel displacement and emissions reductions at the HTGS.

[14] For Hydro, the term "least-cost" refers to the lowest Cumulative Present Worth (CPW) of all capital and operating costs associated with a particular incremental supply source (or portfolio of resources) over its useful economic life, versus competing alternatives or portfolios. CPW concerns itself only with the expenditure side of the financial equation. The lower the CPW, the lower the revenue requirement for the utility and hence, the lower the electricity rates will be. By contrast, the term Net Present Value (NPV) typically refers to a present value taking into account both the expenditure and revenue side of the financial equation, where capital and operating expenditures are negative and revenue is positive. The alternative with the higher NPV has the greater return for the investor.

The next supply options in the least-cost generation expansion scenario are the indigenous hydroelectric plants of Island Pond in 2017, Portland Creek in 2019, and Round Pond in 2021 followed by one 50 MW CT in 2024 and two 50 MW CTs in 2025. As well, 50 MW of wind would be added in each of 2020, 2025 and 2030. For the Isolated Island scenario, further additions of thermal plants and wind can be expected post 2031.

Many of Hydro's assets are nearing their expected end-of-life and it is important to point out that under both expansion plans, the 54 MW combustion turbines located at Hardwoods and Stephenville are scheduled to retire during the study period (Hardwoods in 2025 and Stephenville in 2028).

While the expansion plans are indicative of the scale of future requirements, any final decision on resource additions will be made at an appropriate time in the future following a full review and allowing time for proper implementation. These, and other issues, are discussed further in the following section.

Table 7-1

2012 Generation Expansion Plans (Preliminary)		
Year	**Interconnected Island Scenario Hydro's Alternatives (Capacity/Firm Capability)**	**Isolated Island Scenario Hydro's Alternatives (Capacity/Firm Capability)**
2012		
2013		
2014		
2015	CT (50 MW/394 GWh)	CT (50MW/394 GWh) Wind Farm (25 MW/77 GWh) Wind Farm – PPA (25 MW/77 GWh)
2016		
2017	HVdc link (823 MW)	Island Pond (36MW/172 GWh)
2018		
2019		Portland Creek (23 MW/99 GWh)
2020		Wind Farm (2x25 MW/2x77 GWh)
2021		Round Pond (18 MW/108 GWh)
2022		
2023		
2024		CT (50 MW/394 GWh)
2025	Hardwoods CT retired	Wind Farms (2x25 MW/2x77 GWh) CT (2x50 MW/2x394 GWh) Hardwoods CT Retired
2026		
2027		
2028	Stephenville CT Retired	CT (50 MW/394 GWh) Stephenville CT Retired
2029		CT (50 MW/394 GWh)
2030		Wind Farms (2x25 MW/2x77 GWh)
2031		
Note: The HVdc link expansion plan satisfies Hydro's generation planning criteria well beyond the 2031 planning horizon. However, the Isolated Island expansion plan will require further additions as HTGS units are retired beginning in 2033 (estimated).		

Figure 7-1
Preliminary Interconnected Island Expansion Plan vs. Load Forecast

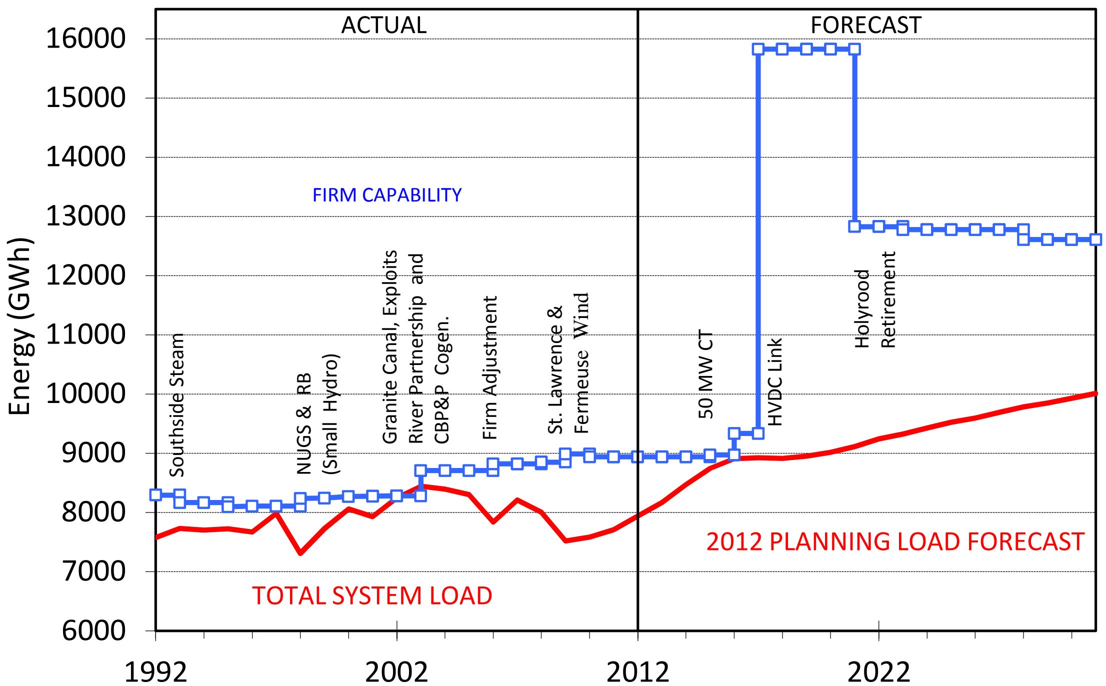
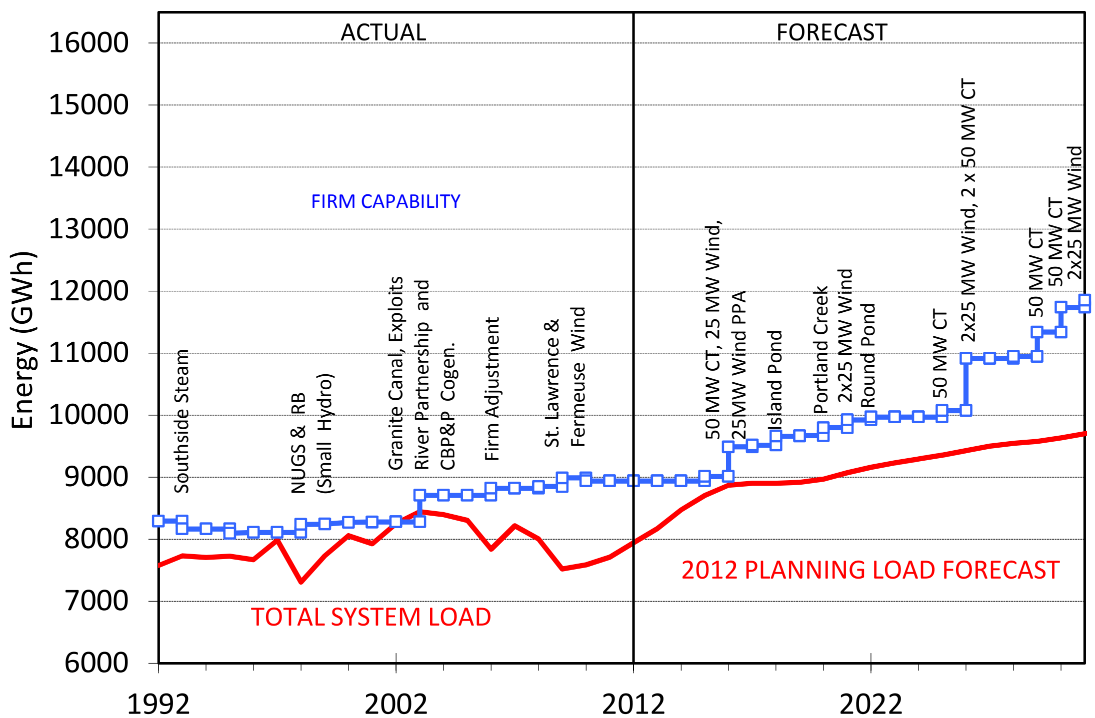


Figure 7-2
Preliminary Isolated Island Expansion Plan vs. Load Forecast



8.0 Timing of Next Decision

The later than expected sanctioning date for the Muskrat Falls Project (Interconnected Island scenario) at DG3 has led to the situation where it will soon be necessary to seek approval regarding construction of a capacity source to meet the 2015 capacity deficit. The preferred option in either scenario for this capacity addition would be a 50 MW combustion turbine (CT). Following the sanction decision, there should be clarity as to which expansion plan will be pursued to meet future island load requirements.

9.0 Other Issues

This section summarizes some of the issues which were considered when developing the preferred expansion plans.

9.1 Intermittent and Non-Dispatchable Resources

Based on the island's existing plus committed generating capacity, approximately 291 MW, or 15 percent of net capacity can be characterized as non-dispatchable generation (see Table 3-1). While energy production from these resources is predictable over the long term, the generation may not be available when needed. The concern with this type of generation comes on two fronts; first in the availability of the generation to meet higher loads; and second on occasions of light load when the non-dispatchable capacity can no longer be absorbed into the system without adverse technical and economic impacts.

From a generation planning point of view, when assessing the adequacy of system resources to meet peak demands, the characteristics of non-dispatchable generation are incorporated into the unit models. Therefore, on a go-forward basis, new non-dispatchable resources are appropriately evaluated in generation capacity planning analyses.

However, long-term generation planning may not necessarily capture the short-term operational constraints of intermittent and non-dispatchable resources, particularly those related to the ability of the system to absorb the capacity under light load periods. As more and more intermittent and non-dispatchable capacity is added to the system, there comes a point at which the ability to maintain stability and acceptable voltages throughout the system may be compromised. As well, there is an increased risk of spilling during high inflow periods as hydraulic production is reduced to accept non-dispatchable production.

As noted in Section 6.4, Hydro recently commissioned Hatch to complete a study to determine the amount of wind that could be incorporated into the Isolated System over the next 25 to 30 years. The recommendations of the Hatch study have been incorporated in the Isolated Island expansion analysis.

9.2 Environmental Considerations

Known environmental costs, such as environmental mitigation and monitoring measures that may be identified under the Environmental Assessment Act, and the current Provincial Government limitation of 25,000 tonnes per year for SO_2 emissions from the HTGS (this limit cannot be exceeded burning 0.7 percent sulphur fuel at Holyrood), have traditionally been included in generation planning studies. In 2007, the Provincial Energy Plan communicated that Hydro would deal with environmental emissions concerns at the HTGS either by pursuing the development of the Muskrat Falls River and a HVdc link to the Island, or by installing capital intensive environmental mitigation technologies in the form of scrubbers and electrostatic precipitators to control emissions at the HTGS.

In 2006, Hydro began burning one percent sulphur No. 6 fuel oil for the HTGS. While there can be additional purchase costs for one percent sulphur over two percent sulphur fuel oil, this improvement in fuel grade has reduced SO_2 and other emissions by about 50 percent. In 2009, Hydro switched to 0.7 percent sulphur fuel, which may reduce SO_2 and other emissions by a further 30 percent.

There remains considerable potential for other Government-led environmental initiatives (such as the Clean Air Act, cap-and-trade systems, carbon taxes, etc.) that can impact utility decision-making. While it is impossible to predict the exact nature of future emissions controls or other environmental programs, and their resulting costs, it is necessary to be aware of the issue.

The most prominent environmental issue currently under consideration is greenhouse gases and their impact on global warming. Carbon dioxide (CO_2) is the primary greenhouse gas of concern and Hydro's Holyrood Plant emits an average of approximately 808,000 tonnes per year[15] of CO_2. In the absence of a transmission link from Labrador to the Island, the long-term incremental energy supply for the island is very likely to be thermal-based and thus this issue could have a significant impact on production costing and future generation planning decisions.

For example, under a cap-and-trade system, the amount of effluent, such as CO_2, Hydro could be permitted to emit could potentially be capped by a regulator at a certain level. To exceed this level, credits could perhaps be purchased from a market-based system at a price set by the market. Conversely, surplus credits for effluent not emitted under the cap level might be traded on the market to generate revenue. This type of system could have significant impacts on Hydro's production costing and the cost of electricity, especially under the Isolated Island scenario.

Other emissions that may come under further regulation include nitrogen oxides (NO_x) and particulate.

[15] Based on the 5-year average of 808,000 tonnes per year of CO_2 from 2007 through 2011.

Hydro maintains a base of knowledge to be able to provide a qualitative level of analysis on the potential consequences of environmental initiatives such as this on resource decisions. As well, Hydro is closely monitoring national and international activity in this area.

9.3 Holyrood Thermal Generating Station End-of-Life

Units 1 and 2 of the HTGS were commissioned in 1971 and Unit 3 was commissioned in 1979. Under an Isolated Island future, the energy these units will be required to produce will be approaching their firm capability. Under an Interconnected Island future, these units will be required to provide system voltage support as well as to provide a backup supply for some period after the LIL comes in-service. Due to the age of these assets, significant capital investments may be required to ensure that they are capable of operating reliably until their anticipated end of life. Typically, as thermal plants age they are derated to account for their decreasing reliability caused by increasing failure rates of aging components. Under an Isolated Island scenario, Hydro cannot derate these units without adding additional generation sources.

Although final sanction to proceed with the Interconnected Island scenario at Decision Gate 3 (DG3) has not been given, analysis leading to DG 3 has indicated that the Interconnected Island scenario continues to be the preferred path. A decision on final sanction at DG3 is expected later in 2012. To this end, Hydro has been concentrating on condition assessments and the formulation of requirements to get Holyrood to the end of its life as a generating facility, several years after the LIL comes in-service, and to operate in synchronous condenser mode from LIL in-service.

9.4 Energy Conservation

The takeCHARGE portfolio of programs for residential customers has been operating since 2009 with increased participation in 2011 from previous years with continued rebates for several energy efficiency products for eligible residential customers. Commercial incentives were launched in 2010, offering price reduction of more efficient lighting products through lighting product distributors. The commercial lighting program has also experienced growth in participation since launch. The Industrial Energy Efficiency Program (IEEP) was launched in 2010 and targets Hydro's transmission level customers with incentives for custom projects to address their unique issues. Program participation has been slow but the first project was completed in 2011 with other proposed projects progressing through various stages from engineering feasibility to commissioning. Additional projects are expected to be completed in 2012.

In addition to the joint utility portfolio, Hydro has taken steps to implement additional efficiency programs. In 2010/11, Hydro piloted a program enabling consumers to purchase a wider range of smaller efficient household products and also provided information to customers to educate them about finding new ways to conserve. As well in 2009 and in 2011 Hydro partnered with the Provincial Department of Natural Resources to deliver a community based energy efficiency program in several Coastal Labrador communities. These pilot projects were undertaken to explore the impact of community based interventions on energy efficiency. Based on the experience gained from these pilot programs, Hydro has recently launched a three year direct install program for all isolated systems providing a host of initiatives for existing residential customers as well as providing information and low cost technologies for installation by commercial customers. Supplementing this isolated systems program is a custom program for commercial customers. In addition to the rebate programs, work continues on outreach and awareness efforts with customers, retailers and builders to ensure participation in the programs.

In September, an updated Five year Conservation and Demand Management (CDM) plan, *Five-Year Energy Conservation Plan: 2012-2016*, was filed with the Board by Newfoundland Power as part of their General Rate Application. This continues the takeCHARGE joint utility effort and expands the existing portfolio of programs. The final design work will be completed and the programs implemented upon Board approval.

10.0 Conclusion

Based on an examination of the System's existing capability, and the generation planning criteria, the System can expect capacity deficits starting in 2015 and energy deficits in 2019 under both the Interconnected Island and Isolated Island scenarios.

Due to the direction given to Hydro under the Provincial Government's Energy Plan, two generation expansion plans are to be maintained until a sanction decision on the Muskrat Falls Project can be reached. These two expansion plans mainly differ based on the inclusion of an HVdc link (LIL) as an available alternative to meet the System's energy requirements. The decision for sanctioning for the Muskrat Falls Project is scheduled for late 2012 and at that time, the expansion scenario that Hydro will ultimately pursue will be known. However, analysis leading to DG3 has indicated that the Interconnected Island scenario remains the preferred path, with a CPW preference of $2.4 billion (2012$).

In the near term, approval will be sought regarding construction of a capacity source to meet the 2015 capacity deficit. The preferred option in either the Interconnected Island or the Isolated Island scenario for this capacity addition would be a 50 MW combustion turbine (CT).

The analysis in this report covers only an Interconnected Island scenario including Muskrat Falls and LIL. It does not consider the potential Maritime Link interconnection to Nova Scotia. Analysis associated with this link will be completed at a later date.

It should be noted that while Hydro is closely monitoring potential emissions reductions regulations, the analysis presented does not model potential costs or credits under an environmental mitigation strategy such as a cap-and-trade system.

The impact of energy conservation measures resulting from the *Five-Year Energy Conservation Plan: 2012-2016* will need to be evaluated to determine what, if any impact, it has on the decision for the next source. At this time, it is expected that the principal benefits will be the economic and environmental benefits of the reduced reliance on electricity produced at HTGS and that the timing for the next decision will be unaffected.

From a system planning point of view, the key issues for Hydro to deal with in the near term are:

- Maintaining two expansion plans – Hydro must be prepared if events delay the proposed Muskrat Falls Project or if the project is not sanctioned;
- HTGS End-of-Life – Hydro must determine what is required to ensure the HTGS can be operated reliably until it is no longer required as a generating source;
- Government Emissions Reductions Initiatives – Hydro must remain vigilant in considering the impact that Government emissions reductions initiatives could have on production costing and future generation planning studies;
- Environmental impact considerations – Hydro must begin to consider the potential impact of delays in project scheduling for all new generation sources due to increased environmental assessments in the form of Environmental Impact Studies;
- Fuel displacement – Hydro must continue to pursue and develop projects and incorporate energy conservation activities that are technically and economically feasible to displace fuel at the HTGS;
- Industrial expansion and contraction – Hydro must continue to assess, as updated information is provided, the impacts of industrial activity both positive and negative on the System's capacity and firm energy balance;
- Resource Inventory – Hydro must ensure that it maintains a current inventory of resource options with sufficient study as to provide confidence in overall project concept, costs and schedules.
- Reduction Initiatives – Hydro must continue to take into account the consideration of demand reduction initiatives through demand management programs and rate design.

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Appendix A

Table A-1
2012 Island Planning Load Forecast

	Interconnected Island Case		Isolated Island Case	
Year	Demand [MW]	Firm Energy [GWh]	Demand [MW]	Firm Energy [GWh]
2012	1581	7942	1581	7942
2013	1632	8169	1632	8169
2014	1691	8472	1691	8472
2015	1721	8745	1720	8705
2016	1736	8902	1730	8870
2017	1755	8921	1750	8903
2018	1757	8914	1752	8903
2019	1760	8949	1755	8914
2020	1766	9016	1758	8970
2021	1781	9113	1771	9071
2022	1801	9243	1790	9161
2023	1824	9325	1807	9230
2024	1841	9429	1821	9293
2025	1861	9522	1834	9353
2026	1879	9595	1848	9426
2027	1894	9692	1862	9498
2028	1912	9783	1875	9546
2029	1929	9848	1886	9579
2030	1942	9930	1894	9631
2031	1958	10012	1905	9700

APPENDIX D

Review of the Muskrat Falls and Labrador Island HVdc Link and the Isolated Island Options – October 2012 – Manitoba Hydro International

Manitoba HYDRO INTERNATIONAL

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Prepared for:
Hon. Jerome Kennedy, Q.C.
The Minister of the Department of Natural Resources
Government of Newfoundland and Labrador

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October 26, 2012

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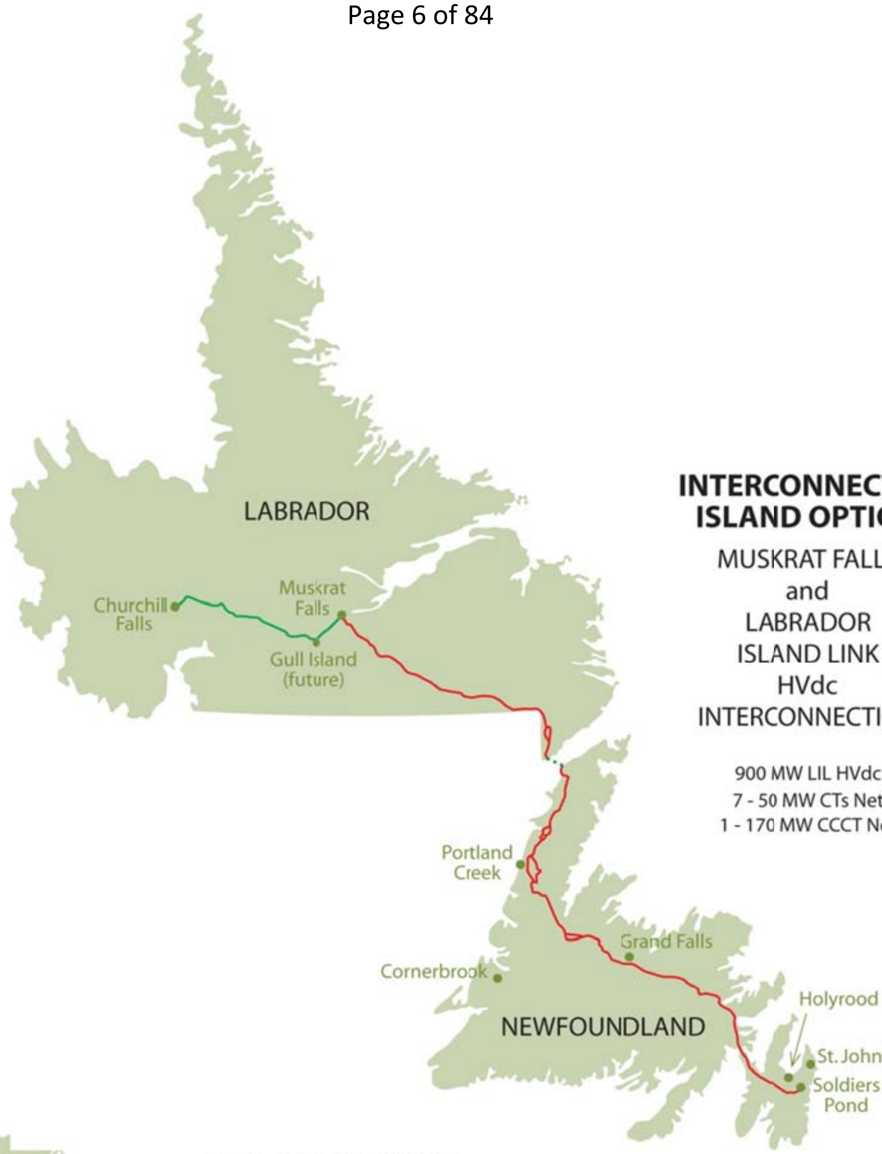
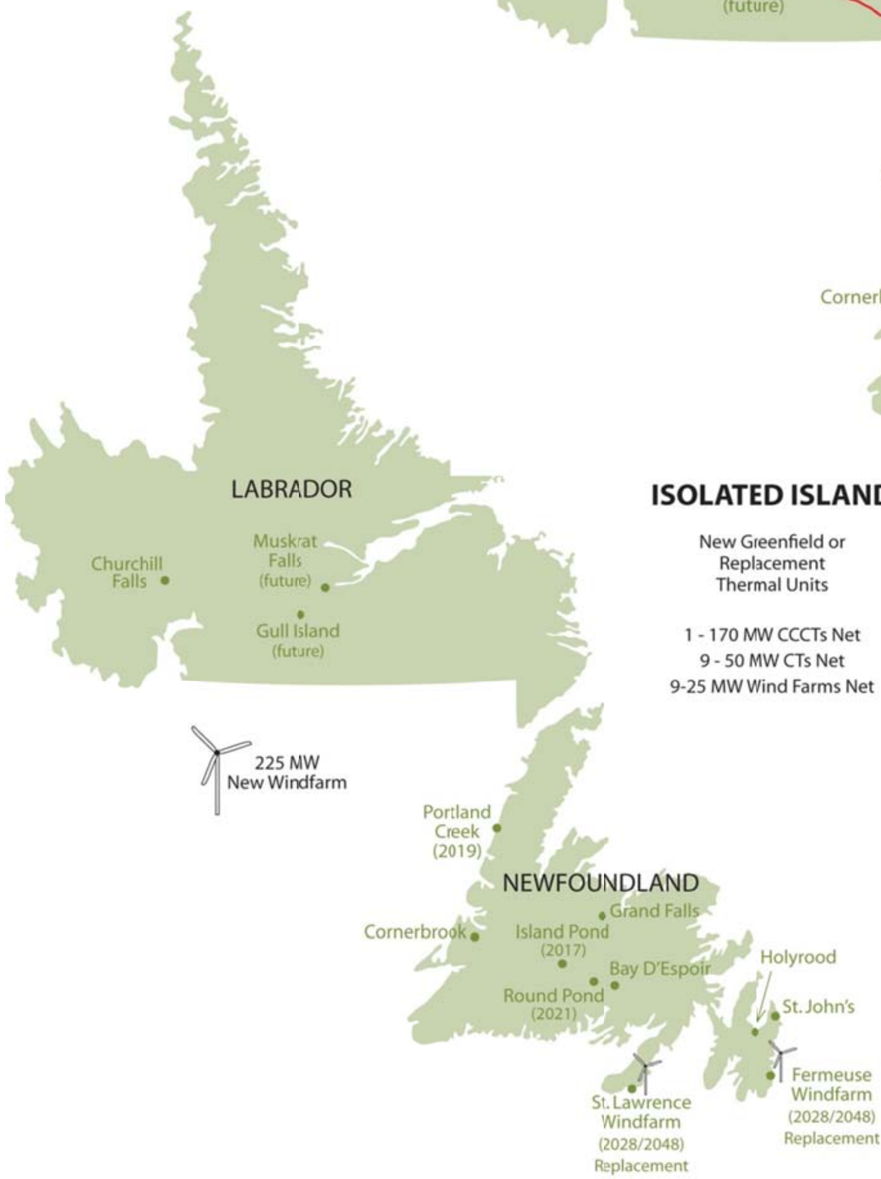


INTERCONNECTED ISLAND OPTION

MUSKRAT FALLS
and
LABRADOR
ISLAND LINK
HVdc
INTERCONNECTION

900 MW LIL HVdc
7 - 50 MW CTs Net
1 - 170 MW CCCT Net



ISOLATED ISLAND

New Greenfield or
Replacement
Thermal Units

1 - 170 MW CCCTs Net
9 - 50 MW CTs Net
9-25 MW Wind Farms Net

Executive Summary

The Government of Newfoundland and Labrador, retained Manitoba Hydro International Ltd. (MHI) to provide an independent assessment of two generation supply options, as prepared by Nalcor Energy (Nalcor) in preparation for Decision Gate 3, for the future supply of electricity to the Island of Newfoundland. MHI was asked to review the work completed by Nalcor Energy since Decision Gate 2 in preparation for Decision Gate 3 and to determine which option is the least cost based on the updated cost and technical data provided by Nalcor. MHI was also asked to complete a reasonableness assessment on all inputs into that analysis. The least cost metric for each option was computed by application of the cumulative present worth (CPW) method.

The CPW approach is an acceptable method by which to measure the present worth of alternative options. It focuses only on costs, including capital expenditures for the construction of new facilities, operating costs, fuel costs, financing costs and the cost of purchased power. The preferred option is the one with the lowest CPW outcome for the costs considered over the study horizon.

Manitoba Hydro International Ltd. (MHI) has reviewed the technical material and cumulative present worth estimates provided by Nalcor to MHI for two power supply options to serve the forecasted load in Newfoundland and Labrador until 2067.

One of the options, known as the Interconnected Island option because power would be fed to the Island of Newfoundland, is largely a hydroelectric generation plan, with 824 MW from a hydroelectric generating station and 670 MW from thermal generating stations. The thermal plants are largely used to provide reliability and capacity support to the system and are only used when operational contingencies arose. Power from Muskrat Falls Generating Station on the Lower Churchill in Labrador would be fed to Newfoundland over the Labrador Island Link HVdc transmission line that will cross the Strait of Belle Isle. The cumulative present worth (CPW) of the Interconnected Island option was estimated at $8,366 million in 2012 dollars, which includes the present worth of the capital costs ($6,202 million), operating and maintenance costs, fuel purchases, and power purchase agreement costs.

The other option, known as the Isolated Island option because all generation would originate in Newfoundland, is largely a thermal generation plan, with 1,890 MW from thermal generating stations, 77 MW from mini-hydroelectric generating stations, and 279 MW from wind farms. The CPW of the Isolated Island option was estimated at $10,778 million in 2012 dollars, including $6,706 million in fuel costs.

The current review of the options was based on material provided by Nalcor since November 2010 in preparation for Decision Gate 3, the milestone to give project sanction. To perform this review, MHI assembled a team of specialists with expertise in load forecasting, risk analysis, hydroelectric generation, HVdc engineering, system planning, and financial analysis. As part of the review process, team members met with Nalcor representatives and their consultants to review the new information available on the options.

Several key findings on Nalcor's work came to light during MHI's current review. They are highlighted here to help convey the depth and extent, and reasonableness, of the refinements made to the two options.

Key Findings

Interconnected Island Option

The Interconnected Island option for Decision Gate 3 has the following component mix: a 900 MW Labrador Island HVdc link, a total of ten 50 MW CTs (combustion turbines) installed of which three are replacements, and one 170 MW CCCT (combined cycle combustion turbines). There was some realignment of the generating station at Muskrat Falls as a result of detailed design modeling. Nalcor also specified the size of the synchronous condensers to support the Labrador Island Link HVdc system.

Load Forecast. The Load Forecast for the Interconnected Island option showed an increase in domestic load for the period to 2029, which was expected due to higher economic forecasts for personal disposable income and population. However, the general service sectors show a decrease, which would appear to be conservative as it normally mirrors domestic load. The industrial load does not include any new accounts over the entire time-span, which is very likely conservative. MHI finds that the Load Forecast for the Interconnected Island option is well founded and appropriate as an input into the Decision Gate 3 process.

AC Integration Studies. MHI's review of the ac integration studies for the Interconnected Island option indicates that Nalcor is in compliance with good utility practices. It also found that there is an opportunity, during detailed design, to optimize final configurations that may enhance system reliability.

HVdc Converter Stations. An assessment of the technical work completed by Nalcor and its consultants on the HVdc converter stations, electrode lines, and associated station equipment showed the work was reasonable as an input to the Decision Gate 3 process. MHI has notified Nalcor of some project improvements which could be made during the detailed design phase, with little impact on the CPW result.

HVdc Transmission Line, Electrode, and Collector System. MHI reviewed the cost estimates, construction schedules, and design methodologies undertaken by Nalcor and its consultants for the HVdc transmission line, electrode, and collector system. In MHI's opinion, Nalcor has used a diligent and appropriate approach in designing the transmission line to withstand many unique and severe climatic loading conditions along its length. MHI continues to support selection of a 1:150 year return-period due to the criticality of the HVdc transmission line to the Labrador and Newfoundland electrical system.

Strait of Belle Isle Crossing. MHI's review of the work completed by Nalcor and its consultants has shown that the design definition and concept of the configuration of the marine crossing are well founded. Further bathymetric work and a test borehole have shown that costs have increased only marginally. MHI considers that the marine crossing is viable, within the AACE Class 3 estimate range, and that it can be completed as planned within the allotted time frame.

Muskrat Falls Generating Station. The cost estimates, construction schedules, and design work undertaken by Nalcor and its consultants were reviewed as part of the Decision Gate 3 process. The proposed schedule is appropriate and consistent with best utility practices. Based on the amount of engineering completed and on the number of tenders for which estimates have been provided by potential suppliers, MHI considers the Decision Gate 3 cost estimate to be an AACE Class 3 and thus would be considered reasonable for a Decision Gate 3 project sanction. The Labrador transmission assets have also been appropriately designed and scheduled, and the cost estimate for them is consistent with good utility practice.

Isolated Island Option

The Isolated Island option, for Decision Gate 3, is comprised of the following generation resource mix of seven 170 MW CCCTs (net one new), fourteen 50 MW CTs (net 9 new), 77 MW of small hydroelectric plants, and 279 MW (net 225 MW new) of wind farms.

The load forecast for the Isolated Island option is somewhat less than the Interconnected Island option due to the higher marginal price of electricity. However, the general service sectors show a decrease, which would appear to be conservative as it normally mirrors domestic load. MHI finds that the Load Forecast for the Isolated Island is well founded and appropriate as an input into the Decision Gate 3 process.

Holyrood Thermal Generating Station. The Holyrood Thermal Generating Station is assumed to remain in full operation until 2036, with upgrades taking place as previously committed. Pollution control equipment was also scheduled to be installed by 2018. Vendors were canvassed for actual costs of equipment, and fuel oil prices were updated to reflect 2012 PIRA estimates.

The Holyrood Thermal Generating Station will be replaced with three 170 MW CCCTs, which are then subsequently replaced every 30 years. Estimates have been updated to reflect this change in operation.

Wind Farms. Wind farms are not deployed in the Interconnected Island option because surplus energy is available from Muskrat Falls Generation Station. In the Isolated Island option, a significant amount of wind power has been added, replacing a portion of the generation supplied by thermal generation operating on base load, as recommended in the external 2012 Hatch study.

MHI studied the proposed wind plan for inclusion into the Isolated Island option, as a separate project. The report for this study will be published under separate cover "Decision Gate 3 Review of the Wind Study for the Isolated Island of Newfoundland". The new generation master plan allows for up to 279 MW (including the existing 54 MW) of total wind capacity on the Island as part of the Isolated Island option.

MHI has reviewed the costs associated with the fixed charges and operating expenses of the wind farms used in the Isolated Island option. It finds them reasonable as inputs into the CPW analysis.

Simple and Combined Cycle Combustion Turbines

In the Interconnected Island option, there are ten 50 MW peaking units to match the increase in expected load, along with one 170 MW combined cycle unit. For Decision Gate 3, costs for the CCCT were upgraded for the analysis, with input from consultants and vendors.

The Isolated Island option is comprised of fourteen 50 MW CT peaking units with seven base-load 170 MW CCCT units, plus 225 MW of wind capacity. While there was no change in the types of units specified, there was an upgrade of costs to reflect current market prices.

Small Hydroelectric Plants

There are no changes in the configuration of any of the three small hydroelectric generating stations to be developed for the Isolated Island option. Island Pond Generating Station and Portland Creek Generating Station were updated to current costs, whereas additional work was undertaken on Round Pond Generating Station to update a 23-year-old study. The costs presented for all three plants are reasonable as AACE Class 4 estimates and suitable as input in the Decision Gate 3 analyses.

Financial Analysis of Options

Both the Interconnected Island and Isolated Island options have been updated to reflect current market conditions and cost inputs for the Decision Gate 3 analysis. The preference for the Interconnected Island option is $2.4 billion over the Isolated Island option. This work included a re-evaluation of fixed charges, operating costs, fuel costs, and power purchase costs. The cost estimates were conducted by consultants working with staff and management from Nalcor. Costs of both options have increased as a result of escalation and scope changes. With the assumptions and inputs provided by Nalcor to MHI, the Interconnected Island option remains the least cost option to meet the needs for capacity and energy to supply the forecasted load in Newfoundland and Labrador until 2067.

Comparison of CPW Estimates for the Two Supply Options

Major input category	Interconnected Island option		Isolated Island option		Difference
	CPW ($ 000s)	%	CPW ($ 000s)	%	
Fixed Charges	319,400	3.8	2,555,943	23.7	(2,236,543)
Operating Costs	258,939	3.1	752,448	7.0	(493,509)
Fuel	1,320,530	15.8	6,706,178	62.2	(5,385,648)
Power Purchases	6,467,127	77.3	763,770	7.1	5,703,357
TOTALS	**8,365,997**		**10,778,339**		**(2,412,342)**

It is important to note that any monetization of excess power from Muskrat Falls to external markets was not factored into MHI's Decision Gate 3 analysis; the monetization is expected to improve the overall business case of the Interconnected Island option. Also, any uncommitted energy from Muskrat Falls would allow Nalcor to more easily address any future large load additions to the Island of Newfoundland or to Labrador.

There remains significant uncertainty in fuel price forecasts, which are magnified over the 50-plus years of the study horizon. The Interconnected Island option has much less exposure to variances in fuel prices.

Conclusions

MHI has found Nalcor's work to be skilled, well-founded, and in accordance with industry practices. The result of the CPW analysis indicates a preference for the Interconnected Island option of $2.4 billion over the Isolated Island option. Both options have increased substantially in cost due to escalation and scope change from prior estimates released in November 2010. However, the Interconnected Island option continues to have a lower present value cost given the full range of sensitivity analyses and inputs provided by Nalcor. MHI therefore supports Nalcor's finding that the Interconnected Island option is the least-cost option of the two.

Nothing was found in any of the technical or financial reviews that would substantially change MHI's findings under the existing assumptions.

Although beyond the scope of the review, MHI also concluded that a planned new connection of Newfoundland's power system to the North American grid is not only expected to improve reliability of the province's system but also increase provincial power revenues, given that Muskrat Falls would generate more electricity than required by the province for the next two decades.

Recommendations

Given the analysis that MHI has conducted based on the data and reports provided by Nalcor, MHI recommends that Nalcor pursue the Interconnected Island option as the least cost alternative to meet future generation requirements to meet the expected electrical load in Newfoundland and Labrador.

Table of Contents

1 Introduction

The Government of Newfoundland and Labrador retained Manitoba Hydro International Ltd. (MHI) to provide an independent technical assessment of two generation supply options, as prepared by Nalcor Energy (Nalcor), for the future supply of electricity to the Island of Newfoundland. The two generation supply options are the Interconnected Island option and the Isolated Island option. The scope of this assessment is limited to Nalcor's revisions to the two generation supply options following Decision Gate 2 (DG2), from November, 2010. MHI's assessment is summarized in this current report, and will be used in preparation for Decision Gate 3 (DG3) or project sanction.

The Decision Gate process is a project management process designed to allow effective decision making for projects. Nalcor has passed the Decision Gate 2 milestone November 2010 and the next stage gate or Decision Gate 3 is the milestone to determine whether to proceed with the project. Decision Gate 3 is also referred to as project sanction.

MHI's report is preceded by a report prepared by the Newfoundland and Labrador Board of Commissioners of Public Utilities dated March 30, 2012[1]. The Board's report reviewed the two generation supply options for the Government of Newfoundland and Labrador to determine whether the Interconnected Island Option represented the least-cost option for the supply of power to the Island Interconnected customers over the period of 2011-2067 as compared with the Isolated Island option. The Board's report also embodied the work done by Manitoba Hydro International as their independent expert as part of the Decision Gate 2 review.

MHI's review of the work completed by Nalcor in preparation for Decision Gate 3 includes an assessment of the Cumulative Present Worth (CPW) analysis of the various components for each of the two options, including a reasonableness assessment of all inputs into that analysis. The tests of reasonableness for this assessment are generally defined as the work following:

- Good project management and execution practices
- Good utility practices of the majority of electrical utilities in Canada, while recognizing the unique electrical isolated system on the Island of Newfoundland and commonly accepted practice in Newfoundland and Labrador regarding the electrical system. Any practices unique to Newfoundland and Labrador are noted in this report. The review and technical assessment in the context of this scope of work determines if Nalcor's

[1] Board of Commissions of Public Utilities, "Reference to the Board – Review of Two Generation Expansion Options for the Least-Cost Supply of Power to Island Interconnected Customers for the Period 2011-2067", March 30, 2012.

work was undertaken in accordance with good utility practices whereby the processes, practices, and standards used in the development of the work follows generally acceptable practices, standards, and processes of a majority of the utilities in Canada.

A comparison of the two generation supply alternatives; the Interconnected Island option and the Isolated Island option, are outlined on pages 7 and 8 (Figure 1 and Figure 2).

Over the study period, the Interconnected Island option is largely a hydroelectric generation plan (824 MW from the Muskrat Falls Generating Station and the 900 MW Labrador-Island Link HVdc system, with the addition of 10 – 50 MW CTs and one 170 MW CCCT (520 MW net) of thermal generation for capacity reserve. Power from the Muskrat Falls Generating Station on the Lower Churchill River in Labrador is planned to be supplied to Newfoundland over the Labrador-Island Link HVdc system transmission line that would cross the Strait of Belle Isle. The target for first power from the Muskrat Falls Generating Station is scheduled to be available in July 2017.

Similarly, the Isolated Island option is largely a thermal generation plan (620 MW net), with the addition of 77 MW of small hydroelectric-generating stations and 225 MW net of new wind power. The generation plan includes:

- Installation of environmental emissions controls at Holyrood (electrostatic precipitators, scrubbers and NOx burners) as per the Newfoundland and Labrador Government's policy directives
- Life extension projects at Holyrood which is replaced by three 170 MW combined-cycle combustion turbines in 2032, 2033 and 2036.
- 23 – 25 MW, plus four 27 MW of wind farm (279 MW net)
- The 36 MW Island Pond Generating Station
- The 23 MW Portland Creek Generating Station
- The 18 MW Round Pond Generating Station
- Nine 50 MW combustion turbines (450 MW net)
- One 170 MW combined-cycle combustion turbine (170 MW net)

This review of the two generation supply options includes a more in-depth examination of the transmission line designs, ac integration studies, and HVdc converter station plans, as this material has been recently prepared for Decision Gate 3. MHI's focus for the Muskrat Falls Generating Station, the Strait of Belle Isle marine crossing, and thermal power plants was limited to a detailed review of cost estimates and schedule as it relates to the project definition. The technical comments contained in this report are offered for Nalcor's consideration based on review of the available material, meetings with Nalcor, and MHI's past experience on similar projects. Comments of a significant nature that could potentially lead to impacts on the result of the CPW analysis are highlighted; the balance of the comments are for Nalcor to consider as part of the detail design process post-Decision Gate 3.

For Decision Gate 3, the cost estimate accuracy range for all engineering estimates for the Muskrat Falls Generating Station and the Labrador-Island Link HVdc system was the Association for the Advancement of Cost Engineering (AACE), Class 3 estimate range. For the Isolated Island option, some costs were updated, whereas others were escalated to provide new base case numbers at the AACE Class 4 level similar to that used for Decision Gate 2.

This report is organized with the major elements of the Interconnected Island option being discussed first in Section 2. The items related to the Isolated Island option are discussed in Section 3, with the CPW financial analysis described in Section 4. A number of documents have been provided to MHI by Nalcor to assist in this review.

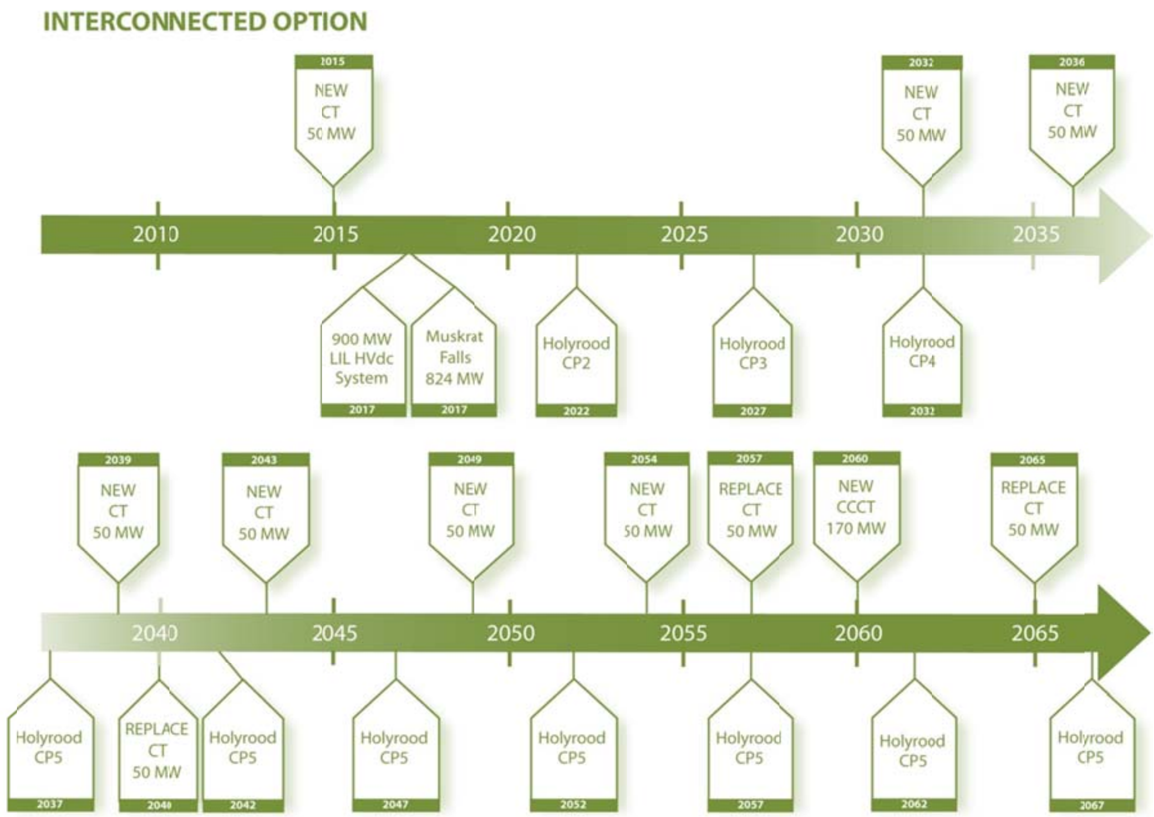


Figure 1: Project Time Line - Interconnected Island Option

The Interconnected Island option encompasses several generation items that are added to the system according to the generation master plan. These items and installation dates are shown in Figure 1. The timing and sizing of new generation sources are a result of the Strategist Software. This plan is essentially the same as the previously published plan with differences in plant timings. Holyrood sustaining capital for unit 3 synchronous condenser operation and plant decommissioning costs have been noted as Holyrood CP2 through 5.

The Isolated Island option as detailed in Section 3 encompasses several generation items that are added to the system according to the generation master plan. These items and installation dates are shown in Figure 2 below.

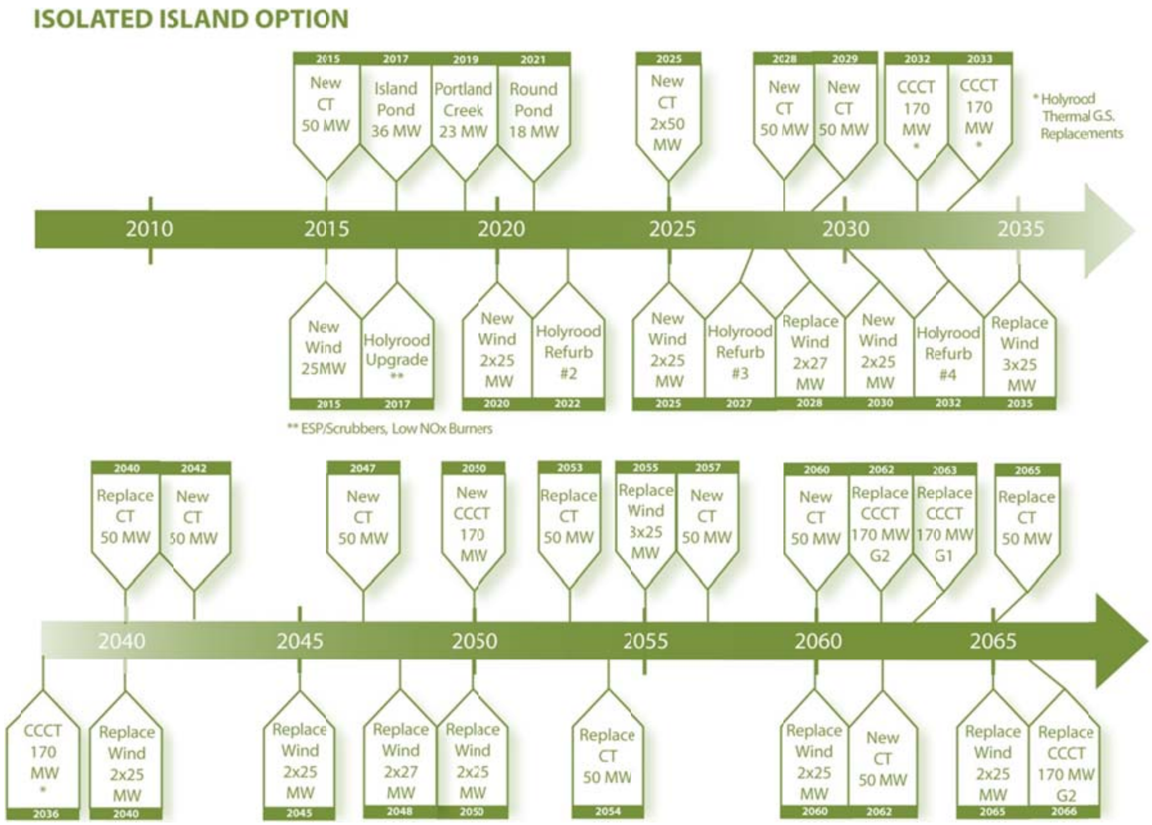


Figure 2: Project Time Line - Isolated Island Option

2 Interconnected Island Option

The Interconnected Island option is depicted in Figure 3 showing the HVdc transmission system, and important elements as part of the generation resource plan.

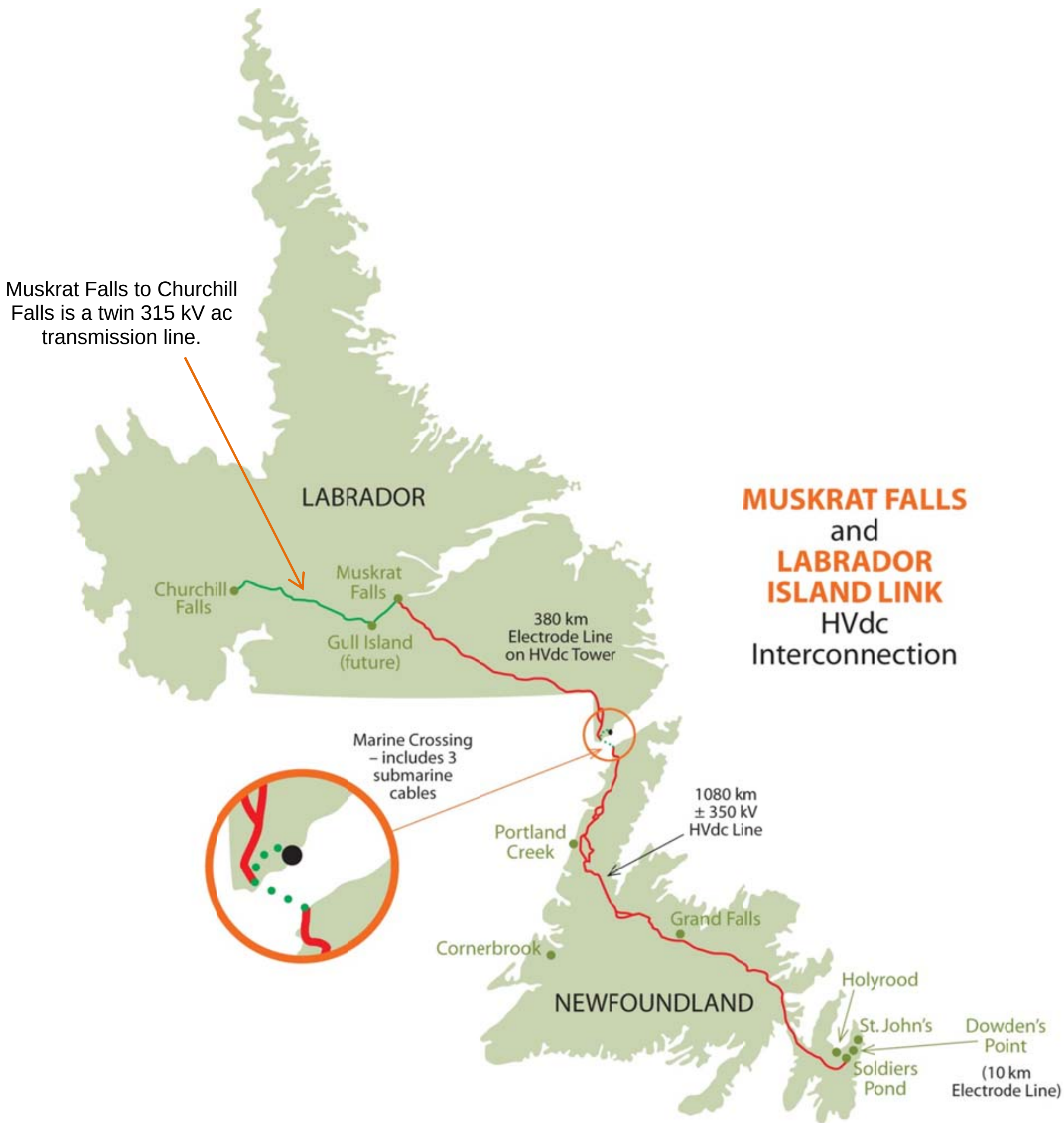


Figure 3: Interconnected Island Details

This section of the report describes the Load Forecast, ac integration studies undertaken by Nalcor, HVdc converter station and associated equipment, transmission system elements, the Strait of Belle Isle marine crossing, Muskrat Falls generating station, and other thermal and small generation sources added for this option. Detailed examination of the hydrology, reliability studies, or thermal supply options have been previously carried out and deemed not required as part of MHI's Decision Gate 3 review.

2.1 Interconnected Island Load Forecast

The purpose of this section is to analyze the 2012 Interconnected Island option to determine whether it was conducted with the due diligence, skill and care expected from an operation of this magnitude. Based on a number of documents provided by Nalcor to MHI, this section outlines the differences between the Load Forecast for 2012 Interconnected Island option and that prepared in 2010, compares levels of forecast growth versus historical growth, and updates the forecast accuracy tables. The analysis focuses on the total electric energy peak requirements on the Island of Newfoundland. The data reviewed focuses on the 20-year forecast period (2012-2031). The extrapolated forecast (from 2031-2067) is also reviewed for total Island energy requirements and interconnected Island system peaks.

2.1.1 Comparison of the 2012 Interconnected Island Option Load Forecast and the 2010 Load Forecast

This analysis compares the forecasts prepared in 2010 and 2012 where the 2012 Interconnected Island Load Forecast is being used as the basis for Decision Gate 3. Generally, the 2012 energy and peak forecasts are higher over the 20-year forecast period. The 2012 energy and peak forecasts converge towards 2010 forecast levels over the extrapolation period and cross over around 2057 (see Figure 4 and Figure 5).

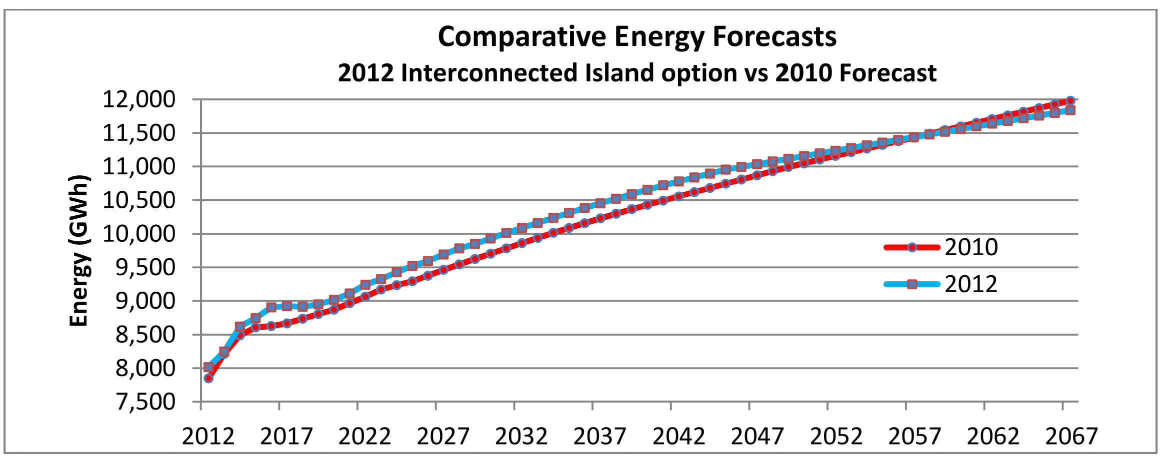


Figure 4: Comparative Energy Forecasts - the 2012 Interconnected Island option versus 2010 Load Forecast

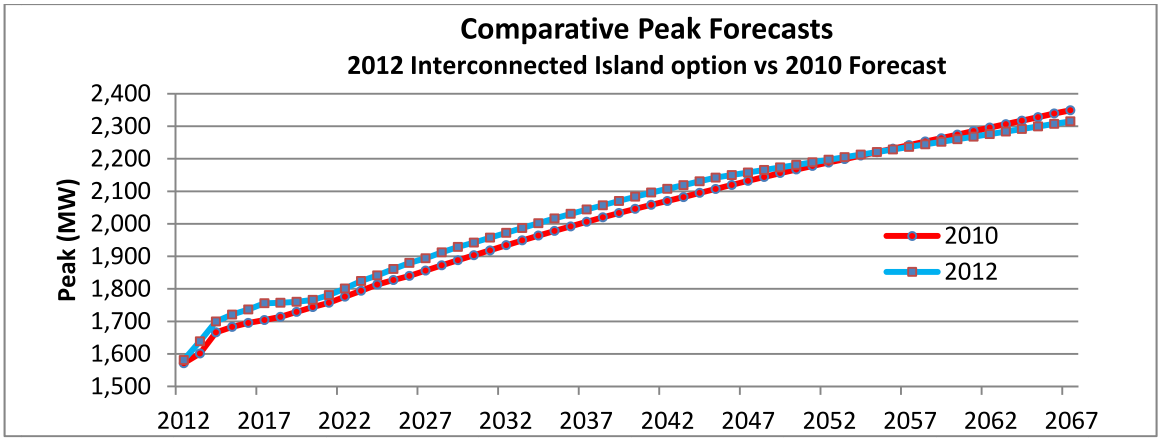


Figure 5: Comparative Peak Forecasts - the 2012 Interconnected Island option versus 2010 Load Forecast

Since the econometric sector forecasts prepared in 2010 covered the period of 2010 to 2029, this comparative analysis has a forecast start year of 2012, a forecast mid-point year of 2020, and a forecast long-term year of 2029. The results are included in Table 1.

Table 1: Comparison of the 2012 Interconnected Island option and the 2010 Forecast - Net Difference

	Energy (GWh)					Peak (MW)
Year	Domestic	General Service	Industrial	Other	Energy	
2012	177	-4	-53	44	164	10
2020	160	-67	37	14	144	22
2029	326	-156	37	14	222	41

In the year 2012, the 2012 Interconnected Island option predicts that total Island energy and peak requirements will be greater than the 2010 Load Forecast by 164 GWh and 10 MW, respectively. This increase is the result of a higher actual domestic load growth experienced in 2010 and 2011, caused by a significant number of new domestic customers and an increase in domestic weather-adjusted average use.

By 2029, the 2012 Interconnected Island option predicts that total Island energy requirements will be greater than the 2010 Load Forecast by 222 GWh. This increase is due to the higher domestic sector forecast, by 326 GWh, which is the result of a higher customer forecast and a higher average-use forecast.

Table 2 lists the differences between the 2012 Interconnected Island option and 2010 Load Forecast for the key economic assumptions and domestic consumption variables for the 2029 forecast long-term year. The higher domestic forecast for the 2012 Interconnected Island option (by 326 GWh) was due to a lower marginal price of electricity forecast (-1.17 cents), which will encourage electricity consumption such as electric space-heating, and the revised key economic assumptions as prepared by the Newfoundland Department of Finance, which raised forecasts for personal disposable income (by $1,501) and population (by 6,500). By 2029, the domestic average-use forecast was increased by 984 kWh in the 2012 Interconnected Island option, primarily due to a lower marginal price of electricity forecast, a higher saturation of electric space-heating forecast (2.0%), and a higher Personal Disposable Income (PDI) per customer forecast. By 2029, the domestic forecast predicted a greater number of total customers (3,496) and electric space-heating customers (7,437), primarily due to a higher actual customer growth in 2010 and 2011 than previously forecast.

Table 2: Comparison of the 2012 Interconnected Island option and 2010 Load Forecast in 2029 - Net Difference

Forecast	Avg Use	Electric Space Heat Cust.	Total Cust.	Electric Space Heat%	Marginal Price	PDI ($)	Population	CBI (000s)
2012 Interconnected Island option	17,015	178,824	254,627	70.2%	8.72	$15,196	513,200	$21,857
2010 Load Forecast	16,032	171,387	251,131	68.2%	9.89	$13,695	506,700	$22,797
Difference	984	7,437	3,496	2.0%	-1.17	$1,501	6,500	($940)

MHI considers the significant increase in the domestic forecast as an improvement over the 2010 Load Forecast because the 2012 Interconnected Island option is based on the higher customer growth and higher weather-adjusted average-use growth experienced over the last two years. The 2012 Interconnected Island option is also based on higher personal disposable income and population forecasts, which MHI considers more reasonable.

The higher domestic forecast was offset by a general service forecast that was 156 GWh lower, caused by a lower commercial business investment forecast, provided by the Department of Finance. The decrease in Commercial Business Investment (CBI) is questionable, considering that most other key economic assumptions were increased. Usually, an increase in the number of domestic customers and their relative prosperity will lead to an increase in general service investment and general service electricity consumption. ***Consequently, MHI considers the general service forecast prepared in 2010 as more reasonable and representative of an economy with moderate, consistent growth.***

The industrial forecast was 37 GWh higher due the combination of a higher energy consumption forecast for Vale Newfoundland and Labrador Limited (Vale) and a lower energy consumption forecast for Corner Brook Pulp and Paper Limited (Corner Brook mill). The other sector forecast, which consists primarily of distribution and transmission losses, was increased by only 14 GWh. System losses will increase as a result of higher total electricity sales.

By 2029, the 2012 Interconnected Island option predicts that the total Island interconnected peak will be 41 MW more than the 2010 Load Forecast. This increase is the result of a higher electric space-heating customer forecast and a lower marginal price of electricity forecast. MHI considers the increase in the peak forecast as an improvement over the 2010 Load Forecast because the 2012 Interconnected Island option is based on a higher number of electric space-heating customers.

By 2020, the 2012 Interconnected Island option predicts that total Island energy and peak requirements will be greater than the 2010 Load Forecast by 144 GWh and 22 MW, respectively. The domestic forecast was increased by 160 GWh, the general service forecast was decreased by 67 GWh, the industrial forecast was increased by 37 GWh, and the other sector forecast was increased by 14 GWh. Generally, the differences in the 2020 forecast mid-point year are caused by the same factors that explained the differences for the 2029 forecast long-term year.

2.1.2 Comparison of the 2012 Interconnected Island Option with Historical Growth

Table 3 compares the 2012 Interconnected Island option with historical growth. Total Island energy and peak requirements are expected to grow at a steady rate over the next 20 years. These forecasted growth levels are very similar to the historical growth experienced over the last 40 years. One apparent concern is that the total Island energy and peak forecasts over the extrapolation period (from 2031 to 2067) are too low. The extrapolated energy forecast (51 GWh) is only 44% of the load expected over the 20-year forecast growth rate (115 GWh). The extrapolated peak forecast (10 MW) is only 48% of the load expected over the 20-year forecast growth rate (21 MW). These reductions in future growth are significant and may be overly conservative. For example, the 10 MW of annual peak growth can be achieved by adding only 1,565 electric space-heating customers per year, which is much lower than the average addition of 3,551 electric-space heating customers per year over the last ten historical years (2001-2011). The extrapolated growth rates are lower due to lower growth of electric space-heating as the market becomes saturated and the assumption that no new industrial loads will locate on the Island over the extrapolation period.

Table 3: Annual Growth per Year – The 2012 Interconnected Island option and Historical Growth

Sector	Historical Growth Rate			Interconnected Island option	
				Forecast Growth Rate	Extrapolated Growth Rate
	1971-2011 (40-Year)	1991-2011 (20-Year)	2001-2011 (10-Year)	2011-2031 (20-Year)	2031-2067 (36-Year)
Domestic (GWh)	77	42	65	56	NA
General Service (GWh)	44	24	32	21	NA
Industrial (GWh)	-13	-58	-132	31	NA
Other (GWh)	8	3	13	7	NA
Island Energy (GWh)	117	12	-23	115	51
Island Peak (MW)	25	3	11	21	10

The 20-year forecast growth rate for the domestic sector (56 GWh) is expected to be less than the 10-year historical growth rate (65 GWh). This is because most electric space-heating conversions have already occurred, so fewer conversions are expected in the future. Conversely, the 20-year forecast growth rate is expected to be greater than the 20-year historical growth rate (42 GWh). This is because the economy is expected to outperform the historical period that included the economic downturn of the 1990s. ***MHI considers the 20-year forecast growth rate for the domestic sector to be reasonable.***

The 20-year forecast growth rate for the general service sector (21 GWh) is expected to be similar to the 20-year historical growth rate (24 GWh). However, the historical growth rate covered a period of economic downturn in the 1990s, and since another economic downturn is not anticipated in the future, the 2012 Interconnected Island option forecast for the general service sector seems to be conservative. MHI considers the 2010 Load Forecast for the general service sector to be more reasonable and representative of an economy with moderate, consistent growth. By 2029, the 2010 Load Forecast predicts that the general service load will increase by 156 GWh, or 8 GWh per year, over the 20-year forecast period. This would raise the 20-year forecast growth rate to 29 GWh per year, which would be similar to the 10-year historical general service growth rate (32 GWh).

The 20-year forecast growth rate for the industrial sector (31 GWh) is expected to grow due to the expansion of Vale and the assumption of continued operation of the Corner Brook mill.

The 20-year forecast growth rate for the other sector (7 GWh) is expected to be similar to the 40-year historical growth rate (8 GWh). The 20-year forecast growth rate for total Island energy (115 GWh) is expected to be similar to the 40-year historical growth rate (117 GWh). The 20-year forecast growth rate for total Island peak (21 MW) is expected to be 16% lower than the 40-year historical growth rate (25 MW).

2.1.3 Forecast Accuracy

A reasonable performance measure for forecast accuracy is a maximum forecast deviation of ±1% per year. A 10-year-old forecast, for example, should be within ±10% of the actual energy load observed. Table 4 measures forecast accuracy in terms of percentage of deviation from the actual load.

Table 4: Energy Forecast Accuracy Measured in Percentage of Deviation from the Actual Load

Years of History	1	2	3	4	5	6	7	8	9	10
Domestic (%)	-1.4	-2.2	-3.2	-3.9	-4.4	-4.8	-6.0	-7.4	-8.5	-10.2
General Service (%)	0.1	0.1	0.1	0.3	0.2	0.4	0.3	0.5	1.5	2.5
Industrial (%)	5.0	13.3	26.0	40.8	59.6	70.4	88.0	100.5	122.4	125.3
Other Loads (%)	-3.1	-4.3	-5.0	-6.7	-7.9	-8.7	-8.1	-7.6	-7.1	-9.2
Island Energy (%)	0.3	1.7	3.5	5.8	8.7	10.4	12.4	13.5	15.9	15.3

Past domestic forecasts have been reasonable, but have under-predicted future energy needs at a rate of 1% per year into the future. The domestic forecast under-predicted energy consumption in 63 of the 65 cases analyzed. This under-prediction probably results from conservative assumptions for key economic variables and not from the model specification. Past forecasts for the general service sector have produced remarkably good results.

In the past, the industrial sector forecast has not performed well. The assumption of continued operation of the pulp and paper mills at Stephenville and Grand Falls was overly optimistic, causing problems that have affected the industrial forecast accuracy. The total Island energy forecast is prepared by summing the four sector forecasts, and consequently, the industrial forecast has affected the results for total Island energy requirements. Table 5 shows that all of the total Island energy forecast deviation can be associated with the overly optimistic industrial forecast. In fact, the Island energy requirements would be under-forecast if the industrial forecast was accurate.

Table 5: Energy Forecast Accuracy Measured in GWh of Deviation from Actual Load

Years of History	1	2	3	4	5	6	7	8	9	10
Domestic (GWh)	-45	-72	-108	-130	-149	-163	-209	-260	-303	-366
General Service (GWh)	2	3	2	7	5	9	6	12	33	55
Industrial (GWh)	86	221	403	617	866	1,014	1,209	1,330	1,524	1,544
Other Loads (GWh)	-19	-26	-30	-40	-47	-52	-50	-47	-44	-58
Island Energy (GWh)	24	127	268	454	675	809	956	1,035	1,209	1,175

Table 6 measures forecast accuracy in terms of percentage of deviation from the actual peak load observed. The Newfoundland Peak demand regression equation accounts for 80% of the Interconnected Island demand and has performed extremely well. The Other peak forecast, which includes the peak demand associated with the Newfoundland and Labrador

Hydro (NLH) rural system, the NLH transmission system, and the industrial customers served by NLH, has not performed well. The Other peak forecast has been over-predicted as a result of a high industrial peak demand forecast. Since the Interconnected Island system peak demand forecast is prepared by summing the Newfoundland Power (NP) and the Other peak forecasts, the Interconnected Island peak forecast has also been affected by the high industrial peak demand forecast.

Table 6: Peak Forecast Accuracy Measured in Percentage of Deviation from the Actual Load

Years of History	1	2	3	4	5	6	7	8	9	10
NP Peak (%)	2.1	0.8	1.2	0.6	0.8	1.3	1.1	0.6	-0.2	0.2
Other Peak (%)	-4.5	-1.9	3.5	11.6	19.5	24.3	30.0	36.1	40.8	57.8
Island Peak (%)	0.3	0.1	1.6	2.9	4.7	6.1	7.1	7.8	7.9	11.1

Table 7 shows that the entire Interconnected Island peak forecast deviation can be associated with the high other peak demand forecast (rural, transmission & industrial).

Table 7: Peak Forecast Accuracy Measured in MW of Deviation from Actual Load

Years of History	1	2	3	4	5	6	7	8	9	10
NP Peak (MW)	22	9	14	8	10	15	13	7	-2	3
Other Peak (MW)	-18	-8	9	37	63	78	96	113	125	166
Island Peak (MW)	4	0	24	44	73	93	109	120	122	169

2.1.4 Summary

Regression models for the domestic sector are well founded and produce reasonable results. The 2012 Interconnected Island option increased domestic load by 326 GWh by 2029. MHI considers the increase reasonable and an improvement over the 2010 Load Forecast because the latest forecast is based on more current information for the number of customers, the weather-adjusted average use, the marginal electricity price, and higher economic forecasts for personal disposable income and population.

Regression models for the general service sector are well founded and produce extremely good results. The 2012 Interconnected Island option decreased general service load by 156 GWh by 2029 due to lower levels of growth for commercial business investment. MHI considers the lower forecast for commercial business investment conservative, thus producing a conservative forecast for the general service sector.

The customer-specific methodology used to prepare the industrial forecast is reasonable. With the current industrial forecast, the 2012 Interconnected Island option forecast should perform well over the next 5 to 10 years. In the longer term, the potential for new industrial loads would increase the likelihood of under-predicting future industrial energy requirements. With potential reductions in industrial load, the 2012 Interconnected Island option forecast will over-predict energy requirements in the next five to ten years. In the longer term, the Corner Brook mill load could be replaced by new potential industrial loads. The 2012 industrial forecast does not include any potential increase for new industrial customers after the expansion to Vale is completed. The industrial forecast should contain some allocation for potential future industrial loads.

The total Island energy and peak requirements have been over-predicted as a result of pulp and paper closures that were not accounted for in the industrial forecast. Otherwise, the total Island energy and peak forecasts have performed extremely well. The primary concern is that the total Island energy and peak forecasts over the extrapolation period are too low. The extrapolated energy forecast is only 44% of the load expected over the next 20 years. The extrapolated peak forecast is only 48% of the load expected over the next 20 years. These reductions in future growth are significant and may be overly conservative. MHI notes that the Interconnected Island option is more resilient to large increases in load. This impact is further discussed in the CPW sensitivity analysis section 4.7.

MHI finds that the Interconnected Island Load Forecast is well founded and appropriate as an input into the Decision Gate 3 process.

Figure 6: Newfoundland and Labrador Generation and Transmission System Map

2.2 AC Integration Studies

As part of the Decision Gate 3 analysis, MHI has evaluated the ac integration studies considering the latest project definition with generation at the Muskrat Falls Generating Station using a point-to-point HVdc transmission system (Labrador-Island HVdc Link) with the inverter station at Soldiers Pond. With the documents Nalcor provided to MHI as part of the Decision Gate 3 review, the ac integration study review has now been completed.

A total of six studies were provided by Nalcor to MHI, and comprise the ac integration analysis for Muskrat Falls Generating Station and Labrador Island HVdc Transmission System. These studies are reviewed in detail in Sections 2.2.1 through to 2.2.6, and in Section 2.2.8.

2.2.1 Construction Power Study

The construction power study examines options to supply a maximum load of 12 MW, which is expected to be reached in 2015, at the Muskrat Falls construction site in Labrador. The SNC Lavalin study recommended the following:

- Replace the two existing 25/33/42 MVA, 230/138 kV transformers at Churchill Falls with a larger 125 MVA bank that has an on-load tap changer with a tap range of +5% to -15%. The two existing transformers and the gas turbine at Happy Valley are expected to remain connected for back-up supply during the construction period to cover for failure of this new transformer.
- Install a temporary 6 km 25 kV transmission line to connect the construction power site to the Muskrat Falls tap station. An additional 10 km 25 kV transmission line will be constructed to connect the construction site to the camp site.
- Use direct line to line motor starters for the large motors connected at the construction power site.
- Install six 3.6 MVAr capacitor banks at the Muskrat Falls tap station on the 25 kV bus. Each capacitor bank is equipped with a 0.1 mH series reactor.
- Install a new 30/40/50 MVA 138/25 kV transformer at the Muskrat Falls tap station. The size and impedance need to be checked to ensure motors at the construction power site will successfully start. The contractor is expected to supply a 25/0.6 kV transformer. The impedance and size of this transformer also need to be checked to ensure that the motors will successfully start.

The construction power supply study meets good utility practice. The above plan is robust and can supply up to 15 MW of peak load while meeting voltage criteria.

The original estimate of 6 MW used in 2010 was an old estimate calculated by Hatch Consultants in the early 1980s that did not include detailed engineering. Nalcor has good confidence in the 12 MW estimate as it was calculated by SNC Lavalin using recent information and detailed engineering calculations.

A 600 hp motor was considered to be the largest size that might be used at the construction site. Starting this motor resulted in a 4% voltage drop at the point of common coupling and 20% at the 600 V motor bus. This was considered acceptable in the report. Depending on the actual construction power motor load, such as larger motors, larger starting current, and frequent starts, there could be issues with voltage flicker or with motors tripping in the construction camp depending on their protection settings. Nalcor has indicated that the load estimate is mature including the number of large motors. The two 600 hp motors will at most start one or two times per day. The contractor will be made aware of the network limitations.

Only one 138/25 kV supply transformer is being proposed. In discussions with Nalcor, MHI indicated that it would be good utility practice to install two banks to ensure a reliable supply for the duration of the construction period. These two supply transformers should have staggered in-service dates to eliminate common mode failures during transport and installation. Nalcor indicated that a spare 138/25 kV transformer already exists at Happy Valley. This 28 MVA transformer has been a cold standby transformer at Happy Valley for the past twenty-five years. This transformer will be fully tested prior to the in-service date of the construction power substation and will be moved to Muskrat Falls if a failure occurs. In addition, two 2 MW diesel generators will be on-site for emergency power. ***Nalcor's construction power contingency plan is reasonable.***

The recommended capacitor bank size of 3.6 MVAr results in a 2.7% voltage change assuming maximum fault level. This voltage change is at the borderline of flicker visibility. If this were a permanent installation, normal utility practice would be to consider sizing the banks to avoid voltage flicker based on the minimum fault level. Adding a second transformer bank to improve supply reliability would help to reduce voltage flicker and lower the net impedance, which would improve the motor starting performance. Nalcor indicated preference to not move the bank unless absolutely necessary to minimize risk and cost. The long term plan is to use this transformer at Happy Valley. Customer loads connected to the 138 kV network are not sensitive to voltage flicker. ***Nalcor's capacitor bank plan is reasonable.***

If there are sources of harmonics on the 138 kV network, then the series impedance of the 138/25 kV transformer and capacitor banks should be sized to avoid a characteristic harmonic; especially the fifth harmonic. Transformer saturation due to elevated voltage levels is one common source of fifth harmonic. Nalcor indicated no known sources of harmonics and system voltages were typically less than 1.0 pu, which generally means the transformers are not saturated and not supplying fifth harmonic current. Therefore, series harmonic resonance issues are not expected.

2.2.2 Stability Studies

The stability studies in the SNC Lavalin report examined the impact of the 900 MW Labrador-Island Link HVdc system and the 500 MW Maritime Link on Newfoundland primarily, as well as the ac network between Churchill Falls and Muskrat Falls in Labrador. The Labrador-Island Link HVdc system is expected to be in service on July 1, 2017 and first power is expected at Muskrat Falls in July 2017 with each subsequent unit coming online every two months. For the purposes of the MHI Decision Gate 3 review, the Maritime Link is considered to be out of scope for this review.

The four-unit (4x206 MW, 0.9 pf) Muskrat Falls generation case was examined as Nalcor indicated this is the base plan that has been selected. Also, part of the 300 MW recall option from Churchill Falls is available to be used to supply Newfoundland load with a 90% capacity factor. As a result, the availability of generation at the rectifier of the Labrador-Island Link HVdc system is very high. Availability is only limited by the availability of the Labrador Island Link HVdc system.

Contingencies examined included permanent dc pole faults, temporary bipole faults and three-phase normal clearing ac transmission faults. The selection of faults generally conforms to NERC category B or n-1 disturbances.

For the Labrador-Island Link HVdc, it was recommended in the SNC Lavalin stability study to:

- Install line-commutated HVdc converters for the Labrador-Island Link HVdc system. The link should be designed with a 10-minute, 200% overload rating, and 150% continuous overload rating while in monopolar operation.
- Install three 150 MVAr high-inertia synchronous condensers. The study assumed that one of the three synchronous condensers are out for maintenance.
- Evaluate settings of under-frequency relays to ensure proper coordination, such as avoiding operation for high rate of change of frequency if not required.

The largest contingency of the existing Nalcor system is currently the loss of the entire Holyrood plant for a nearby three-phase fault. After 2021, it is proposed to retire Holyrood and only operate the plant as a synchronous condenser. Nalcor indicated in meetings that the Holyrood generators were tripping off due to the plant auxiliaries not having sufficient low voltage ride-through capability. With retirement of the boilers, Nalcor does not expect there to be any remaining plant auxiliaries that would impact the synchronous condensers and affect the operation of the HVdc link.

Nalcor provided information on generator under-frequency protection settings. The Holyrood units have a setting of 58.8 Hz and 45 seconds. For the cases simulated, the worst case was roughly 58.8 Hz for a temporary bipole block. There are no concerns with loss of additional generation with the Labrador-Island Link HVdc system as the minimum frequency is planned to remain above the first block of load shed trip point of 58.8 Hz with 0.1 second pickup time.

There could be advantages to specifying some short-term overload capability while in bipolar operation to cater for large generator outages on the Newfoundland network. Nalcor will be including this question in the converter request for proposal. Nalcor agrees that having access to additional spinning reserves from Labrador will have operational advantages. There are concerns with having the continuous nameplate rating of the link larger than 900 MW. Also, the proposed reactive power support may be insufficient unless the new 150 MVAr cold standby spare is made a hot standby.

Nalcor indicated they had upgraded some of their generating units with high-speed exciters that had power system stabilizers, and had plans to modernize the remaining units. However, all of the power system stabilizers on Newfoundland are turned off. The stability studies did not indicate any issues with poor damping of power oscillations and Nalcor indicated that no issues have been reported during real time operations. MHI recommends that a small signal stability study[2] be undertaken in the detailed design stage of the project to confirm that power system stabilizers are not needed or to determine the preferred settings for the power system stabilizers.

The stability study meets good utility practice.

Permanent Bipole Block

From an n-1 perspective, the Interconnected and Isolated Island options are different in terms of network impact following loss of the largest generator. No load-shedding is planned to occur following the loss of the largest generator in the Interconnected Island option. The Isolated Island option is a continuation of the status quo, which permits under-frequency load shed to occur. The Isolated Island option would require significant investment to match the

[2] The recommended study would be a small signal stability study. Such a study is able to determine which generators participate in power system oscillations and the best settings for damping low frequency (0.1 to 2 Hz) power system oscillations.

improved reliability of the Interconnected Island option. Additional inertia would be required as well as additional generation to supply spinning reserves.

From an n-2 perspective, the permanent bipole block results in a potential loss of up to 900 MW at the rectifier for the Interconnected Island option. A permanent bipole fault is a low probability event; however, it is a credible event. The Isolated Island option would have an n-2 generation loss between 340 MW (loss of two generators) and 520 MW (loss of the Holyrood plant). This is a major difference between the Isolated Island option and Interconnected Island options. There are no planning criteria in Newfoundland that requires prevention of instability for a permanent bipole fault. However, there is a requirement to minimize under-frequency load-shedding. It may be possible to separate Newfoundland into separate zones following a permanent bipole block to minimize the amount of load shed as well as to improve system restoration times. Nalcor indicated during the meeting that it was already investigating this as a potential mitigating measure.

The stability studies in the SNC Lavalin report examined the impact of the 900 MW Labrador-Island Link HVdc system on Newfoundland as well as the ac network between Churchill Falls and Muskrat Falls in Labrador. ***This study was performed according to good utility practice.***

2.2.3 Load Flow and Short-Circuit Studies

Short-circuit and load flow studies performed by SNC Lavalin were reviewed by MHI as part of the Decision Gate 3 review. ***Short circuit and load flow studies were performed according to good utility practice. No equipment concerns were noted in this study.***

From the SNC Lavalin study it was initially unclear whether the 138 kV and 69 kV networks are radial or networked. These networks were ignored in the study and assumed radial. Higher loading on the 230 kV network could impact underlying low voltage networks. In discussions with Nalcor, they indicated that there are three 138 kV transmission lines that are networked as follows:

- Holyrood to Western Avalon
- Sunnyside to Stony Brook
- Stony Brook to Deer Lake

Nalcor indicated that it does not currently have a spinning reserve criterion. For loss of the largest generator today, it relies on under-frequency load-shedding to prevent a widespread blackout. Under-frequency load shed is being used instead of spinning reserves. The same practice was applied to the analysis of load flow case of long-term future planning year. This case is set up without generation reserves, which means any generator outage results in load-shedding. Nalcor provided a guideline for Unit Maximum Loading that indicates the secure limit for the maximum plant as a function of system load. This guideline ensures that sufficient load is able to be dropped to prevent the frequency from falling below 58 Hz. Nalcor has made some investigations into adding spinning reserve to match the size of the largest unit loss and doubling the inertia of all existing units. This approach does not eliminate under-frequency load shed. The Interconnected Island option, with the addition of high-inertia synchronous condensers is able to improve this situation and avoid load-shedding for a single contingency.

From the SNC Lavalin report, and with clarifications by Nalcor, the equivalent short circuit ration (ESCR) at the Soldiers Pond was calculated with the assumption of synchronous condensers at Holyrood, and with none at Soldiers Pond.

2.2.4 HVdc System Modes of Operation and Control Strategies Study

The HVdc System Modes of Operation and Control Strategies Study conformed to good utility practice and properly identified the different configuration modes and operational modes.

Some items of a technical nature were raised during the meetings with Nalcor and it was determined that they were not material to the CPW analysis. For example, one item raised was that a pole block while in the loop power flow control mode could result in over-voltages requiring filter tripping. This contingency was not tested in the stability or power flow studies. MHI noted to Nalcor that it is recommended to simulate tripping of either pole and confirm the over-voltage impacts. Another item raised was whether there is a need to utilize overload capability while in this mode to increase the speed of ice melting, and whether there is concern if the import pole trips. The loop power flow control mode should automatically switch off if a pole trip occurs. Nalcor indicated that it will clarify this item during HVdc design studies. There should be no impact on cost or the CPW analysis. In the worst case, there would be a need for an addition of a filter overvoltage relay.

2.2.5 Harmonic Impedance Studies

The harmonic impedance of the ac network was calculated at Muskrat falls and at Soldiers Pond. This study was conducted according to good utility practice.

MHI recommends that the harmonic impedance study consider operation with three 150 MVAr synchronous condensers in operation as this may occur for high loads or outages of transmission lines near Soldiers Pond. Nalcor noted this recommendation and will recalculate the harmonic sectors for the Labrador-Island Link Request for Proposal.

A list of shunt reactors and capacitors near the converter station was not included in the harmonic impedance study to ensure appropriate sensitivity cases were completed. In discussions with Nalcor, they provided a list of capacitors and reactors up to four buses away and confirmed that sufficient variations were included in the harmonic study.

2.2.6 Reactive Power Studies

This SNC Lavalin report for Nalcor determined the steady-state reactive power capabilities of the ac network over the feasible operating voltage range of the HVdc converters. ***The report is written following on good utility practice.***

The inverter could be thought of as a generator interconnection and the inverter could be required to supply reactive power over the range 0.95 leading to 0.95 lagging at the point of interconnection over the complete operating voltage range between 0.95 and 1.05 per unit. Alternatively the link could be designed to operate at unity power factor or be self-sufficient in reactive power. Nalcor does not have a published grid code that defines the reactive power or voltage control requirements for new generator interconnections. Requirements are determined on a case-by-case basis depending on the size and location of the generator. For Muskrat Falls, no reactive power exchange was assumed available from Churchill Falls. With one unit out at Muskrat Falls, assuming filters were in-service supplying 25% of the reactive power of the rectifier, the remaining Muskrat Falls units were required to hold the 315 kV voltage at 1.02 pu. This required the units to be rated at 0.9 pf. At the inverter, assuming the filters provide 25% reactive support, the synchronous condensers are required to hold the voltage to 1.02 pu at maximum loading. ***This methodology is reasonable and consistent with the voltage and reactive power regulations used by the industry.***

2.2.7 Preliminary Transmission System Analysis – Muskrat Falls to Churchill Falls Transmission Voltage

The Preliminary Transmission System Analysis report examines the voltage options to interconnect the Muskrat Falls generating station to Churchill Falls. Four single-conductor 230 kV lines, three two-conductor 230-kV lines, and two two-conductor 315 kV or 345 kV lines were compared. Two 345 kV lines with 45 MVAr shunt reactors located at both sending and receiving ends were recommended. The 345 kV lines could also be built to 315 kV. **This report is in accordance with good utility practice and makes sound recommendations.**

According to Nalcor, the voltage level was selected at 315 kV for economic reasons. In addition, the 45 MVAr shunt reactors were removed in favour of using on-load tap changer capability and the reactive power capability of the Churchill Falls and Muskrat Falls generating stations.

MHI noted one concern; Nalcor intends to extend its normal practice on 230 kV lines in Newfoundland and implement single-pole trip and reclose on the new 315 kV transmission lines between Churchill Falls and Muskrat Falls. High voltage long lines greater than 300 kV quite often employ four-pole reactors to help improve the probability of extinguishing the secondary arc current, thus ensuring a successful reclose[3]. Without these reactors, a longer pole open dead time may be required or single-pole trip and reclose may need to be disabled. For the transfer levels studied, single-pole trip and reclose was not demonstrated as necessary to maintain stability. Nalcor noted this concern and will further investigate the need of single-pole trip and reclose and the feasibility of single-pole trip and reclose with and without four-pole reactors. There is some minimal risk that one or two four-pole reactors will need to be added with additional cost to each of the 315 kV lines, which will increase the cost by approximately $2 million per reactor installed for a maximum exposure of $8 million.

2.2.8 Labrador-Island HVdc Link and Island Interconnected System Reliability

The Labrador-Island HVdc Link and Island Interconnected System Reliability study compares the reliability of the Island Link HVdc to the existing system reliability. The impact of the Maritime link is quantified and the design criterion of the HVdc transmission line is discussed. ***This study meets good utility practice.***

With the Island link transmission line designed for a 1:50 return period, assuming a 14 day restoration time to fix transmission outages, results in a maximum 1% annual unserved energy. The report characterized the 1:50 return period being for ice-loading only but Nalcor clarified that this was for both wind and ice-loading.

A more accurate calculation method would have required the use of a probabilistic assessment tool. However, the purpose of the Nalcor study was to provide a simple quantitative comparison between the status quo and potential futures in terms of the impacts of major outages due to ice storms. The report fulfills this purpose.

2.2.9 Summary

The AC Integration Studies that were reviewed follow good utility practice and are adequate to define the minimum transmission facilities needed to:

- Supply the expected maximum construction power load of 12 MW at Muskrat Falls,

[3] IEEE Committee Report "Single Phase Tripping and Auto Reclosing of transmission Lines", pp. 185, Jan. 1992. In table III of the IEEE Committee report, they note for 345 kV lines greater than 140 miles, additional measures must be undertaken to reduce the secondary arc current.

- Interconnect four 206 MW Generating units at Muskrat Falls, and
- Deliver the output from approximately 900 MW of generation in Labrador to Newfoundland load.

There is a remote possibility that up to four 45 MVAr 315 kV four-pole shunt reactors may be needed to permit successful single pole tripping and reclosing on the new 315 kV lines between Churchill Falls and Muskrat Falls. The maximum cost impact is $8 million. However, it is possible to avoid this cost by potentially disabling single pole trip and reclose.

MHI recommends:

Harmonic impedance sector calculations include cases where all three synchronous condensers are in operation for both system intact conditions and 230 kV ac transmission line prior outages. The study can be performed in the detailed design stage to provide the HVdc suppliers adequate information to design the ac filters.

Further work should be conducted to design a special protection scheme that will balance available generation with load following a permanent bipole outage on the Labrador Island HVdc Link. The 230 kV transmission system on the Island can be configured to trip specific transmission lines with the use of an appropriate under frequency or rate of change of frequency relay, or direct tripping signal from the HVdc converter station at Soldiers Pond to balance load with generation. This study is not critical to Decision Gate 3 and can be completed prior to the in-service date of the Labrador-Island Link.

A power system stabilizer study should be conducted in the detailed design stage to determine appropriate settings for the Muskrat Falls Generating Station as well as for generators and synchronous condensers in Newfoundland. The study is not required for Decision Gate 3 but good utility practice dictates that it be performed as part of the detailed design.

The result of the six studies conducted by SNC Lavalin for ac integration demonstrates that Nalcor is in compliance with good utility practice. There is an opportunity during detailed design to optimize final configurations that may enhance the system reliability.

2.3 HVdc Converter Stations

The assessment of the technical work done by Nalcor on the HVdc converter stations, electrode lines, and associated switchyard equipment was undertaken by MHI as part of its Decision Gate 3 review of the two options. This review was carried out by HVdc experts on staff at MHI through meetings with Nalcor and reviews of a number of confidential documents provided by Nalcor.

2.3.1 HVdc Configurations

The system single line diagrams were reviewed for the HVdc converter stations (dc yard) at both terminals with electrode sites, the new 315 kV ac switching station at Muskrat Falls, the ac system extension at Churchill Fall 735 kV / 315 kV switching station, and the new 230 kV ac station at Soldiers Pond. The dc and ac yard layouts as shown in the single line diagrams follow good utility practice and the identified system upgrades are well supported by the study reports described in AC Integration Study Review Sections 2.2.2, 2.2.4, and 2.2.6. The planned transmission outlet facilities at Muskrat Fall and Soldiers Pond are adequate for the proposed HVdc Link rating. Three high-inertia synchronous condensers are planned to strengthen the system and assist in voltage and frequency control.

2.3.2 Reliability and Availability Assessment

The Reliability & Availability Assessment report presents the results of the reliability and availability analysis carried out to determine the expected reliability performance of the proposed Labrador-Island Link HVdc system. The Reliability and Availability performance indices for key system components including the converter stations, the HVdc transmission line from Muskrat Falls to Soldiers Pond, the submarine cables, the electrode lines and the composite reliability performance of the complete Labrador-Island Link HVdc system were derived and considered to be in the reliability performance range of the HVdc schemes in-operation today. The recommendations on provision of spare equipment such as converter transformers and smoothing reactors follow good utility practice.

The Nalcor study determined that the repair time of the HVdc transmission line failure has significant impact on the availability of the island HVdc link. Line design enhancement such as anti-cascading towers and a good emergency response plan are recommended for further evaluation as part of the detailed design stage post Decision Gate 3. Special care shall also be paid to the electrode line reliability, such as insulation coordination and arc extinguishing capability, due to its unique overload operation mode under pole outages and extreme long distance.

The electrode line and electrode section is dealt with in a limited fashion and requires more attention as this element is critical for the overload capability during mono-polar operation. Because of the long-distance of the electrode line on the Labrador side and the fact that during normal operation there is virtually no voltage or current (just the bipolar unbalance current), detecting the soundness of the electrode line is very difficult. The exact design would be part of the detailed engineering provided by the supplier. Investigation into fault detection and locating systems such as Pulse Echo systems for the electrode lines is suggested by MHI. Addition of this item would not materially impact the CPW of the overall project.

2.3.3 HVdc Master Schedule

The HVdc system master scheduling documents provided by Nalcor to MHI outline the schedules for procurement, installation, and commissioning of the HVdc converter stations and related components. The project schedules and execution times including engineering, procurement, and constructions are comparable to similar HVdc projects.

2.3.4 HVdc Cost Estimates

Master cost estimates provided by Nalcor to MHI for the HVdc converter stations, ac switchyards, synchronous condensers, and electrode sites were examined as part of the Decision Gate 3 review.

The capital cost estimate includes the system upgrades at the HVdc converter stations (both ac and dc yards) and the island system enhancement as well as replacement of high voltage breakers. Two shoreline electrodes and associated electrode lines are included in this estimate. The first electrode line from the Muskrat Falls converter station has a significant length of about 400 km and most electrode line will be mounted on the same HVdc overhead tower. The second electrode line will emanate from Soldiers Pond approximately 10 km to the electrode site near Dowden's Point in Conception Bay. The estimates on synchronous condensers are somewhat low based on MHI's experience on other projects, but are within the bands of cost estimate variability. The costs for Nalcor's synchronous condensers have been estimated from suppliers' quotations.

The capability of maintaining full HVdc power rating while losing one ac filter branch element was verbally discussed with Nalcor as MHI noted that this information was not included in the Short Form Specification sent to the suppliers. Nalcor has confirmed that each filter bank will be made up of several branch filters and will have redundancy at the branch filter level such that if one branch fails, or is disconnected for maintenance, there will be no need to de-rate the power transfer.

Sufficient contingency has been allocated to this portion of the project to offset any unforeseen project risks.

MHI finds that the estimates are reasonable as inputs to the Decision Gate 3 process and CPW analysis.

System Study Reports

The scope of work in the Nalcor study reports included power flow and short circuit analysis, harmonic study, reactive power study, transient stability analysis, HVdc control strategy and HVdc modes of operations.

The Load Flow and Short Circuit Studies and the Reactive Power Studies provide by Nalcor to MHI have determined the short circuit levels (fault levels) at converter stations, power dispatches under various load flow scenarios, and reactive power requirements for the proposed Labrador-Island Link HVdc system. The proposed system upgrades at Muskrat Falls and Soldiers Pond are adequate for the HVdc operating modes considered and the overload requirement. The ESCR requirements are met at both converter terminals with the proposed system upgrades and the HVdc system is expected to provide acceptable performance based on industry experience. The harmonic impedance study provides preliminary information for the filter designs with no adverse low-frequency system resonance identified.

Detailed HVdc performance under various contingencies is evaluated in the stability study report provided by Nalcor. It is worthy to note that Nalcor has stated that one of the main system development criteria is to achieve the same or better reliability than today's system considering its unique island electrical system configuration. The study results demonstrated the acceptable HVdc system responses of the proposed HVdc link following various ac and dc contingencies. Two 150 MVAr high-inertia synchronous condensers plus one spare are required based on system stability requirements.

The HVdc configurations, operation modes, control hierarchy and strategies, and communication requirements were presented in the study report provided by Nalcor to MHI. The basic philosophy outlined in this report conforms to good industry practice. The report stated that the final implementation requirements were to be developed and presented as part of the Technical Specifications. During islanded operation (i.e. when the Labrador Island HVdc Link is forced out of service), the impact of frequency excursions on control strategy will need to be evaluated during recovery operations. However, no implications on the additional costs are expected.

Short Form Technical Specification

Lower Churchill Project Short Form Technical Specification dated October 13, 2011 provided by Nalcor was reviewed as part of the Decision Gate 3 review by MHI. This document was provided to three suppliers to obtain cost estimates for the HVdc converter stations: ABB, Siemens and Alstom Grid. The Specification forms the basis for the costs estimates received from the suppliers. The typical practice was to discard the lowest estimate and average the two highest for budget preparation. This philosophy was carried forward in all cost estimates prepared for Decision Gate 3 where applicable.

There is a possibility of additional costs, depending on what assumptions were made by the suppliers in the preparation of their estimates. Given that Nalcor has indicated that they have used the average of the two highest estimates of three submitted, which were both relatively equal, MHI believes that this approach is reasonable when estimating budgetary costs.

2.3.5 Summary

MHI through its review notes the following important points:

- The study determined that the repair time of the HVdc transmission line failure has significant impact on the availability of the Labrador-Island Link HVdc system. Line design enhancements such as anti-cascading towers as planned by Nalcor will improve reliability. Development of a good emergency response plan is recommended by MHI as part of the operational stage of the project post Decision Gate 3. Nalcor has committed to have this emergency response plan developed prior to in-service.
- Due to the long-distance of the electrode line on the Labrador side, and the fact that during normal operation there is virtually no voltage or current in the electrode line, monitoring of the soundness of the electrode line is very difficult. Investigation into fault detection and location systems such as Pulse Echo systems for the electrode lines is recommended during the detailed design phase post Decision Gate 3. Addition of these detection systems is expected to have a minimal cost impact on the CPW analysis.
- The cost estimates for the synchronous condensers appear low when compared to other projects in Canada; however Nalcor has secured these costs directly from manufacturers. The cost estimates are within the bands of cost estimate variability for an AACE Class 3 estimate range.

Overall the project as indicated by Nalcor in documents provided appears reasonable. MHI has made some recommendations as outlined above that may provide improvements to the project.

The system upgrades identified in the single line diagrams for HVdc converter stations, ac switchyards, and electrodes are well supported by the study reports provided to MHI by Nalcor and are reasonable as inputs to the Decision Gate 3 CPW analysis.

2.4 HVdc Transmission Line, Electrodes and Collector System

The purpose of this section is to conduct a high level review of the HVdc lines, the electrode sites, and the high voltage ac (HVac) collector transmission system Nalcor proposed at Decision Gate 3.

Cost estimates, construction schedules, and the design methodology undertaken by Nalcor in preparation for Decision Gate 3 were examined and an assessment made of the reasonableness as inputs to a CPW analysis.

2.4.1 Schedule

Nalcor's proposed schedule for the HVdc and HVac line designs, procurement, and construction were reviewed through a series of interviews with key Nalcor personnel. A high level schedule for the existing project scope was requested by MHI and provided by Nalcor for examination.

At this time, detailed design of the transmission line structures is under way, and testing of critical line structures scheduled later this year. Nalcor has planned for detailed design right through the entire construction phase in the schedule. This is a prudent industry practice to support construction on large transmission projects with changing terrain necessitating field-specific design solutions.

Procurement activities have been staged in the first quarter of 2012. MHI understands much work has been done to verify pricing and supply of the various transmission line materials pending official Decision Gate 3 project sanction. To date, a total of 21 material procurement management packages are being prepared to fulfill the transmission requirements. To maintain the project construction schedule as planned, the majority of material contracts for long lead-time items such as towers, insulators, and conductors should be awarded by the end of 2012 for a fall 2013 or early 2014 construction start.

The construction window for all high voltage transmission line construction activities for the project complex has been allocated approximately four years with clearing activities starting in the second quarter of 2013. MHI finds the schedule to be reasonable and achievable provided construction work and equipment access is possible during all four construction seasons.

2.4.2 Cost Estimate Evaluation

Nalcor provided MHI with a detailed report on the Decision Gate 3 transmission line cost elements broken down into the key components described as: Construction, Supply, Geotechnical Exploration, and Right of way clearing.

Nalcor described the methodology in preparing the estimate and MHI considers that it accurately reflects the costs forecasted for the design and construction of the transmission lines.

The Decision Gate 3 estimate is based upon the following contributory factors:

- Costing from suppliers for detailed material breakdowns and known bulk quantities such as number of towers, insulators, and hardware
- Transmission contractor budgetary feedback based upon the proposed schedule and construction methodology and timelines
- Engineering concepts that are virtually complete, and scope changes tracked and identified
- Labour unit costing assuming a negotiated master labour agreement, equipment and commodity rates are identified
- Productivity factors for labor, equipment, while factoring in seasonal impacts.

Comparing the Decision Gate 3 cost estimate evaluated on a cost-per-line-km basis with other similar projects under way in Canada, MHI finds the Muskrat Falls transmission line component costs are at a reasonable level and accuracy for this stage of the estimate. ***The costs for the transmission lines are within an AACE Class 3 estimate accuracy congruent to the requirements of Decision Gate 3.***

2.4.3 Risk Assessment

Nalcor has identified the key areas of project risk in its project management strategy. At the current stage of project progress, the majority of major engineering decisions affecting transmission line design and construction have been made and costs estimated for Decision Gate 3. Nalcor has displayed appropriate controls and signing authority managing scope changes with the Transmission Deviation Alerts and the Change Notice document MHI reviewed.

With the level of engineering complete to date and the tracking system in place, the probability of major scope changes to the design affecting cost and schedule is assessed as very low. At this stage minor route changes will not affect cost or schedule significantly.

Material costing has been calculated with estimated line quantities at current market values and as such is likely to only vary with the final tower optimization quantities. These variations should not be significant from the quantities currently estimated.

At this stage, the major risks to be addressed for the transmission line complex remain as contractor cost, labour availability and productivity. Nalcor has identified this as a major risk and has identified mitigation strategies to attract skilled labour back into the province through a master labour agreement, training, and other self-development programs.

2.4.4 Assessment of Line Routes

MHI has reviewed the line route corridor provided in documents by Nalcor in topographical mapping format. The corridors MHI reviewed are the 2 km wide general study corridor running from Muskrat Falls across the Strait of Belle Isle to the Soldiers Pond Converter Station, and the 60-metre-wide proposed transmission line alignment contained within it. Work acquiring property and easements for the alignment is currently underway. MHI's assessment will be limited to the route corridor as it has been defined to date.

HVdc Transmission Line Route

The route selected for the HVdc line is optimal considering the primary criteria required for an efficient bulk point-to-point transmission line. The line has been designed to minimize the distance between the source of generation at Muskrat Falls and the load centre at Soldier's Pond, minimizing angle locations where possible. The route navigates the more difficult areas of Labrador, by-passing the numerous large lakes, ponds, and swampy terrain with a minimal number of line angles. All water crossings appear achievable with minimal custom site designs typified as shown in Figure 7.

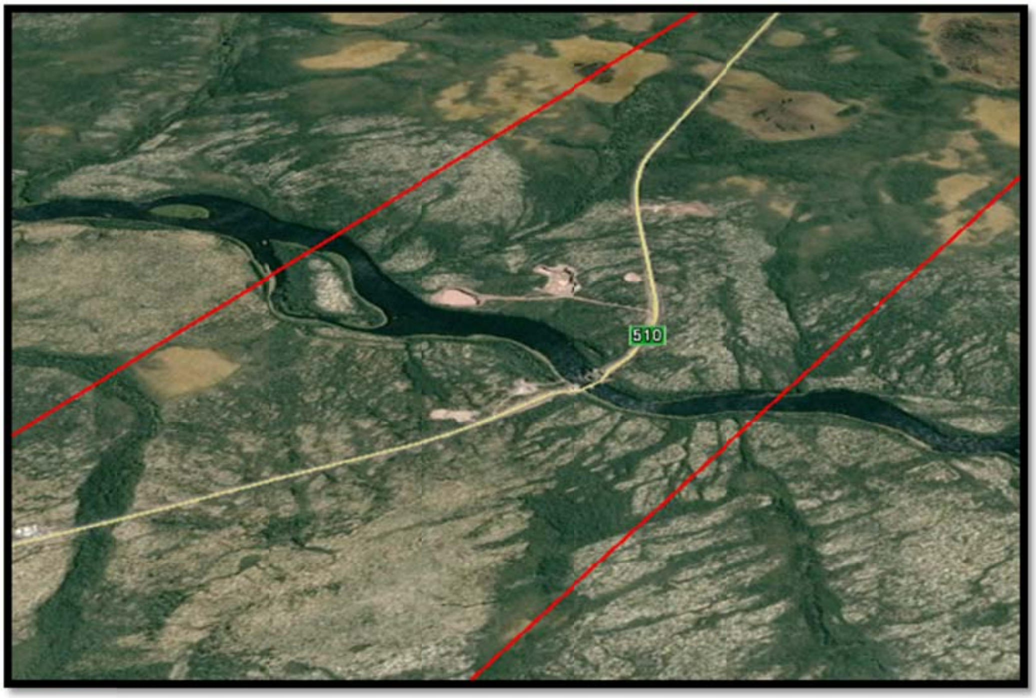


Figure 7: Typical river and highway crossings along the HVdc transmission line route. Crossing spans are achievable with the current transmission line design parameters.

The route proceeds as directly as possible through the Long Range Mountain Ridge before it turns east heading across the Newfoundland Island to the Soldiers Pond Converter Station.

Portions of the route are adjacent to major roads such as the Trans-Canada and Trans-Labrador highways. This will help facilitate access to clearing, construction of the line, maintenance, and with planning an emergency response scenario. A review of the corridor displayed numerous access trails which should enable reasonable access to the line in most seasons.

The entire transmission line corridor through Labrador and the Newfoundland Island is selected and under review for the environmental and licensing process. ***MHI finds the route was selected with due diligence and appears to be well suited for its purpose.***

AC Transmission Line Routing

The routing for the two 315 kV ac lines connecting Churchill Falls to Muskrat falls essentially follows the corridor of existing 138 kV transmission line TL 240. The corridor is well established and will be widened to an appropriate width to contain the additional two lines. MHI reviewed the transmission line corridor and does not foresee any difficulties with this planned corridor addition. Nalcor still needs to obtain appropriate approvals and easements.

Electrode Line Routing

Detailed routing for the small lengths of electrode line carried on single wood pole structures to the Labrador (25 km) and Newfoundland (15 km) Electrode sites were not reviewed in detail as these short lengths of electrode line will have minimal impact to overall project costs and the right of way.

2.4.5 Structure Families

MHI reviewed Nalcor's proposed structure families for the new transmission lines in meetings with Nalcor and reviewed formal and informal printed documentation from design files. Composition of final tower design and fabrication drawings is in progress and at an acceptable level of completion for this stage of the project.

Nalcor's design philosophy used to determine the structure families for the ac and dc transmission lines follows an industry-accepted practice of apportioning out structures into "families" classified by their function along the transmission line. Structure families proposed in the designs include tangent suspension structures, various degrees of angle structures, heavy angle, and termination structures used to sectionalize the line.

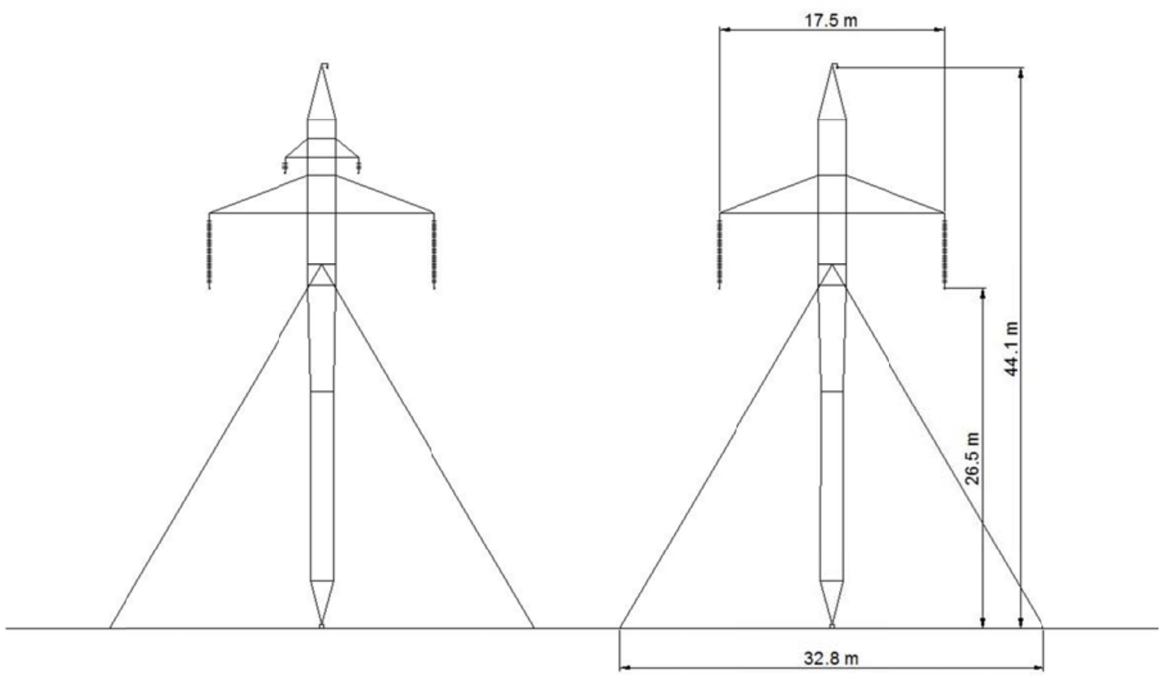
The tangent suspension towers Nalcor has selected for both ac and dc systems are composed of guyed lattice steel mast-type structures modifiable by height extensions to maximize tower utilization in the rolling terrain common along the entire corridor. These types of structures are the most economical choice given the variety of geophysical soil conditions, terrain to be crossed, and remoteness of the route selected. Use of these structure types is common throughout the industry, and there are many other examples of these towers successfully installed throughout North America.

Other structures proposed are lattice steel self-supporting towers typically positioned at angle locations and other sections in the line for termination purposes or boundaries between weather-loading zones. Critical to the performance and maintenance of self-supporting structures are suitable foundations for the terrain type. Nalcor has identified these tower locations for detailed geotechnical exploration which is acceptable methodology for structures of these types. Given the information provided by Nalcor, MHI finds that the selection made for structure families and types to be reasonable.

HVdc Transmission Line Structure Family

MHI reviewed Nalcor's design specification documents which outlined in detail the approach determining the tower design and geometry, span spacing, load capacity, and other detailed engineering criteria pertinent to the proposed HVdc transmission system. From extensive meteorological research, Nalcor determined that the transmission line would require 11 unique weather zones, with a number of subzones, to adequately model the ice-and-wind loading on line structures.

Engineering work is in progress to complete the detailed design for the HVdc line. Nalcor has defined 12 structure families, with a total of 25 structure types, required to economically construct the line. Wherever possible, an effort was made to use common structures in the various loading zones in an effort to minimize the number of unique, custom structures which mitigates design and construction cost.



HVdc Segment 1 (with electrode) HVdc Segment 2 (without electrode)

Figure 8: Typical HVdc Transmission Guyed Tangent Structures which comprise approximately 85% of the towers in the Labrador-Island HVdc transmission line

Nalcor's design controlled the structure loading from the various ice-and-wind loading combinations by reducing or increasing the ruling span in the 11 weather-zone regions. Generally, as the loading increased, the design ruling span and conductor tension was reduced. This is an acceptable approach to controlling the structure size and weight, and ultimately construction and logistics costs.

MHI has reviewed the various ice-and-wind loading cases and required structure families and has determined that Nalcor's design approach, given the severity and wide range of weather cases found along the transmission line route, is a reasonable and cost-effective methodology.

AC Transmission Line Structure Family

MHI reviewed Nalcor's design specification documents which outlined in detail the approach determining the tower design and geometry, span spacing, load capacity, and other detailed engineering criteria pertinent to the proposed HVac transmission system connecting the Churchill Falls Switching Station to the Muskrat Falls Switching Station.

Two 315 kV ac lines are proposed, and Nalcor has advised that only one structure family with five different tower types is required for the route. The structure family is composed of guyed steel lattice structures with self-supporting angle and termination structures. As this line is predominantly in one weather-loading zone, MHI concurs with Nalcor's decision in selecting this structure family design.

Electrode Line

For reasons of life-cycle economics and reliability, the electrode line on the Labrador portion of the HVdc line was recently moved from individual wood pole structures located along the right-of-way edge to a position on the HVdc line structures from Muskrat Falls to Forteau point. MHI finds it is a prudent decision to consolidate the HVdc pole and electrode conductors onto one supporting structure in the Labrador transmission line section. There are considerable cost savings in construction effort, material, and the long-term maintenance required of wood pole structures.

From Forteau Point to the Labrador Electrode site at L'Anse-au-Diable, and from the Soldiers Pond Converter Station to the Dowden Point electrode site, the electrode line is suspended on standard wood pole structures of similar size to a distribution pole system. MHI concurs with the design methodology that Nalcor selected for the electrode line system.

2.4.6 Assessment of Transmission Line Reliability

Nalcor made several prudent decisions regarding the detailed transmission line design to reduce the probability of an outage, and failure or progression of failures in line structures with the intent to increase the line's overall reliability. The following salient points highlight these decisions:

- The guyed structure configuration will naturally resist failure from cascading events and is more stable in the rugged terrain found along the route
- Provision of special anti-cascade towers every 10 to 20 structures to contain and isolate failures and prevent them from impacting large sections of line
- In sections of the transmission line with the most severe combined ice-and-wind loading, the spans have been shortened appropriately to reduce structure loading to manageable levels
- Selection of a single large conductor in place of a multi-bundled conductor arrangement. This prevents ice accumulations bridging across sub-conductors to form large shapes which would transfer high wind loads to structures. Nalcor has selected a large 3640 MCM 91-Strand all-aluminum conductor (AAC) family for the entire transmission line, and is currently investigating the use of high-strength aluminum alloy conductors of identical size for use in the extreme ice regions required to maintain reliability.
- Insulator suppliers were limited only to vendors with international reputations for quality, operational reliability, and who have established distribution networks that will allow them to comply with delivery schedules.
- Due to the effect the rolling terrain has on tower locations and optimization, the average tower strength utilization on tangent towers will be somewhat less than the designed capacity, with utilization possibly averaging between 75% and 85% of the ultimate strength. This has the effect of increasing tower resistance and stability during extreme weather events, thus increasing overall reliability.
- Selection of the final alignment within the route corridor attempted to minimize exposure to the extreme climatic-loading regions such as Long Range Mountain Ridge, and to avoid areas where the terrain acts to accelerate and funnel the wind.
- Tower window dimensions and spans are designed to comply with the most up-to-date theory predicting conductor motion in extreme wind and ice events. This will reduce or eliminate outages during these events, increasing the overall transmission line reliability.
- Tower prototype testing on the most common line structures to affirm capacity and behavior under loading is scheduled for late 2012.

MHI finds Nalcor has completed a thorough assessment of the various climatic regions impacting the ±350 kV HVdc line from Muskrat Falls to the Soldiers Pond transmission line route. In documents provided by Nalcor to MHI, the meteorological research determined that 11 zones along the route corridor with a number of subzones, each with a unique zone-specific climatic loading is required to reliably predict climatic loading to the transmission line (see Figure 9).

The climatic loadings for each line section were selected based on Nalcor's past research studies and statistical analysis of the climate data. Extreme values based upon historical data and observations on ice accumulation and wind speed were implemented in the line regions through the Long Range Mountains and other regions in Labrador. This follows the recommendations of CAN/CSA A.7.2 where designers are cautioned to investigate and design for areas with localized higher icing and/or wind forces. It is MHI's opinion Nalcor undertook appropriate due diligence selecting the weather loads for this transmission line.

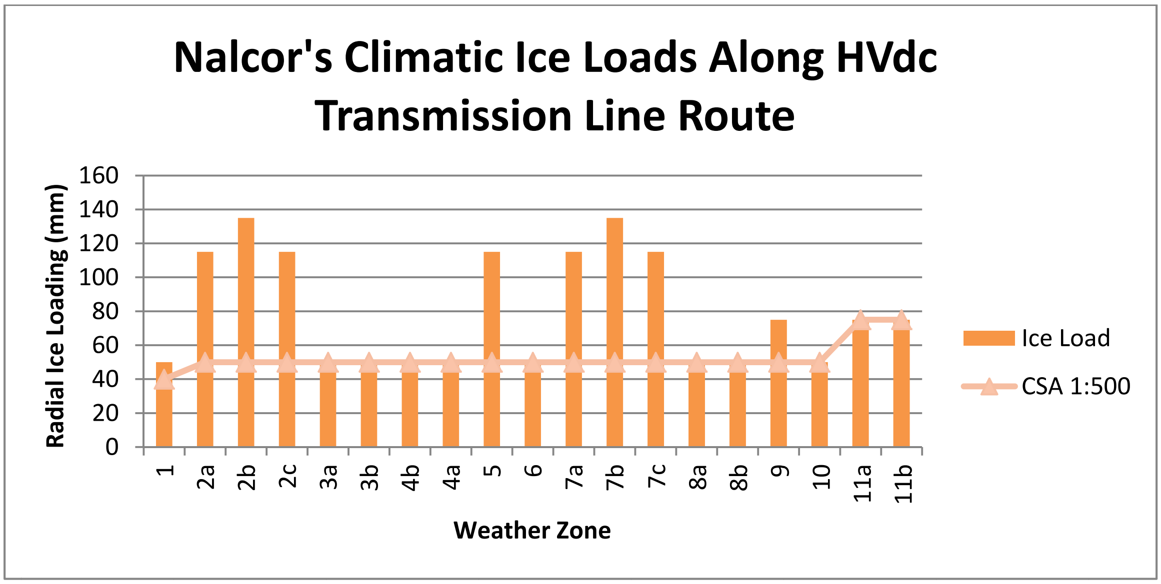


Figure 9: Climatic Ice Loads along the HVdc Transmission Line Route compared to the CSA Standard 1:500-year return period limit

Nalcor's research studies to define the climatic loadings along the transmission line route were based on 50 years of data, as outlined in the document "Muskrat Falls Project – Exhibit 97, Appendix A Revision 1". The climatic loadings for each line section are approximately equivalent to the climatic loadings calculated assuming Canadian Standards Association (CSA) 1:500 year-return period.

MHI notes that CAN/CSA C22.3 suggests a greater reliability of design to 1:150-year or 1:500-year return periods for lines of voltages greater than 230 kV which are deemed of critical importance to the electrical system. It is MHI's opinion the ±350 kVdc and 315 kV ac lines proposed for the Lower Churchill Project be classified in a critical importance category due to their operating voltage and role in Nalcor's long term strategic plan for its transmission system and be designed to a reliability return period greater than 1:50 years.

Nalcor, as part of the detailed design post Decision Gate 3, is aware that increased reliability is needed in the Long Range Mountains and other regions in Labrador subject to extreme wind and icing conditions and has taken actions to upgrade portions of the line.

Nalcor, from its own analysis of the climatic loading study and information acquired from experience in the region, has specified a transmission line design criteria that exceeds the ice loading requirements experienced in Newfoundland and Labrador over the past 50 years.

2.4.7 Emergency Response Plan

Emergency response plans for an HVdc outage scenario will be instituted once the line is placed into service and is not normally part of the Decision Gate 3 review process. Informal discussions with key Nalcor staff were held on the topic to determine what, if any formalized emergency restoration is planned. Emergency response times to restore the line to normal operating conditions are very difficult to predict due to the remoteness of the transmission line and levels of failure possible. Outage periods up to one month or greater in remote line sections are possible. The emergency response plan needs to consider the availably of alternate generation in addition to the potential duration and extent of an HVdc transmission line outage. Nalcor acknowledges that an emergency response plan is necessary and will undertake the development of one prior to in-service.

The items addressed for possible follow-up in a restoration plan may include:

- Purchase and strategic storage of material caches, spare all-terrain equipment to access remote sites. Material for caching may be purchased with the primary material orders to take advantage of bulk costing.
- Development of an access and restoration trail-way system. This should be done during primary construction.
- Design of temporary emergency structures and anchoring devices which may be flown in to remote tower sites.
- Mutual aid agreements with neighbouring utilities.

2.4.8 Summary

The following is a summary of the key findings from the review of the information gathered and interviews held with the Nalcor project team.

The Nalcor project management team is utilizing an experienced consultancy firm to prepare the detailed design, material, and construction cost estimate taken forward to Decision Gate 3. Nalcor is utilizing professional staff with engineering and project management backgrounds to manage, track, and direct the consultant using accepted project management practices.

The design and construction schedule proposed by Nalcor is achievable provided there are no major changes to the project scope, unusual weather encountered during construction seasons, and adequate contractors are retained with resources available.

In its evaluation of the conductor optimization and selection report prepared by SNC Lavalin, MHI noted to Nalcor that the report did not examine in sufficient detail the reliability issues of the recommended conductor operating in the severe icing regions through the Long Range Mountains. Nalcor has indicated a study of this technical issue is underway to examine the use of extra high-strength aluminum alloy conductors in these regions. The approximate 20% cost premium for these conductors is not included in the Decision Gate 3 estimate, but since the severe icing regions represent only 15% of the transmission line length, the impact to the total project budget if the alloy conductor is implemented is negligible.

In MHI's opinion, Nalcor has undertaken a diligent and appropriate approach to design the transmission line to withstand the many unique and severe climatic loading regions along its line length. MHI continues to support selecting a 1:150 year climatic return period due to the criticality of the HVdc transmission line to the Newfoundland/Labrador electrical system.

MHI recommends that Nalcor develop a transmission line emergency response restoration plan prior to in-service which includes consideration of access routes, material caches and equipment which can be mobilized in an emergency.

The transmission line structures and routes selected for all transmission facilities are cost-effective considering the terrain, route, and climatic loading expected. From the review of the written documentation provided, design methodology, and information recorded in the Nalcor staff interviews, MHI has found that the Decision Gate 3 estimates for all transmission facilities were prepared in accordance with good utility practice and within an AACE International Class 3 level accuracy range.

2.5 Strait of Belle Isle Marine Crossing

The configuration of the Strait of Belle Isle (SOBI) cable crossing has not changed significantly from prior studies.

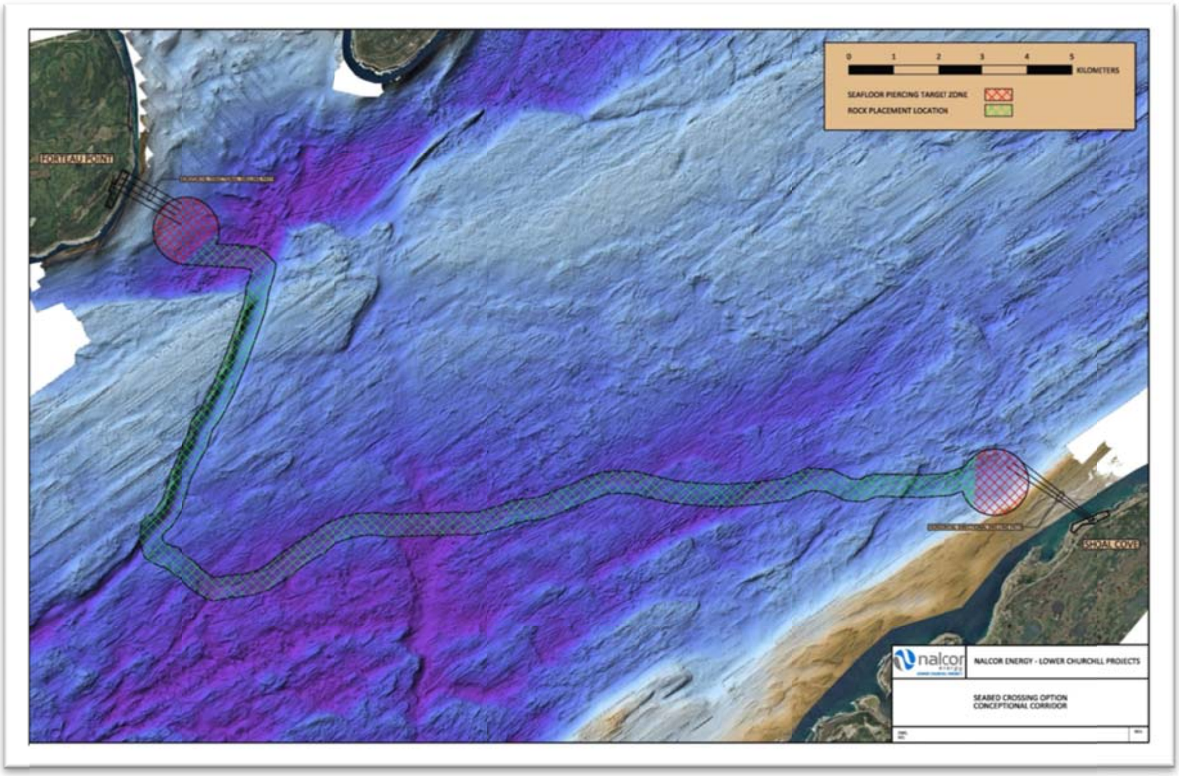


Figure 10: Strait of Belle Isle Marine Crossing Location

Further refinement of the route is being investigated to firm up the shore approaches, the horizontal directional drilling (HDD) techniques, the sea floor routing, the cable-laying technology, and the rock berm placement. There are ongoing studies of the currents and tides in the Strait, and continued surveillance of iceberg movements and roll rates in the vicinity. An observation tower has been erected to track movement of icebergs through the Strait and record actual roll rates. The status of these works was reviewed during meetings with Nalcor for this segment of the project.

2.5.1 Decision Gate 3 Activities

Significantly more knowledge has been gleaned in all aspects of the marine crossing project. There have been ongoing discussions with the potential cable suppliers, the cable has been tendered and a contract award is imminent. A decision has been made to embed fibre-optic cable for communications into the submarine cable, which increases the cost of the cable but results in an overall net reduction in this segment of the project.

Considerable work has also been done with cable-laying contractors, rock berm contractors and a test HDD bore hole was drilled from the Shoal Cove Landing site on Newfoundland for a distance of approximately 1,500 m. Drill rates were assessed during this test and were slightly longer than previous estimates. Some problems were encountered with fractured rock but grouting procedures proved workable. The bore hole was reamed out to 14 in. in some areas and 24 in. in others without any significant problems. These diameters are a specified requirement for the steel liner to be placed. It may be possible that the other two bore holes may be drilled at a lower depth to prevent the intersection of the fractured rock and subsequent requirement for grouting. Although the bore hole was not completed to the subsea floor, it is very likely that drilling re-entry will be done and the test hole used for one of the three cables.

From discussions with potential installers, it is expected that the laying of the cable on the sea bed can be completed in approximately 45 days. Iceberg flows typically prevent a start-up of work in the Strait until at least June 1. The work season in the area usually extends to late October so there appears to be ample time to complete this work in one summer season, rather than the two-year program originally envisioned.

If in fact the project is completed and the HVdc lines and converter stations are in service by the fall of 2016, it may be possible to transmit power imported from the market with significant savings in fossil fuels at the Holyrood Generation Station.

It has been determined that all of the cables can be placed on the laying vessel, reducing the time required to reload during the installation exercise. It is expected that the cable can be floated at the Labrador side and a joint made on board the laying ship with the cable from the shore approach.

Discussions with potential rock berm suppliers are underway to optimize the design. Information has also been made available from suppliers on a new technique for removing the rock from the berm should it be necessary to facilitate a repair to the cable. This new method would involve vacuuming the rock off the berm, allowing removal of rock up to 16 inches in diameter. Several qualified Canadian contractors have been trained in the use of this equipment.

2.5.2 Schedule and Estimates

The cable for the 32 km crossing has been tendered and three bids have been received. Suppliers have quoted firm prices in Canadian dollars for cable delivery in 2015-2016. The inclusion of the fibre-optic cable would result in a reduction in costs while improving reliability rather than relying on line-of-site communication towers on either side of the Strait.

The conductor was originally specified at 320 kV and has subsequently been upgraded to 350 kV. The increase in operating voltage will result in minimizing line losses and improve the business case for the higher voltage cable. The larger conductor will also support an increased pull-in-load to better facilitate installation.

The land-trenching costs are likely to be somewhat higher than previous estimates based upon the observed rate of progress on the test bore hole and unit costs for construction.

There are also several opportunities to reduce costs from previous estimates. There may be potential to shorten the crossing distance following a more detailed engineering design. A request for proposal for the rock berm is scheduled to be issued at the end of summer 2012 which will firm up both the quantity and cost of rock to be placed.

It may also be possible to reduce the planned size of the HDD bore hole. Any reduction in size will increase drill rates, shrink the size of the steel liner and therefore lower the overall cost of the SOBI crossing. The SOBI cable crossing has been adequately redefined in Decision Gate 3 and the planned approach to the project optimized. While there has been an increase in overall costs, there have also been several opportunities noted for possible reduction in costs.

MHI considers the project construction schedule to be reasonable but all onshore and HDD should be completed in advance of receipt of the cable.

2.5.3 Summary

The costs of the Strait of Belle Isle marine crossing have increased marginally but are considered to be reasonable and within the AACE Class 3 estimate range for Decision Gate 3. MHI is of the opinion that there is an equal likelihood that the costs will decrease, as a result of opportunities through optimized design.

2.6 Muskrat Falls Generating Station Development

In January, 2012, Manitoba Hydro International submitted the "Report on Two Generation Expansion Alternatives for the Island Interconnected Electrical System"[4], which included a review of Nalcor's Muskrat Falls Generating Station plans from the perspective of technical and construction feasibility and cost estimate. This review covers Nalcor's work in preparation for Decision Gate 3 and is also based on information provided by Nalcor in June, 2012.

This section of the report describes the schedule and cost implications of the Muskrat Falls Generating Station including ac Switchyard Upgrades and Transmission Lines to Churchill Falls.

2.6.1 Scope of Work

A high-level review of the Muskrat Falls Generating Station design changes, associated switchyards, and 315 kV transmission lines to Churchill Falls was completed. Cost estimates and construction schedules completed by Nalcor in preparation for Decision Gate 3 were examined and an assessment was made of their reasonableness as inputs to a CPW analysis. Nalcor provided a number of documents to assist MHI in this review.

2.6.2 Muskrat Falls Generating Station

Design and Engineering

The evolution of project scope based on further engineering includes the following:

- Reorientation of the powerhouse in the river by approximately 30^0
- The spillway configuration change from a four-radial gate to a five-vertical gate arrangement
- A significantly more massive powerhouse intake structure
- The south dam changed from a roller-compacted concrete (RCC) structure to a rock fill dam
- The addition of a second service bay at the north end of the powerhouse
- The addition of an RCC cofferdam to the bulk excavation work contract.

From discussions with the Lower Churchill Project (LCP) team and a review of selected change management documents, the changes in project scope are based on sound

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[4] Web link, http://www.pub.nf.ca/applications/MuskratFalls2011/MHIreport.htm

engineering principles and have been effectively incorporated into the current project schedule and budget.

The Lower Churchill Project team has demonstrated in documents provided to MHI by Nalcor that the overall design and engineering for the project was 40% complete at the time of submission. Although a comprehensive review of the design was not within the scope of this review, the level of detail provided and evidence in the selected samples of the schedule and budget information supports this degree of completion.

The design and engineering conducted to date are appropriate for a Decision Gate 3 milestone.

2.6.3 Schedule

The target schedule indicates:

- Project start fourth quarter 2012
- Revisions to work package timing and durations as a result of design and engineering changes and refinements
- First power date is July 2017.

The high-level schedule that was reviewed reflected the project contracting strategy and depicted the key project activities that impact the project schedule. The schedule is consistent with the current contract packaging strategy and has considered labour workforce levelling. Based on a selected review, the schedule is supported by a very detailed work breakdown structure that should address project and construction management, and cost control during project execution.

There are a few areas in the schedule that will be challenging, for example, early installation of the project infrastructure, RCC cofferdam construction, and the main structures concrete. In discussion with the project team, however, it is apparent that they are well aware of these issues and are taking measures to manage the risks associated with the components of the schedule.

From MHI's perspective, the project scheduling is comprehensive, detailed, and consistent with best industry practice for similar projects. The current project schedule is appropriate and reasonable to meet the requirements of Decision Gate 3.

2.6.4 Cost Estimates

For Decision Gate 3, the Muskrat Falls Generating Station project cost estimate increased by 21% after allowing for a decrease of escalation and contingency funds in 2012.

The Decision Gate 3 estimate incorporates the recent design changes and is based on upgraded quantities derived from design development, recent pricing and quoting from suppliers, and updated labour pricing.

The Muskrat Falls Generating Station project contingency in the Decision Gate 3 estimate is 9.0%, but maybe higher with allowances if required. This has been discussed with the Nalcor project team, and the Nalcor project team believes that the current Decision Gate 3 estimates input detail and conservative assumptions justify the chosen contingency amount. Nalcor has noted that there is fixed pricing in place for approximately 25% of the project value, thus the 9% contingency is reasonable for Muskrat Falls Generating Station.

Based on the amount of engineering and levels of costs provided, MHI considers the Decision Gate 3 cost estimate to be an AACE Class 3 estimate and therefore would be considered reasonable for the Decision Gate 3 project sanction stage.

2.6.5 Labrador Transmission Assets

The Labrador Transmission Assets (LTA) includes the 315 kV transmission lines from Muskrat Falls to Churchill Falls, and the switchyards at both Muskrat Falls and Churchill Falls.

The evolution of project scope based on further engineering includes the following:

- The inclusion of the 735 kV equipment into the Churchill Falls Switchyard, which had previously been attributed to the Gull Island Generating Station project
- The power lines from the powerhouse unit transformers to the switchyard were changed from underground cables to overhead lines. This change was due to the reorientation of the powerhouse by approximately 30° with the river bed. This allows for a more conventional overhead line arrangement and which would be advantageous from both cost and schedule perspectives.

The current LTA schedule (i.e. 315 kV transmission line) has a projected in-service date of May 2016.

The schedule, which is 33 months long and includes three winter construction periods, accounts for the clearing and construction of the 247 km long 315-kV transmission line. This is a prudent and reasonable schedule given the length of line, the location, and the potential for unusual weather conditions. The schedule durations for AC switchyard design and construction, and procurement of the required transformers and switchgear appear reasonable.

The LTA estimate increased significantly with Decision Gate 3 as a result of including the new 735 kV equipment at the Churchill Falls Switchyard, utilizing current international instead of local construction costs, and increased indirect costs such as construction camps. In consideration of the anticipated significantly increased transmission line construction activity across Canada over the planned period, the increased estimates for construction costs and construction camps are considered appropriate. The LTA Decision Gate 3 estimate includes a 9.1% contingency which is reasonable when combined with conservative inputs on labour and indirect costs. ***Overall the Labrador Transmission Asset Decision Gate 3 estimate is comprehensive, reasonable and prepared in a manner consistent with best utility industry practice***.

2.6.6 Summary

The Lower Churchill Project team developed a comprehensive work breakdown structure for the Muskrat Falls Project that is consistent with the proposed contracting strategy. It is detailed enough to support a Decision Gate 3 level review of the scope, schedule, and budget, and to provide a framework for managing the project going forward.

The Lower Churchill Project has utilized experienced consultants, well recognized independent construction specialists and benchmarking of other recent projects to confirm constructability, productivity rates, and costs. This work, combined with the advancement of the design to the 40% level at the time of submission, provides a significant increase in confidence in the Decision Gate 3 schedule and cost estimate.

From a review of the information provided, Nalcor has performed the design, scheduling and cost-estimating work for the Muskrat Falls Generating Station and the Labrador Transmission Assets with the degree of skill and diligence required by customarily accepted practices and procedures utilized in the performance of similar work. The current Lower Churchill Project design, schedules and cost estimates are considered consistent with good utility practice. The design, construction planning, cost estimate and schedule are comprehensive and sufficiently detailed to support a Decision Gate 3 project sanction and appropriate for input into a cumulative present worth analysis.

3 Isolated Island Option

3.1 Load Forecast

The purpose of this section is to compare the forecasts prepared for the 2012 Isolated Island option and the 2012 Interconnected Island option. The Isolated Island option is based on a higher marginal electricity price because the cost of future generation is more expensive driven by escalating fuel costs. The higher marginal electricity price is expected to reduce future electricity consumption by encouraging conservation and discouraging electric space-heating installations, which will reduce or delay the need for future generation additions.

3.1.1 Comparison of the 2012 Isolated Island option and 2012 Interconnected Island option

The energy and peak forecasts for the Isolated Island option are lower than the respective forecasts for the Interconnected Island option (see Figure 11 and Figure 12). These differences are maximized by 2045, when the Isolated Island option energy forecast and peak forecast are lower by 487 GWh and 86 MW, respectively. After 2045, the gap narrows so that by 2067, the Isolated Island option energy forecast and peak forecast are lower by 276 GWh and 44 MW, respectively.

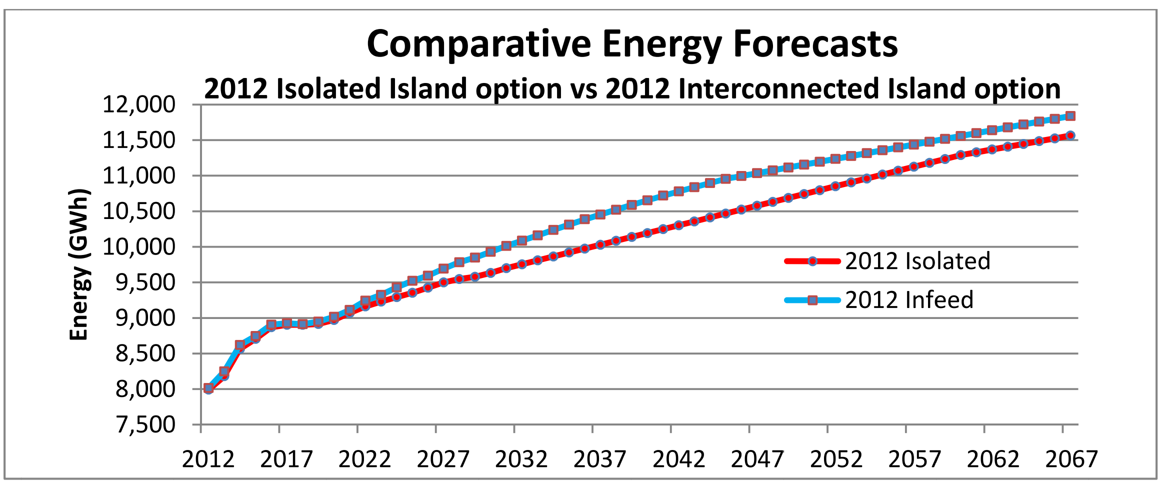

Figure 11: Comparative Energy Forecasts – The 2012 Isolated Island option versus 2012 Interconnected Island option

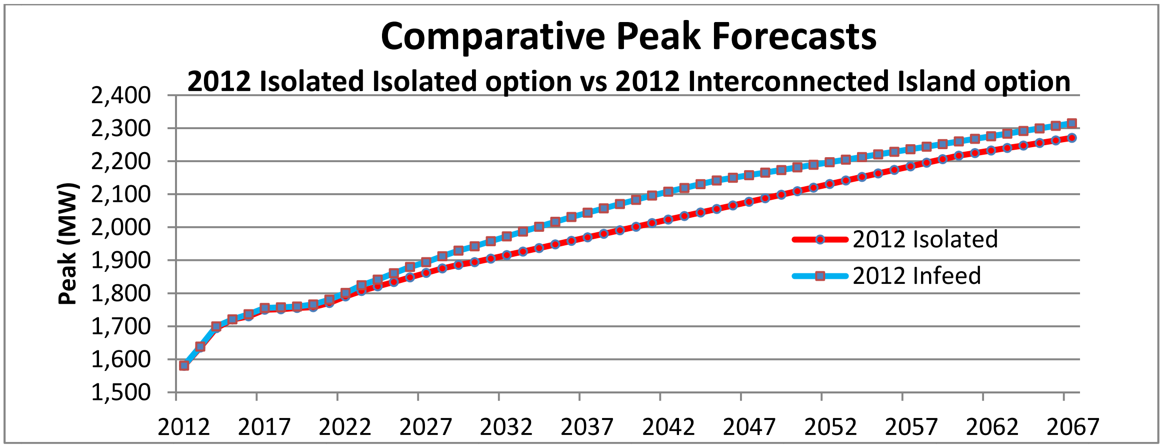

Figure 12: Comparative Peak Forecasts – The 2012 Isolated Island option versus 2012 Interconnected Island option

Table 8 demonstrates that the energy and peak differences between the two options are minimal in 2012. The main cause for the difference in energy consumption is energy reductions in the domestic sector. The general service and other load reductions are minimal throughout the forecast. There is no difference in the industrial load because both options use the same forecast.

Table 8: Comparison of the 2012 Isolated Island option and the 2012 Interconnected Island option – Net Differences

	Energy (GWh)					Peak (MW)
Year	Domestic	General Service	Industrial	Other	Energy	Peak
2012	-13	-6	0	-2	-21	0
2020	-48	-1	0	3	-46	-8
2029	-257	-4	0	-7	-269	-43
2045	NA	NA	NA	NA	-487	-86
2067	NA	NA	NA	NA	-276	-44

The reduction in the domestic forecast occurs because the Isolated Island option is based on a higher marginal electricity price. The higher marginal electricity price is due to the future generation for the Isolated Island option being more expensive than the Interconnected Island option. The higher marginal electricity price reduces the usage of electricity by encouraging conservation and by discouraging the installation of electric space-heating systems. By 2029, the difference in marginal electricity price is 1.13 cents, creating a 928 kWh reduction in domestic average use and a 257 GWh reduction in domestic load.

For both options, the extrapolated forecast assumes that the rate of new electric space-heating loads will be reduced after the 20-year forecast period. Since there is less electric space-heating load in the Isolated Island option, less energy is allocated each year, which widens the energy gap until 2045. By 2045, the Interconnected Island option reaches the maximum constraint for saturation of electric space-heating. The Isolated Island option does not reach the maximum constraint and continues to capture new electric space-heating load beyond 2045, which causes the energy gap to diminish over the later years of the extrapolated forecast period.

3.1.2 Comparison of 2012 Isolated Island Option to Historical Growth

Table 9 compares the 2012 Isolated Island option to historical growth. Total Island energy and peak requirements are expected to grow at a steady rate over the next 20 years. The 20-year Island energy forecast growth rate is 100 GWh and the 20-year Island peak forecast growth rate is 18 MW. These forecasts assume no industrial closures, but the forecast growth rates are still lower than the growth experienced over the last 40 years, which has been adversely affected by pulp and paper mill closures.

Table 9: Annual Growth per Year – Historical Growth and the 2012 Isolated Island option

Sector	Historical Growth Rate			Isolated Island option	
				Forecast Growth Rate	Extrapolated Growth Rate
	1971-2011 (40-Year)	1991-2011 (20-Year)	2001-2011 (10-Year)	2011-2031 (20-Year)	2031-2067 (36-Year)
Domestic (GWh)	77	42	65	42	NA
General Service (GWh)	44	24	32	21	NA
Industrial (GWh)	-13	-58	-132	31	NA
Other (GWh)	8	3	13	6	NA
Island Energy (GWh)	117	12	-23	100	52
Island Peak (MW)	25	3	11	18	10

The 20-year forecast growth rate for the domestic sector (42 GWh) is expected to be the same as the 20-year historical growth rate, which included the economic downturn of the 1990s, and 45% lower than the 40-year historical growth rate (77 GWh). MHI considers the domestic forecast for the Isolated Island option to be overly conservative. The general service, industrial, and other sector forecasts are similar to the 2012 Interconnected Island option, which is discussed earlier in this report, Section 2.1.

3.1.3 Summary

Similar to the findings in the 2012 Interconnected Island option (Section 2.1.4), the primary concern with the 2012 Isolated Island option is that the total Island energy and peak forecasts over the extrapolation period are too low. The extrapolated energy forecast is only 52% of the load expected over the next 20 years. The extrapolated peak forecast is only 56% of the load expected over the next 20 years. These reductions in future growth are significant and may be overly conservative. The extrapolated growth rates are significantly lower due to lower domestic average use, lower electric space-heating saturation, and the assumption of no new industrial loads locating on the Island over the extrapolation period.

3.2 Holyrood Thermal Generating Station

There are a number of alternates for Holyrood Thermal Generating Station, some of which only apply for the Interconnected Island option, some for the Isolated Island option, and some for both options. As most of the plans have been fully documented in the Decision Gate 2 review report, only the changes in scope or costs are noted as part of this report.

The most significant sources of greenhouse gas (GHG) emissions are anthropogenic (or human impact) mostly as result of the combustion fossil fuels. In December 2009, Canada committed to a national greenhouse reduction of 17% below 2005 levels by 2020. Then in June 2010, the government of Canada announced it would take action to reduce carbon dioxide greenhouse gas emissions in the electricity generation sector with regulations on fossil fuels generation. The Government specifically targeted the coal burning sector of the industry but oil burning regulations will not be far behind. The Holyrood Thermal Generating Station emits in excess of 1 million tonnes per year of GHG's. The installation of scrubbers and NO_X burners at a cost in excess of $600 million will clean up particulates and SO_X but will not remove carbon dioxide. Therefore, Holyrood Thermal Generating Station could become a target for Federal Government regulation well in advance of the end of its useful life of 2035. The final regulation for reducing GHG emissions from coal-fired electricity generation were announced by Canada's Environment Minister, the Honourable Peter Kent, on September 5, 2012. Again there was no mention of oil-fired generation but certainly greenhouse gas emissions from oil certainly mirror those from coal.

3.2.1 Holyrood Pollution Control Upgrade

As part of the Isolated Island base case for Decision Gate 3, sulphur dioxide scrubbers (flue gas desulphurization) and particulate collection devices (electrostatic precipitators) were considered to be installed by 2018 and maintained for the economic life of the plant until 2035. Stantec Consulting Ltd. (Stantec) provided an update to the costs outlined in the previous study conducted in 2008.

Findings for Decision Gate 3

Stantec performed a thorough review of the probable cost of the project to the current economic conditions in Newfoundland and Labrador. Stantec also reviewed any changes to environmental regulations that may have occurred that would impact the findings in the original report. Stantec used information from Statistics Canada, Consumer Price Indices for

Newfoundland and Labrador, economic indicators, and Engineering News Records to establish an estimated revised cost.

The productivity factor for labour used in the 2008 Report was still considered appropriate for this study. However, Newfoundland and Labrador are currently experiencing a shortfall of skilled labour due to the increase in construction activity in the region. This is putting pressure on labour rates which were called up to more adequately represent the trend in the construction timeframe. Material prices are somewhat higher in 2012 versus 2008, and despite steel prices being lower overall there was a slight increase in the price allowed for materials.

The review of major equipment and subcontracts concluded that equipment has increased in price equivalent to inflation while the subcontract price of labour and installation has increased significantly.

Summary

The Stantec study concluded that the overall cost to add the scrubbers and precipitators to the Holyrood Generating Station has increased but is generally in line with inflation. The costs outlined in the new report are appropriate for use in the Decision Gate 3 CPW analysis for the Isolated Island Option.

3.2.2 Holyrood Life Extension and Decommissioning

The Holyrood Life Extension was re-evaluated by AMEC in the spring of 2012 to update the prior estimate. The assumption of retaining the thermal generation plant at a capacity factor of 75% is similar to what was envisioned in previous work. Holyrood was the only station evaluated and the study did not examine any additional thermal plants.

Findings for Decision Gate 3

Decision Gate 3 considers continued operation of Holyrood in the Isolated Island Option with plant refurbishments in 2017, 2022, 2027 and 2032, operating until 2035. The reliable operation of all three units was assumed. Plant staffing and contract maintenance was assumed to be equivalent to current levels. In both cases, sulphur dioxide scrubbers (flue gas desulfurization – FGD) and particular collections devices (electrostatic precipitators – ESPs) were considered to be installed by 2018, and maintained for the economic life of the plant. High operating reliability and availability will be required in both cases.

A typical near end-of-life refurbishment would be in the range of $400/kW or $200 million for Holyrood, excluding the costs for the FGD and ESPs. The FGD would likely need to be refurbished in the 2023 to 2027 time range and is estimated to cost approximately $80/kW or $40 million.

Some additional FGD start-up costs and annual capital expenditures of $2 million/year were also likely. A modest refurbishment would occur in the 2025 time frame. The timing of the Holyrood refurbishment would likely be staged from 2013 to 2017. This would allow the plant to continue to provide reliable service and capacity. A second minor refurbishment would also be staged in the 2024 to 2026 time period.

For the Interconnected Island option, Holyrood unit 3 is maintained as a synchronous condenser after the Labrador-Island HVdc link comes online. These costs represent a combination of sustaining capital and decommissioning costs for Holyrood operating as synchronous condensers. The base document for life extension and decommissioning estimation was the Holyrood 20 year capital plan which outlines the Holyrood complex requirements itemized in the CPW analysis as CP2 through to CP5.

Summary

The AMEC study essentially updated the prior Holyrood Thermal Generating Station life extension plan for the Isolated Island option by bringing forward estimates to Decision Gate 3. The costs allocated to the CPW analysis for the Interconnected Island option are of sufficient scope to operate Holyrood unit 3 as a synchronous condenser.

3.2.3 Holyrood Thermal Generating Station Replacement

For the Isolated Island option, the Holyrood Thermal Generating Station plant replacement is planned to consist of three, 170 MW No. 2 low sulfur oil-fired CCCTs. The replacement turbines would be installed in 2032, 2033 and 2036.

3.3 Wind farms

MHI has been studying the proposed wind plan for inclusion into the Isolated Island option, as a separate project. The report of this study is published under separate cover "Decision Gate 3 Review of the Wind Study for the Isolated Island of Newfoundland" [5]. The new generation master plan allows for up to 279 MW in total wind capacity on the Island as part of the Isolated Island option.

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[5] Manitoba Hydro International Ltd. "Decision Gate 3 Review of the Wind Study for the Isolated Island of Newfoundland", September 2012.

The two wind farms proposed in the prior generation plans (St. Lawrence and Fermeuse) were updated to reflect current costs. There was no wind in the Interconnected Island option and none has been added in advance of Decision Gate 3.

Findings for Decision Gate 3

The original Isolated Island option generation master plan (November 2010) included the replacement of St. Lawrence and Fermeuse wind farms in 2028 and 2048 and a new 25 MW wind farm in 2014 with replacement in 2034 and 2054. The revised Isolated Island generation master plan retains all three of the wind farms but also adds a further 50 MW of wind in 2020, 2025, and 2030 including replacements on a 20 year basis plus a 25 MW wind farm added in 2035 and replaced in 2055. This additional 225 MW of wind displaces some base load thermal generation with associated fuel savings.

The Fixed Charges in capital cost estimates, and Operating & Maintenance costs estimates follow industry benchmarks escalated to 2012 dollars and are reasonable as inputs in to the CPW base case analysis.

Summary

MHI has reviewed the costs associated with the fixed charges and operating expenses and find them reasonable as inputs into the CPW analysis.

3.4 Simple and Combined-Cycle Combustion Turbines

The thermal generation facilities considered for both the Isolated Island and Interconnection Island options did not change for Decision Gate 3. The Acres International studies of 1997 and November, 2001 had been used to develop a scheme of simple-cycle combustion turbines (CTs) and combined-cycle combustion turbines (CCCTs) for the Island, at the existing Holyrood site or a new greenfield location. These studies were updated in April, 2012 by Hatch to reflect the current cost and operating environments of both a 170 MW combined cycle and 50 MW simple cycle units.

Findings for Decision Gate 3

In 1997, Acres International and Stone & Webster conducted a feasibility study to install combustion turbines at the Holyrood Generating Station. This original study considered various combined-cycle plants between 150 and 200 MW. The study concluded that natural gas would be unavailable and heavy fuel was eliminated due to excessive maintenance requirements and engine performance derating. Thus the early decision was to fuel the plants using diesel. A two pressure non-reheat cycle was selected and a single turbine configuration was chosen.

In 2001, the study was updated for combined-cycle plants in two capacity ranges, 125 MW and 175 MW. The update included data on plant performance, project capital costs, project schedules, operating and maintenance cost updates and environmental impacts. These costs were then escalated using appropriate indices for use in Decision Gate 3 estimates.

Hatch's 2012 study evaluated the costs for both the 170 MW combined cycle and the 50 MW simple cycle units. However in this case, budget prices were solicited from vendors for major equipment including delivery schedules. In some instances values were updated based on factoring from previous projects.

Summary

MHI finds that the methodology used to develop revised estimates for CT and CCCT thermal generating plants were reasonable and reflects state of the art industry practices for a project at the Decision Gate 3 level.

3.5 Small Hydroelectric Plants

3.5.1 Island Pond and Portland Creek Generating Station Development

The configuration of the Island Pond Generating Station and the Portland Creek Generating Station developments remained unchanged for Decision Gate 3. SNC Lavalin had conducted a detailed project design and engineering analysis in 2006[6]. This study was updated in April, 2012 to reflect the current cost and operating environments.

Findings for Decision Gate 3

As the design and engineering for Decision Gate 3 did not change, a group of relevant escalation indices were tabulated, and a composite index was prepared for the years 2006 and 2012. The resulting escalation index, representing the general cost increase from 2006 to 2012, was applied to all of the unit prices and a revised lump-sum price was established.

Schedule and Cost Estimate for Decision Gate 3

The escalated unit and lump-sum pricing was compared to equivalent pricing from other similar projects. When it was found that the comparative pricing differed significantly with the escalated project pricing, an adjustment was made to the escalation index for that price in the updated project cost estimates. Where practical, such as gate and hoist equipment, an evaluation was made of estimated weights for equipment and applicable unit prices to determine a rational price.

No consideration was given to a premium which could reflect the current state of construction labour in Newfoundland and Labrador.

Unit prices for both Portland Creek and Island Pond hydroelectric projects are in many cases the same for equivalent work items. There are exceptions where there are different foundation conditions from one project to the other.

Summary

The approach chosen to update the estimates on both the Island Pond Generating Station and Portland Creek Generating Station projects is reasonable given the static nature of the design and engineering. ***The revised costs for the small-hydro plants Island Pond and Portland Creek are suitable as an estimate for input into Decision Gate 3.***

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[6] Exhibit 5b, SNC Lavalin, "Studies for Island Pond Hydroelectric Project", December 2006

3.5.2 Round Pond Generating Station

The Round Pond Generating Station development was initially investigated by Acres International in 1985, and the concept was updated in a feasibility study conducted by Shawinigan/Fenco in 1987/1988. Newfoundland and Labrador Hydro undertook companion studies of transmission, telecontrol, and environmental issues, and issued a Summary Report in February, 1989 incorporating the findings from the Shawinigan/Fenco investigations. Hatch Consultants updated costs in April, 2012 to reflect current cost and operating environments. This study was used for the Decision Gate 3 analysis.

Findings for Decision Gate 3

Hatch updated the initial cost estimates by applying its own proprietary estimating package to unit prices for all civil works. Hatch applied labour rates based on current labour agreements applicable to the 2012 market environment in Newfoundland and Labrador. The equipment rates were based on leasing of equipment by contractors, with consideration for the present heavy schedule of projects in the province. This approach was considered to be reasonable, although different than the approach used for both the Island Pond Generating Station and Portland Creek Generating Station developments.

Schedule and Cost Estimates for Decision Gate 3

Electrical and mechanical direct costs include the purchase and installation of turbine and generator equipment, and all mechanical and electrical equipment including gates, guides, and hoists. Estimates for mechanical equipment are based on Hatch's database of applicable contract and tender pricing combined with appropriate escalation and rating adjustments to match the Round Pond Generating Station technical parameters and estimate date. Indirect costs were also sufficiently covered.

Summary

The approach selected by Hatch Consultants to update the original studies is reasonable given the static nature of the design and engineering. ***The revised costs for Round Pond are a reasonable estimate suitable for input into Decision Gate 3.***

4 Financial Analysis of Options

4.1 Cumulative Present Worth Analysis

The Cumulative Present Worth (CPW) approach is an acceptable method by which to measure the present worth of alterative options. It focuses only on costs, including capital expenditures for the construction of new facilities, operating costs, fuel costs, and the cost of purchased power. The CPW approach does not take into account cash inflows related to revenues. The preferred option is the outcome which minimizes the cumulative present worth of costs considered over the study horizon.

The CPW approach provides discrete outcomes based on a relative set of input values. When undertaking this analysis, it is appropriate to also consider alternative outcomes. To this extent, a number of scenarios were developed for comparison to the base reference case.

Two base case options were considered by Nalcor, those being the Isolated Island option and the Interconnected Island option. From the perspective of the base reference case, the CPW for the Isolated Island option is $10,778 million, while in contrast the CPW for the Interconnected Island option is $8,366 million. The CPW of projected costs for the Interconnected Island option is $2,412 million less than the Isolated Island option, making it the more attractive option of the two under consideration.

The CPW for each of the two options is comprised of four main inputs:

- Fixed Charges
- Operating Costs
- Fuel Costs
- Power Purchase Costs

Costs for each of the four inputs have been quantified on an annual basis for the period extending to 2067. The sum of the input costs across the various years have then been discounted to 2012 based on a discount rate of 7.0%. The Interconnected Island option includes the benefit of the federal loan guarantee.

4.2 CPW Results

A summary of the four inputs for the CPW for each of the two options is included in the Table 10 below.

Table 10: Comparison of Options by major input category

Comparison of CPW Estimates for the Two Supply Options					
Major input category	Interconnected Island option		Isolated Island option		Difference
	CPW ($ 000s)	%	CPW ($ 000s)	%	
Fixed Charges	319,400	3.8	2,555,943	23.7	(2,236,543)
Operating Costs	258,939	3.1	752,448	7.0	(493,509)
Fuel	1,320,530	15.8	6,706,178	62.2	(5,385,648)
Power Purchases	6,467,127	77.3	763,770	7.1	5,703,357
TOTALS	**8,365,997**		**10,778,339**		**(2,412,342)**

It is notable that the Fuel Costs under the Isolated Island option account for 62.2% of the total CPW value whereas under the Interconnected Island option, the Fuel Costs account for only 15.8% of the total CPW value. This is attributed to the approximately 45 company owned thermal generation facilities, including the extended life for Holyrood under the Isolated Island option. Table 11 below highlights the fuel consumption between the two options.

Table 11: Fuel consumption between the two options

Barrels ('000)	Isolated Island option	Interconnected Island option
# 2 Fuel	121,632	1,213
# 6 Fuel	61,509	13,398
TOTAL	**183,141**	**14,611**

In contrast however, the early capital investment outlay for the Interconnected Island option is much greater than that for the Isolated Island option. To make a comparison of the CPW for each, it is appropriate to combine the CPW results related to the Fixed Charges with the Power Purchase Costs, as set out in Table 12 below. The greater CPW value and relative percentage related to the Interconnected Island option is attributed to the substantial capital investment tied up in the development of the Muskrat Falls generating station and the capital investment required for the building of the transmission line linking the plant from Labrador to Soldiers Pond.

Table 12: Fixed and PPA charges compared to Total

CPW (000s)	Interconnected Island option	Percent of Total CPW	Isolated Island option	Percent of Total CPW
Fixed Charges	319,400	3.8%	2,555,943	23.7%
Power Purchase Costs	6,467,127	77.3%	763,770	7.1%
TOTAL	**6,786,527**	**81.1%**	**3,319,713**	**30.8%**

4.3 Fixed Charges

The Fixed Charges are related to investment in plant and are intended to capture:

- Depreciation expense based on capital expenditures
- Return on Investment in Plant
- Insurance

The Depreciation Expense is based on the In-Service cost of the plant spread over its expected useful life. The Return on Investment in Plant has been calculated assuming a Return of 7.0% on the undepreciated portion of plant over its useful life. Based on documents provided to MHI by Nalcor, insurance has been calculated assuming a rate of 0.03 percent also on the in-service capital costs of the plant over its useful life.

With respect to the determination of the In-Service cost of plant, the projected total plant cost which has been denominated in 2012 dollars has been escalated each year for the work completed that year, over the period during which the plant is under construction. The escalation factor is designed to take into account factors such as productivity, market conditions, labour force etc. In addition, an Allowance for Funds Used During Construction (AFUDC) has been charged at a rate of 6.25% for the period during which the proposed plant is under construction, recognizing the construction of plant facilities extends beyond one year.

4.4 Operating Costs

The Operating Costs are comprised of two components:

- Fixed Operating and Maintenance (O&M)
- Variable Operating and Maintenance (O&M)

A fixed O&M cost has been determined for each different type of generating facility, expressed in 2012 dollars. For example, all 50 MW CT plants have an annual fixed cost of $551 thousand whereas all CCCT 170 MW plants have an annual fixed cost of $2,550 thousand. Based on documents provided to MHI by Nalcor, the fixed costs have been escalated at a rate of 2.5% forward to the date of in-service for each plant and each year thereafter.

Similarly, a variable O&M cost expressed as dollars per MWh has been determined for each different type of generating facility, expressed in 2012 dollars. The unit rate is applied to the production for each facility. These costs have been escalated as well at a rate of 2.5% forward to the date of in-service for each plant and each year thereafter.

The combined fixed and variable operating costs have then been discounted to 2012 based on a discount rate of 7.0%.

4.5 Fuel Costs

The Fuel component of the CPW incorporates two types of fuel:

- No. 2 Fuel used in CT and CCCT generating units.
- No. 6 Fuel used exclusively at the Holyrood Thermal Generating Station.
  - 0.7% sulphur
  - 2.2% sulphur

The No. 2 fuel is used throughout the period under review to 2067. The No. 6 fuel 0.7% is phased out in 2018 for the Interconnected Island option and in 2036 for the Isolated Island option.

The unit fuel costs are based on a May 2012 PIRA Energy Group (PIRA) forecast from 2012 forward 18 years to 2030, after which Nalcor has inflated the unit prices of fuel at 2.0% per year, compounded.

The combined fuel costs have then been discounted to 2012 based on a discount rate of 7.0%.

4.6 Power Purchase Costs

The Power Purchase Costs differ substantially between the two options.

Isolated Island option

For the Isolated Island option, Power Purchase Costs represent the power purchased from non-utility generators. The Cumulative Present Worth of the power purchased from these sources under this option is $763.8 million. This power is required in addition to the power generated by a number of company owned facilities which will be built during the period under review. The company owned facilities include a variety of Wind, Hydro, Combustion Turbines, Combined Cycle Combustion Turbines and the existing Holyrood facility. Apart from Holyrood, the facilities range in size from 25 MW to 170 MW. The costs to operate the company owned facilities are included under the headings of Fixed Charges, Operating Costs, and Fuel Costs.

Interconnected Island option

The major difference for the Interconnected Island option is the inclusion of the costs relating to the Muskrat Falls generating facility and the Labrador-Island HVdc transmission link. The derivation of the CPW for the Labrador-Island HVdc link is similar to the calculations for each of the variety of the smaller generation units. The CPW related to the Labrador-Island HVdc link is $2,188.6 million.

The derivation of the CPW for the Muskrat Falls generation facility follows a different approach. A Power Purchase Agreement (PPA) approach has been used whereby NLH will sign a take-or-pay contract with Nalcor with the expectation that Nalcor will receive its pre-determined revenue over the life of the asset based on the volumes of energy delivered. The monetization of any power generated by Muskrat Falls in excess to the needs of Newfoundland and Labrador Hydro, will accrue to Nalcor.

The unit PPA rate was determined assuming a threshold Internal Rate of Return (IRR) of 8.4% based on 65% debt/35% equity financing. The proposed PPA unit rate is $65.38/MWh expressed in 2010 dollars. The PPA rate is then escalated at 2.0% per year over the period under review. The CPW related to the Muskrat Falls generating facility is $3,525.9 million. A nominal amount of power with a CPW value of $69.9 million is also purchased from Labrador.

Power is also purchased from non-utility generators. The Cumulative Present Worth of the power purchased from these sources under this option is $682.6 million. Similar to the Isolated Island option, the Interconnected Island option also receives power from a variety of smaller units, except that the Interconnected Island option has only 21 such units in comparison to the Isolated Island option which has approximately 45 company owned facilities.

The combined CPW for the Interconnected Island option Power Purchases is $6,467.1 million.

4.7 Sensitivity Analysis

The Base Case for each of the two options is as noted below in Table 13. A number of alternative cases were prepared in order to bring more perspective to the Base Case. The sensitivities prepared by Nalcor include fuel price, capex, interest rates, and carbon credits.

Table 13: CPW Sensitivity Analysis

	CPW (millions)	Interconnected Island option	Isolated Island option	Difference
1	Base Case	8,366	10,778	2,412
2	PIRA Fuel Price – Expected	8,376	11,391	3,015
3	PIRA Fuel Price – Low	8,000	8,584	584
4	PIRA Fuel Price – High	8,836	15,435	6,598
5	Increase Capex 10%	8,882	11,034	2,152
6	Increase Capex 25%	9,654	11,417	1,763
7	Decrease Capex 10%	7,837	10,523	2,686
8	Increase Interest Rate 50 bps	8,604	10,863	2,259
9	Increase Interest Rate 100 bps	8,851	10,947	2,096
10	Decrease Interest Rate 25 bps	8,250	10,736	2,486
11	Carbon Pricing commencing 2020	8,368	11,360	2,992

PIRA Fuel Price Forecast

The Base Case CPW for each of the options is based on the PIRA "Reference Price" which is the price for delivery at a specific location, based on a current 'reference' scenario for various world financial and economic drivers. The PIRA "Expected Price" is the weighted average price forecast of the reference price, high price and low price forecasts. The probabilities assigned to each of the reference price, the high price and the low price have discrete probabilities which can individually vary across various forecasts.

Table 14 below illustrates the impact of experiencing a High Fuel Price Forecast is asymmetrical to that of a Low Fuel Price Forecast. A Low PIRA Fuel Price forecast reduces the CPW 'Preference for the Interconnected Island option' by $1,828 million whereas a High PIRA Fuel Price forecast increases the CPW 'Preference for the Interconnected Island option' by $4,186 million. The consequential negative impact on the CPW associated with an increase in the fuel price forecast is much more substantial than the benefit associated with a decrease in the fuel price forecast.

Table 14: Fuel Price Asymmetry (Scenarios 2, 3, 4 and 11)

CPW (millions)	Preference for Interconnected Island option	Variance from Preference for Interconnected Island option
PIRA Fuel Forecast – Reference Price	2,412	---
PIRA Fuel Forecast – Expected Price	3,015	Increase by 603
PIRA Fuel Forecast – Low Price	584	Decrease by 1,828
PIRA Fuel Forecast – High Price	6,598	Increase by 4,186
Carbon Pricing commencing 2020	2,992	Increase by 580

The carbon pricing sensitivity is included here in the Fuel Price analysis which indicates a $580 million preference for the Interconnected Island option. The purpose for including this here is that the Federal Government recently introduced final regulations on coal burning electrical plants September 5, 2012 and it is anticipated that all thermal power plants will come under regulation in the future.

Capital Cost Projections for Muskrat Falls and Labrador Island Link

Scenarios numbered 5, 6 and 7 reflect variances of capital costs in the order of magnitude of plus 10%, plus 25% and minus 10%. According to an Estimate Accuracy Analysis Report provided by Nalcor to MHI, the engineering and detailed design of the Lower Churchill Project was approximately 40% complete in April 2012. Given a project level of definition of approximately 40%, the project falls within the range of a Class 2 to Class 3 level according to the AACE Classification System. A mid-range amount of 25% level was applied for purposes of setting an appropriate level for the sensitivity capex variance in the CPW analysis.

The sensitivity level of +10% applied to the level of capex falls within the outer limit of the 25% sensitivity and has been included as a directional indicator. The sensitivity level of minus 10% is also a directional indicator. The minus 10% used for the sensitivity analysis increases the CPW preference for the Interconnected Island option to $2.686 billion.

Table 15 below summarizes the impact of comparing three scenarios against the CPW Base Case.

Table 15: Impact of Capex (Scenarios 5, 6 and 7)

CPW (millions)	Preference for Interconnected Island option	Variance from Preference for Interconnected Island option
Base Case CPW	2,412	---
Increase Capex 10%	2,152	Decrease by 260
Increase Capex 25%	1,763	Decrease by 649
Decrease Capex 10%	2,686	Increase by 274

An increase in capital costs of 10% for both Muskrat Falls and the Labrador Island Link, results in a CPW Preference for the Interconnected Island option of $2,152 million, being a decrease of $260 million relative to the Base Case. An increase of 25% in capital costs results in the Preference for Interconnected Island option being reduced to $1,763 million, which is a decrease of $649 million relative to the Base Case. In contrast, should the capital costs related to the construction of Muskrat Falls and the Labrador Island Link decrease by 10%, the Preference for the Interconnected Island option will be increased to $2,686 million, which is an increase of $274 million relative to the Base Case.

Interest Rates

Table 16: Impact of Interest Rates (Scenarios 8, 9, and 10)

CPW (millions)	CPW Preference for Interconnected Island option	Variance from Preference for Interconnected Island option
Base Case CPW	2,412	-
Increase Interest Rate 50 bps	2,259	Decrease by 153
Increase Interest Rate 100 bps	2,096	Decrease by 316
Decrease Interest Rate 25 bps	2,486	Increase by 74

Recognizing the capital expenditures required for the Interconnected Island option are more substantial than for the Isolated Island option, an increase in the interest rates has a greater impact on the CPW results for the Interconnected Island option. An increase of 50 basis points (bps) being one-half of a percent in the interest rate will decrease the CPW preference for the Interconnected Island option by $153 million. A full percent increase in the interest rates will decrease the CPW preference for the Interconnected Island option by $316 million. In contrast, a 25 basis point decrease in the interest rates will enhance the CPW preference for the Interconnected Island option by $74 million.

Load Forecast

Making a finite determination of the load forecast into the future incorporates many variables. The matter is particularly exacerbated by the fact that the numbers of industrial customers are few and therefore, the opportunity for load diversity is limited. The forecast period for this review is 50 years. It is acknowledged there is a possibility that in the short term, the industrial load may decline; however, when put into a long term perspective, it is not unreasonable to expect some opportunity for growth in the industrial sector. Nalcor did not include any growth of industrial load over the long term. From this broader perspective, there appears to be a reasonable offset between the short and long term load forecast projections. In addition, it is noted in section 2.1.4 that the extrapolated energy forecast is only 44% of the load expected over the next 20 years. To the extent Nalcor has not already committed to sell all of the energy output from the Muskrat Falls and Labrador Island HVdc Link facility, the Interconnected Island option is better positioned to address any future additional load increments than with the Isolated Island option. In contrast, should the Isolated Island option be faced with increased future load growth beyond that identified in the 2012 Load Forecast, it would not be unreasonable to expect that it would trigger the need for more combustion turbines and greater fuel consumption.

It is also noted in the CPW analysis prepared by Nalcor that the volumes of energy consumed are greater for the Interconnected Island option relative to the Isolated Island option. The additional volumes are tied to the elasticity factor associated with the lower sales price for customers supplied by the Interconnected Island option. Although the lower unit sales prices benefit the customers, the greater sales volumes attract more absolute costs to the Interconnected Island option. If the impact of the elasticity factor was normalized in the Interconnected Island option, this would enhance the differential between the two options in favour of the Interconnected Island option.

4.8 Conclusions Relating to CPW

1. The results of the CPW review indicate a strong preference in favour of the Interconnected Island option over the Isolated Island option. The Base Case indicates a Cumulative Present Worth preference of $2.412 billion related to the period under review. ***Based on the inputs provided by Nalcor, determination of the CPW base case results and the related sensitivity analysis presented by Nalcor are considered reasonable.***

2. When the CPW results were stress tested for increases in projected capital costs (Capex +25%) for the Interconnected Island option which has a relatively high level of capital investment relative to the Isolated Island option, the CPW preference continued to be in excess of $1.763 billion in favour of the Interconnected Island option. Recognizing the project has moved to a Decision Gate 3 level of review, and acknowledging the amount of contingency included in the Capital Costs estimates for the Interconnected Island option, there is an equal probability the capital costs will decrease as well as increase. A decrease of 10% to the capital costs for the Interconnected Island option will expand the CPW preference to $2.686 billion in favour of the Interconnected Island option.

3. When the CPW results for the Isolated Island option were stress tested for decreases in the projected fuel costs based on the externally provided PIRA Low Fuel Price Forecast, the CPW preference continued to be in excess of $584 million in favour of the Interconnected Island option. Even though the project has moved to a Decision Gate 3 level of review, it is not possible to provide any degree of certainty around fuel costs projected into the future. The stress test of using the High PIRA fuel forecast results in a CPW preference of $6.6 billion in favour of the Interconnected Island option. Within the context of the PIRA forecast parameters, the CPW risk associated with a high fuel price forecast is substantially greater than the benefit associated with the low fuel price forecast.

4. Assuming the energy output from the Interconnected Island option is not fully committed; the Interconnected Island option is better positioned to accommodate future load growth beyond that included in the CPW base case for each of the two options.

5. Any moderate shift (1%) in interest rates will not materially impact the CPW differential between the two options.

5 Conclusions and Recommendations

MHI completed its analysis of both the Muskrat Falls and Labrador-Island HVdc Link, identified as the Interconnected Island option, and the development of various power units on the Island, identified as the Isolated Island option. MHI has found Nalcor's work to be skilled, well-founded, and in accordance with industry practices. Both options have increased substantially in cost from prior estimates released in November 2010. However, the Interconnected Island option continues to have a lower present value cost given the full range of sensitivity analysis and inputs provided by Nalcor to MHI.

Interconnected Island Option

The Interconnected Island option retained the same component mix, namely a 900 MW Labrador Island HVdc link, seven 50 MW CT's and one 170 MW CCCT. There was some realignment of the generating station at Muskrat Falls as a result of detailed design modeling.

The Load Forecast for the Interconnected Island option showed an increase in domestic load for the period to 2029 which was expected due to higher economic forecasts for personal disposable income and population. However the general service sectors show a decrease which would appear to be conservative as it normally mirrors domestic load. The industrial load does not include any new accounts over the entire time span which is very likely conservative. MHI finds that the Interconnected Island Forecast is well founded and appropriate as an input into the Decision Gate 3 process.

AC Integration Studies

The review of the ac integration studies related to the Interconnected Island option indicate that Nalcor is in compliance with good utility practices and that there is an opportunity, during detailed design to optimize final configurations that may enhance system reliability.

HVdc Converter Stations

An assessment of the technical work completed by Nalcor and its' consultants on the HVdc converter stations, electrode lines, and associated station equipment showed the work was reasonable as an input to the Decision Gate 3 process. MHI did recommend some improvements to the project to Nalcor which could be made during the detailed design phase with little impact to the CPW result.

HVdc Transmission Line, Electrode and Collector System

The cost estimates, construction schedules, and design methodologies undertaken by Nalcor and its consultants were reviewed. In MHI's opinion, Nalcor has undertaken a diligent and appropriate approach to design the transmission line to withstand the many unique and severe climatic loading regions along its line length. Costs have increased significantly as a result of the need to satisfy reliability requirements as part of the engineering undertaken to date. MHI continues to support selecting a 1:150 year climatic return period due to the criticality of the HVdc transmission line to the Newfoundland/Labrador electrical system.

Strait of Belle Isle Crossing

A review of the work completed by Nalcor and its consultants has shown that little has changed the design definition and concept in configuration of the marine crossing. Further bathymetric work and a test borehole have shown that costs have increased marginally. MHI considers the marine crossing viable, within the AACE Class 3 estimate range, and can be completed as planned within the allotted time frame.

Muskrat Falls Generating Station

The cost estimates, construction schedules, and design work undertaken by Nalcor and its consultants were reviewed as part of the Decision Gate 3 process. The proposed schedule is appropriate and consistent with best utility practices. Based on the amount of engineering completed and the number of tenders for which estimates have been provided by potential suppliers, MHI considers the Decision Gate 3 cost estimate to be an AACE Class 3 estimate and thus would be considered reasonable for a Decision Gate 3 project sanction. The Labrador transmission assets have also been appropriately designed, scheduled, with a cost estimate consistent with good utility practice.

Isolated Island Option

The Isolated Island option, for Decision Gate 3, is comprised of the following generation resource mix of seven 170 MW CCCTs (net one new), fourteen 50 MW CTs (net 9 new), 77 MW of small hydroelectric plants, and 279 MW (net 225 MW new) of wind farms.

The load forecast for the Isolated Island option is somewhat less than the Interconnected Island option due to the higher marginal price of electricity. However, the general service sectors show a decrease, which would appear to be conservative as it normally mirrors domestic load. MHI finds that the Load Forecast for the Isolated Island is well founded and appropriate as an input into the Decision Gate 3 process.

Holyrood Thermal Generating Station

As part of the Isolated Island option, the Holyrood Thermal Generating Station is assumed to remain in full operation until 2035 with upgrades taking place as previously committed. Pollution control equipment was also scheduled to be installed by 2018. Vendors were canvassed for actual costs of equipment and fuel oil prices were updated to reflect 2012 PIRA estimates.

The Holyrood Thermal Generating Station was scheduled for replacement in 2035 but is now to be decommissioned. Estimates have been updated to reflect this change in operation.

Wind Farms

Wind farms are not deployed in the Interconnected Island option. In the Isolated Island option, a significant amount of wind power has been added, replacing a portion of the generation supplied by thermal generation operating on base load, as recommended in the external 2012 Hatch study.

MHI has been studying the proposed wind plan for inclusion into the Isolated Island option, as a separate project. The report of this study will be published under separate cover "Decision Gate 3 Review of the Wind Study for the Isolated Island of Newfoundland". The new generation resource plan allows for up to 279 MW in total wind capacity on the Island as part of the Isolated Island option.

MHI has reviewed the costs associated with the fixed charges and operating expenses of the wind farms used in the Isolated Island option and find them reasonable as inputs into the CPW base case analysis.

Simple and Combined Cycle Combustion Turbines

In the Interconnected Island option, ten 50 MW peaking units are required to match the increase in expected load along with one 170 MW combined cycle unit. For Decision Gate 3, costs for the CCCT were upgraded for the analysis with input from consultants and vendors.

The Isolated Island option is comprised of fourteen 50 MW CT peaking units with seven base load 170 MW CCCT units, plus 225 MW of wind capacity. While there was no change in the types of units specified, there was an upgrade of costs to reflect current market prices.

Small Hydro Power

There were no changes in the configuration of any of the three small hydropower generating stations to be developed for the Isolated Island option from the previous generation master plan (November 2010). Island Pond GS and Portland Creek GS were updated to current costs whereas additional work was undertaken on Round Pond GS to update a 23 year old study. The costs presented for all three plants are reasonable as an AACE Class 4 estimate suitable as input for the alternative option in the Decision Gate 3 analyses.

CPW

Both the Interconnected Island and Isolated Island options have been updated to reflect current market conditions and cost inputs for the Decision Gate 3 analysis. This work included a re-evaluation of fixed charges, operating costs, fuel costs and power purchase costs and cost estimates were reviewed by MHI. The result of the CPW analysis indicates a preference for the Interconnected Island option of $2.4 billion over the Isolated Island option. Costs of both options have increased proportionately as a result of escalation and scope change. With the assumptions and inputs provided by Nalcor to MHI, the Interconnected Island option remains the least cost option to meet the needs for capacity and energy to supply the forecasted load in Newfoundland and Labrador until 2067.

It is important to note that any monetization of excess power from Muskrat Falls to external markets was not factored into MHI's Decision Gate 3 analysis; the monetization is expected to improve the overall business case of the Interconnected Island option. Also, any uncommitted energy from Muskrat Falls would allow Nalcor to more easily address any large future load additions to the Island of Newfoundland or Labrador.

There remains significant uncertainty in fuel price forecasts which are magnified over the 50 plus years of the study horizon. The Interconnected Island option has much less exposure to variance in fuel price.

MHI Recommends

Given the analysis that MHI has conducted based on the data and reports provided by Nalcor, MHI recommends that Nalcor pursue the Interconnected Island option as the least cost alternative to meet future generation requirements to meet the expected electrical load in Newfoundland and Labrador.

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APPENDIX E

Synchronous Condenser Requirement

2014 Newfoundland and Labrador Hydro Planning Process Review

March 21, 2014

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Liability Note

Contents

Executive Summary

Over the weekend of January 3rd, 2014, Newfoundland and Labrador Hydro ("NLH") experienced a series of largely unrelated events that led to four days of rolling blackouts. On January 17th, The Board of Commissioners of Public Utilities ("the Board") initiated a process to gather information from NLH and Newfoundland Power ("NP") with a focus on whether load requirements on the Island Interconnected system can be met in the near term. Specific issues to be addressed include: asset readiness, maintenance practices, load forecasting, planning criteria and assumptions, equipment performance and reliability, emergency preparedness, system response, and restoration efforts.

NLH retained the services of Ventyx, Inc. to provide a review of both the generation planning processes that form the basis of NLH's strategic plans and forecasts, and NLH's long term (20 year) and medium-term (5 year) load forecasting. Ventyx has not found any evidence that either the generation planning process or the load forecasting process have contributed to the events of January.

In the near term, NLH's current resource expansion plan is within the reliability criteria in all calendar years except 2015.

	Loss of Load Hours (Hours)	Reserve Margin (Percent)
2013	0.97	16.32
2014	2.59	12.28
2015	3.98	10.32
2016	2.73	12.21
2017	2.68	11.00

The previous table is based on the assumption that a new 50 MW CT, is in service December of 2015. If that unit does not achieve that commission date or an equivalent resource is not implemented the LOLH would increase to 4.57 in 2015 and 6.02 in 2016.

NLH is currently considering six options[1] for meeting the expected LOLH in 2015. Each of these options offers the possibility to reduce the system LOLH.

1. Retain the 16 MW (10 MW to the system) diesel facility at Holyrood;
2. Review what is needed to make the remaining 4.6 MW of diesel power at Holyrood available to the system by plant modifications to increase equipment ratings to deliver 14.6 MW capacity;
3. Enter into interruptible contracts with large Industrial customers;
4. Seek already built combustion turbines in the 50 to 100 MW range to supply deficit and blackstart;
5. Initiate the supply of a new 60 MW (nominal) combustion turbine for the Holyrood site to supply deficit and blackstart; and
6. Continue and possibly enhance conservation and demand management initiatives, with the focus on demand management.

The new 50 MW (nominal) combustion turbine or other combustion turbine options are key resources for NLH's near term reliability of supply. The current plan has this unit commissioned in December of 2015. Without this unit, NLH would face LOLH reliability indices of 4.57 hours/year in 2015, 6.02 hours/year in 2016, and 5.71 hours/year in 2017, the Labrador Infeed is in service in December of 2017.

Statistically, demand reduction is a slightly better alternative to generation additions due to inherent uncertainty of generation forced outages. In order to reduce the expected 2015 LOLH of 3.98 hours/year to 2.80 hours/year, in addition to the nominal combustion turbine assumed, NLH would need to secure approximately 40 MW of either interruptible contracts with existing

[1] Newfoundland and Labrador Hydro, *PUB-NLH-062* (Newfoundland and Labrador Hydro: Board Response, February 2014)

customers or conservation and demand management initiatives. If that is not practical, then the difference can be made up from the remaining generation capacity options.

Furthermore, NLH uses reasonable estimates for generation forced outage assumptions as compared to Canadian Electricity Association (CEA) five year averages and the five year averages for its own equipment. The assumptions in Strategist are based upon data collected between 2000 and 2004. The generation forced outage assumption for Holyrood and Bay D'Espoir are 9.64%[2] and 0.91%[3], respectively, and they contributed to the forecast 2015 LOLH of 3.98 hours/year. Recent data from NLH operating data, from 2008 to 2012, indicates that the historical performance for Bay D'Espoir has improved to 0.41% and worsened for Holyrood to 10.69%. These figures are relatively consistent with current performance, however if the generation forced outage assumptions were improved for Bay D'Espoir, the 2015 LOLH would drop to 3.69 hours/year. If the generation forced outage assumptions were changed for Holyrood the contribution to the 2015 LOLH would increase to 4.49 hours/year.

The primary drivers are the Holyrood units. Focusing only on Holyrood, if the Holyrood units could achieve an annual forced outage rate of 8.48% or less then the system would achieve a LOLH of 2.8 hours/year. Recognizing the age of these assets, this may not be practical in the short term and continuing the current assumptions is prudent planning, particular for the near term. As well, there is merit in assessing some variation of this expected performance to gauge sensitivity on the LOLH result.

The current projected plan is based upon a normalized weather forecast. Weather normalization is an industry standard process that adjusts actual peak outcomes to what would have happened under normal weather conditions. Beyond the next seven days weather forecasting is complex and not always accurate. Therefore, NLH should look at a severe

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[2] Source: CEA Typical 2000-2004. Table 6.2.2 100-199 MW Classification for Holyrood.

[3] Source: NLH Operating Experience between 2000-2004. Weighted Average based on Bay D'Espoir units & Hinds Lake, Upper Salmon, Cat Arm and Paradise River

weather sensitivity to gauge how the system might respond to greater than expected demand particularly in making near term investment decisions.

Specific process recommendations:

- Load Forecasting
    - Continued surveying of the customer base in terms of both average energy use and saturations of heating.
    - Develop alternative load forecasts in both the scenario development and the sensitivity analysis phases.
- Generation Planning
    - NLH should continue forward with its generation planning reserve criterion.
    - After NLH's interconnections are established in 2017, NLH should revisit both their generation planning reserve criterion and their modeling of external markets.
    - NLH should continue forward with its practice of maintaining a more conservative estimate of EFOR for the units.
    - Compute a break-even EFOR for each class of its generation to determine the point at which a generator's EFOR will result in the system exceeding the LOLH criteria of 2.8 hours/year
- Develop a formal risk analysis process that utilizes scenarios and sensitivities to test the robustness of resource plans.

Study Objective

Over the weekend of January 3rd, 2014, NLH experienced a series of events that led to four days of rolling blackouts. On January 17th, The Board initiated a process to gather information from NLH and NP with a focus on whether load requirement on the Island Interconnected system can be met in the near term. Specific issues to be addressed include: asset readiness, maintenance practices, load forecasting, planning criteria and assumptions, equipment performance and reliability, emergency preparedness, system response, and restoration efforts.

NLH retained the services of Ventyx, Inc. to provide a review of both the generation planning processes that form the basis of NLH's strategic plans and forecast and NLH's long term (20 year) and medium term load (5 year) forecasting. Specifically, Ventyx was asked to review:

- The overall planning process and assumptions used by NLH in developing their current long range and strategic forward looking plans;
- Provide commentary on the existing planning processes and criteria and make recommendations as to specific improvements as required;
- Review of the process and assumptions used by NLH in developing their current long range load forecast and shorter term operational forecasts;
- Provide commentary on the load forecasting processes, criteria and assumptions and make recommendations as to specific improvements as required;
- Review of the Strategist model assumptions used by NLH in developing their current long range and strategic forward looking plans; and
- Provide commentary on the existing planning processes and criteria and make recommendations as to specific improvements as required.

VENTYX

Ventyx brings a dedicated team of expert consultants that combines experience, industry knowledge, market knowledge, and software expertise to support consulting engagements. Ventyx provides professional consulting services to energy companies in the areas of integrated resource planning, market price forecasting, resource evaluation and planning, trading and settlement, and electric transmission economic analysis. Ventyx has worked with NLH both in support of Ventyx's Strategist software and .with analytical modeling to evaluate the economic and system impacts of the Muskrat Falls hydro project as well as the Maritime Link project with Nova Scotia. Ventyx conducted multiple analytical modeling studies of this pair of projects over a three year period that also included analytical modeling covering the provinces of New Brunswick, Prince Edward Island, Nova Scotia and Newfoundland Labrador as well as surrounding market areas in Quebec, New York and New England for the Atlantic Energy Gateway project

Strategist®

Strategist is a computer software system, developed by Ventyx, LLC, which supports electric utility decision analysis and corporate strategic planning. Strategist is available as a demand-side management analysis system, as a least cost resource optimization system, as a comprehensive planning tool for quick evaluation of hundreds of alternatives, as a finance and rates planning system and as selected application modules that complement planning capabilities already in place. Strategist's advantage as an integrated planning system is its strength in all functional areas of utility planning. Strategist allows analysts to address all aspects of an integrated planning study at the depth and accuracy level required for informed decisions. Hourly chronological load patterns are recognized. Production cost simulations are comprehensive, yet fast. The production costing procedure consists of two stages. In the first stage, the operation of hydro generation and sale and purchase transactions are simulated. The pumped storage facilities, economic energy interchange, and direct load control programs are then economically dispatched based on the marginal cost curve of the system. The result of this first stage is the remaining annual or seasonal thermal load duration curve. In the second stage, the expected operation of the thermal generating units within the year is simulated by a probabilistic technique. The results are the production costs and system reliability indices. The PROVIEW (PRV) Module is a resource planning model which determines the least-cost balanced demand and supply plan for a utility system under prescribed sets of constraints and assumptions. PROVIEW incorporates a wide variety of expansion planning parameters including alternative technologies, unit conversions, cogenerators, unit capacity sizes, load management, marketing and conservation programs, fuel costs, reliability limits, emissions trading and environmental compliance options in order to develop a coordinated integrated plan which would be best suited for the utility. The PROVIEW module works in concert with the GAF Module to simulate the operation of a utility system. PROVIEW's optimization logic then determines the cost and reliability effects of adding resources to the system, or modifying the load through demand-side management (DSM) or marketing programs.

Incident Description

Over the weekend of January 3rd, 2014, NLH experienced a series of events that led to four days of rolling blackouts.

Issues within Scope

The Board initiated a process to gather information from NLH and NP with a focus on whether load requirement on the Island Interconnected system can be met in the near term. Specific issues to be addressed include: asset readiness, maintenance practices, load forecasting, planning criteria and assumptions, equipment performance and reliability, emergency preparedness, system response, and restoration efforts. The scope of this report is focused on the load forecasting and planning criteria and assumptions. With the NLH system setting record peaks during this unfortunate event, the question of load forecast accuracy is raised. The primary planning criteria that are related to an event of this nature are planning reserves and generation forced outage rates. Finally, the issue of load forecasting and planning criteria is enveloped in the overall process of sensitivity analysis to address the inherent risk of the NLH portfolio.

Load Forecasting

Load Forecasting is the process of estimating the demand that customers will place on the system. The process for load forecasting is, generally, defined by the time horizon of a specific forecast. Short term forecasts are hourly in nature and cover the time horizon from next hour to seven days to support short term unit commitment and scheduling. Short term forecasts are focused on the most recent historical relationship of weather to load aligned with short term forecasts of weather conditions. As the load forecasting process passes from the short term to longer term, the reliability of forecasted weather drops dramatically. Longer term forecasts are typically represented as annual peaks and energies, with monthly detail, to support budgeting planning. Longer term forecasts rely on the historical relationships of weather to load along with seasonal patterns and economic drivers.

Generation Planning Criteria

The generation planning criteria for planning reserves and generation forced outage rates combine to form a prediction of the expected LOLH reliability index. This reliability index forms the foundation of a minimum reliability threshold of 2.8 hours/year. For each year of the NLH planning horizon, the system is designed to maintain sufficient generation planning reserves to ensure the minimum reliability threshold is met. Generation planning reserves are the MW difference between available capacity and normalized peak demand that are available to meet unforeseen increases in demand, such as extreme load, and unexpected outages of existing capacity. Forecasted trends in LOLH identify whether generation capacity additions are keeping pace with load growth.

Scenario/Sensitivity Planning

Scenario planning is a strategic planning methodology used to identify and assess the inherent risks and benefits of a flexible long term plan. Scenario planning recognizes that many factors may combine in complex ways to create sometimes surprising futures. Scenario planning seeks to identify the causal relationship between factors and demonstrate a plans flexibility to adapt. Scenario planning develops an internally consistent story about the conditions in which the system might be operating in the future that differs from baseline assumptions in sometimes significant ways and usually involves alterations to all of the assumptions at one time. Sensitivity planning varies each of the assumptions either one at a time or in correlated groups to determine how sensitive the results are to changes in the assumptions. These planning techniques are important when there are variables such as weather that can potentially impact the reliability of the system.

Load Forecasting

Background

Load Forecasting is the process of estimating the demand that customers will place on the system. The process for load forecasting is, generally, defined by the time horizon of a specific forecast. Short term forecasts are hourly in nature and cover the time horizon from next hour to seven days to support short term unit commitment and scheduling. Short term forecasts are focused on the most recent historical relationship of weather to load aligned with short term forecasts of weather conditions. The short term forecasts prepared by NLH use a neural network forecasting approach using the Nostradamus modelling software.

A medium term forecast that covers a time horizon of five years is used for budgeting and near-term supply adequacy. The medium term forecasts are a combination of the NP forecast for their service territory and NLH economic and regression processes for their rural customers and customer input for the industrial loads.

Longer term forecasts cover the time horizons of 20 years and are typically represented as annual peaks and energies, with monthly detail, to support long term generation planning. The long term forecast is performed by NLH using economic and regression techniques to forecast NP, NLH rural loads, and Industrial customer forecasts of their loads. The long term forecasts rely on the historical relationships of weather to load along with seasonal patterns and economic drivers.

The review of the load forecasting process included a review of the original filings with the Board concerning the Muskrat Falls Project, review of two independent, detailed reviews of the project, a review of the responses to the Board of questions concerning the incidents this winter, and one-on-one interviews with both NLH and NP forecasting staff. Since the independent review of the load forecast conducted by Manitoba Hydro International ("MHI") was a detailed review of the assumptions, the review described in this report focused on the methodology and a look at the validity and accuracy of the forecast. Personal interviews were held with the staffs of NLH and NP to ascertain the sequencing and procedures of each company and the interfacing and integration of the individual component forecasts into a single product. Of particular interest was the accuracy of the winter peak as it applies to the incidents described above.

- The interviews with the NP load forecasting staff revealed the medium term forecast of NP service territory energy was performed for Domestic, General Services and Area and street light classes. Although the process was different for each class, the basic process is an average use methodology that applied econometric forecasting techniques to determine average use per consumer that was then applied to a customer growth forecast.
- The medium term peak demand for NP was developed using an average load factor methodology that calculates a 15 year average load factor that is then applied to the medium term energy forecast to determine the NP service territory Winter Peak demand. This is a standard utility practice.
- The NLH long term load forecasting process is a combination of econometric and regression analyses to determine the energy and peak demand for NP and the NLH rural

groups with industrial energy and demand requirements conditioned by individual customer input .

- The long term peak for NP is forecast by NLH using regression analyses that link NP peak demand to weather, domestic electric heat customer growth, general service sales growth and other economic factors. The peak for the NLH rural group is calculated using a long term historical load factor method that is applied to the forecasted energy. The industrial peak is developed through direct input of existing industrial customers. No forecast is made of potential new industries unless it is fairly certain that a change is going to be made either through government action or a committed industrial customer.

NLH uses historical hourly shapes to develop typical 168 hourly week shapes for each month of the year. These typical shapes are applied to each year of the study and are adjusted by the Strategist Load Forecast Adjustment ("LFA") module to meet the data entered for peak and energy from the forecast. NLH has not updated the historical data since 2002 and is scheduled to perform the update in the next 12 months as part of the next generation expansion planning exercise. Since the system has had a fairly stable load factor and since the LFA continuously modifies the shape to meet the forecast this should not impact the results of the studies. This would only be a problem if NLH was evaluating new Conservation and Demand Management ("CDM") or time dependent programs such as time-of-day rates.

NLH has elected to set the study period to 50 years so that it would cover the financing period of the Muskrat Falls project. This is typically performed using either Economic Carrying Charge calculations or infinite end-effects with a shorter study period of twenty years. However, after discussion with NLH planning staff Ventyx determined that the manner in which they performed the extension of the load forecast and other model data was consistent with the Strategist end-effects methodology.

Conclusions

The methodology used by both NP and NLH are consistent with accepted utility practices. It has been noted by another independent review, by MHI, that the process could be improved by changing to an end-use forecast. It is Ventyx's opinion, based on experience, the complexity and time to generate an end-use forecast would not significantly improve the demand forecast in the mid-term. This is also true since the existing methodology aligns with survey results of the major end-use on the system which is electric space heating.

The econometric methods being used by NLH are prudent and well validated. The regression equations all have statistical coefficients of determination (R^2) that are in the very high range. The R^2 can be interpreted as the percent of variation in the predicted value that is explained by the given variables. Table 1 enumerates the R^2 for each of the equations. The closer an R^2 value is to 100% the better the fit of the equation to the data provided. The R^2 for the regression equations that directly impact the forecast of system peak demand in the long term are included below.

Equation	**R^2**
NP Domestic Class	
Customer Additions	93.4%
Penetration of Elect. Heating	88.5%
Conversion of Non-Elect Heat	78.9%
NP General Service Class	
Electric Heat Customer Load	99.9%
NLH Rural Domestic Class	
Average Use	98.1%
NLH Rural General Service Class	
Energy	99.6%
NP Peak	99.7%

Table 1 Coefficients of Determination[4]

No attempt was made in this review to verify or validate the actual data used since a previous report was issued by MHI showing a detailed discussion of the data. It is obvious weather has a significant impact on the resulting energy and peak demand forecasts. NLH's forecasting models include weather variables to account for the impacts due to changing weather conditions through the historical period. However, what is missing is an evaluation of the energy and demand impacts due to extreme weather conditions. These extremes should be evaluated using sensitivities and scenario planning techniques.

Figure 1, shows a comparison of the forecasted winter months peaks to the actual peaks for the system for the years 2004 to December 2013. Since 2004 the actual winter peaks have consistently been below the forecasted peaks with the exception of seven months out of forty winter months that the actual has been higher than the forecast. However, since those seven times do not occur in the same month it would suggest that there was some random pattern

[4] Manitoba Hydro International, *MHI-Report-Volume II-Load Forecast* (February 2012)

such as weather that is impacting the actual. A review of the deviations shows that it is largely weather that impacts all the discrepancies As indicated by the red bars, the actuals are consistently less than the forecast because NLH has experienced a period of warmer than normal peak weather conditions over this period. The December 2013 discrepancy was impacted additionally by the “exceptional” loads resulting from unavailable Avalon generation that resulted in higher system demand loads than expected. If a variable such as the number of customers was off it would be impacting the forecast for all winter months in that period.

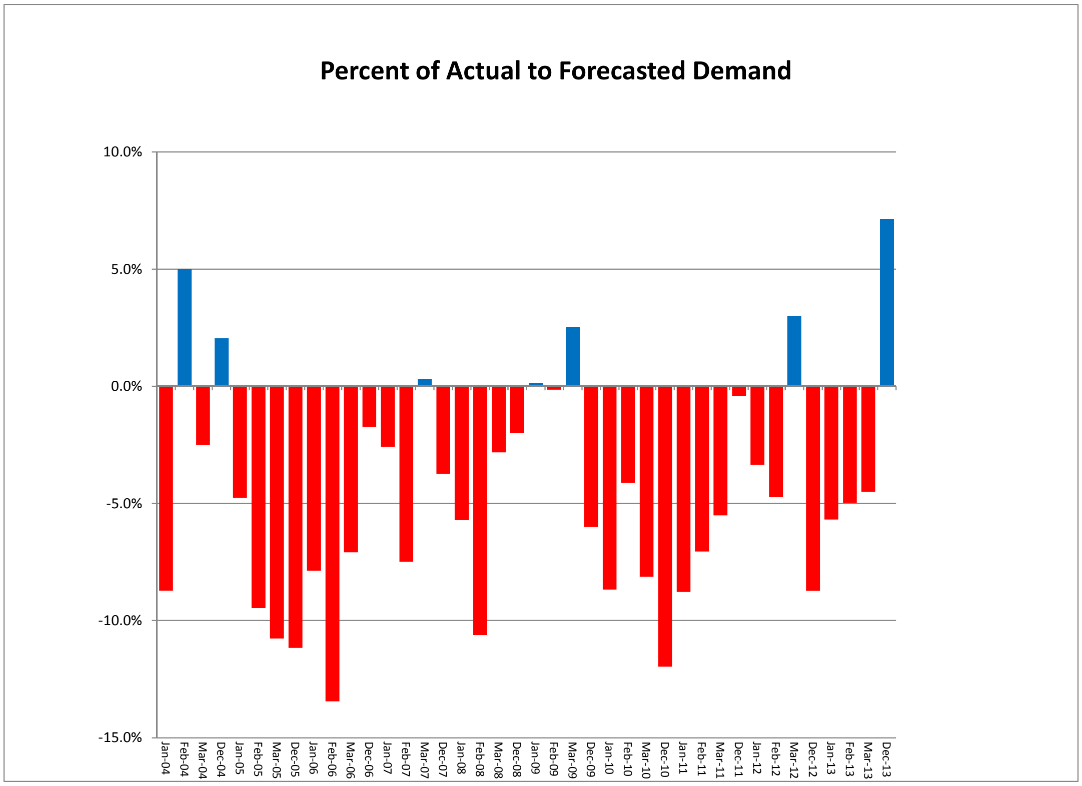

Figure 1[5]

Recommendations

It was noted above that Ventyx does not believe it is desirable to change the forecast methodology to an end-use model. Primarily this is due to the increased complexity and cost, but it is also noted above that the major end-use on the system is electric heat and is already included in the forecast model and thus capturing the majority of any additional detail accuracy

[5] Newfoundland and Labrador Hydro, *PUB-NLH-011* (Newfoundland and Labrador Hydro: Board Response, February 2014)

benefits that would be expected from an end use model. Since the R^2 for the two regression equations involving heating penetrations were 79% and 89% it would be advisable that NLH continue to refine their models with respect to these two variables. This can be further enhanced through continued surveying of the customer base in terms of both average use and saturation of this end use.

The above discussion has been in terms of the base-case scenario. Later in the report, Ventyx will discuss using a formal risk assessment process that includes the evaluation of plans under extreme weather conditions. As such, it will be important to develop alternative load forecasts in both the scenario development and the sensitivity analysis phases.

Generation Planning Reserve Criterion

Background

The purpose of a Generation Planning Reserve Criterion is to establish the minimum reliability threshold for a power system. The reliability of a power system is defined as the probability of providing customers with continuous service of a satisfactory nature. Reliability is one of the primary factors that drive the planning, design, operation, and maintenance of a power system. The most common index for reliability is the Loss of Load Probability ("LOLP") which is "the probability of the system load exceeding the available generating capacity under the assumption that the peak load of each day lasts all day."[6] Through a series of analytical processes the reliability index, LOLP, is translated to a reserve criterion stated in terms of Loss of Load Hours ("LOLH") or a defined reserve margin percentage. In Strategist, Loss of Load Hours is the expected total number of hours a year during which the utility will not be able to serve all of its customers. The percent reserve margin is based on the reserve margin at the time of the annual peak and defined as the amount of installed reserves, in MW, divided by the

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[6] J. Endrenyi, *Reliability Modeling in Electric Power Systems* (Ontario Hydro: John Wiley & Sons, 1978), 4

system peak demand, in MW. This reserve criterion serves as an input to capacity expansion optimization to ensure that all plans selected for comparison meet or exceed the minimum reliability threshold for a power system.

NLH's capacity planning reserve criterion for capacity planning is "The Island Interconnected System should have sufficient generating capacity to satisfy a Loss of Load Hours ("LOLH") expectation target of not more than 2.8 hours per year."[7] The LOLH target is based upon a Loss of Load Probability of 1 day in five years or, more commonly denoted as, 0.2 days per year. In 1977, the NLH System Planning department determined that "The LOLP index to be adopted depends upon the availability of capital. System Planning feels that a .1 days/year is not realistic and would suggest .2 days/year as an optimum value to aim for".[8] The results of NLH's recent 2012 capital planning study, 2012 DCL–PLF IT1–A-0801-_R-105 FE-1 Strategist 4.4.1, are enumerated in Table 2.

	Loss of Load Hours (Hours)	Reserve Margin (Percent)
2013	0.97	16.32
2014	2.59	12.28
2015	3.98	10.32
2016	2.73	12.21
2017	2.68	11.00

Table 2 Expected Loss of Load Hours

[77] PUB-NLH-008

[8] System Planning Department, *Recommended Loss of Load Probability (LOLP) Index for Establishing Generation Reserve Additions* (Newfoundland Labrador Hydro: internal memo, May 16, 1977), 19

Previous table is based on the assumption that a new 50 MW CT, is in service December of 2015. If that unit does not achieve that commission date the LOLH would increase to 4.57 in 2015 and 6.02 in 2016.

NLH is currently considering six options[9] for meeting the expected LOLH in 2015. Each of these options offers the possibility to reduce the system LOLH.

1. Retain the 16 MW (10 MW to the system) diesel facility at Holyrood;
2. Review what is needed to make the remaining 4.6 MW of diesel power at Holyrood available to the system by plant modifications to increase equipment ratings to deliver 14.6 MW capacity;
3. Enter into interruptible contracts with large Industrial customers;
4. Seek already built combustion turbines in the 50 to 100 MW range to supply deficit and blackstart;
5. Initiate the supply of a new 60 MW (nominal) combustion turbine for the Holyrood site to supply deficit and blackstart; and
6. Continue and possibly enhance conservation and demand management initiatives, with the focus on demand management.

The new 60 MW (nominal) combustion turbine or other combustion turbine options are key resources for NLH's near term reliability of supply. The current plan has this unit commissioned in December of 2015. Without this unit, NLH would face LOLH reliability indices of 4.57 hours/year in 2015, 6.02 hours/year in 2016, and 5.71 hours/year in 2017, the Labrador Infeed is in service in December of 2017.

Statistically, demand reduction is a slightly better alternative to generation additions due to inherent uncertainty of generation forced outages. In order to reduce the expected 2015 LOLH of 3.98 hours/year to 2.80 hours/year, NLH would need to secure approximately 40 MW of either interruptible contracts with existing customers or conservation and demand

[9] Newfoundland and Labrador Hydro, *PUB-NLH-062* (Newfoundland and Labrador Hydro: Board Response, February 2014)

management initiatives. If that is not practical, then the difference can be made up from the remaining generation capacity options.

Furthermore, NLH uses reasonable estimates for generation forced outage assumptions as compared to Canadian Electricity Association (CEA) five year averages and the five year averages for its own equipment. The assumptions in Strategist are based upon data collected between 2000 and 2004. The generation forced outage assumption for Holyrood and Bay D'Espoir are 9.64%[10] and 0.91%[11], respectively, and they contributed to the forecast 2015 LOLH of 3.98 hours/year. Recent data from NLH operating data, from 2008 to 2012, indicates that the historical performance for Bay D'Espoir has improved to 0.41% and worsened for Holyrood to 10.69%. These figures are relatively consistent with current performance, however if the generation forced outage assumptions were improved for Bay D'Espoir, the 2015 LOLH would drop to 3.69 hours/year. If the generation forced outage assumptions were changed for Holyrood the contribution to the 2015 LOLH would increase to 4.49 hours/year.

The primary drivers are the Holyrood units. Focusing only on Holyrood, if the Holyrood units could achieve an annual forced outage rate of 8.48% or less then the system would achieve a LOLH of 2.8 hours/year. Recognizing the age of these assets this may not be practical in the short term and continuing the current assumptions is prudent planning, particular for the near term. As well there is merit in assessing some variation of this expected performance to gauge sensitivity on the LOLH result.

The standard industry practice is to apply a LOLP of 0.1 days/year, or "one day in ten years". However, it should be noted that the 0.1 days/year standard applies to ***interconnected*** utilities. For true "stand alone" utilities, the cost to achieve a 0.1 days/year standard is often cost prohibitive. In 1977, NLH conducted a thorough analysis of system reserves and concluded with the recommendation of 0.2 days/year, or "one day in five years". NLH justified the 0.2

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[10] Source: CEA Typical 2000-2004. Table 6.2.2 100-199 MW Classification for Holyrood.

[11] Source: NLH Operating Experience between 2000-2004. Weighted Average based on Bay D'Espoir units & Hinds Lake, Upper Salmon, Cat Arm and Paradise River

days/year over 0.1 days/year based on the economics of meeting the more stringent requirement. The incremental present value revenue requirements necessary to move from a reliability index of 1.0 days/year to 0.2 days/year was approximately $24 Billion[12]. The incremental present value revenue requirements necessary to move from a reliability index of 0.2 days/year to 0.1 days/year was approximately $17 Billion[13]. Simply stated, the cost to serve the last tenth of the reliability index was 71% of the cost to serve the total of the first eight tenths of the reliability index. NLH was justified in its decision to adopt a reliability index of 0.2 days/year.

From a generation mix perspective, the NLH system is "roughly" the same as it was in 1977; there is no reason to reassess its reliability standard of 0.2 days/year. The primary drivers that would prompt a utility to reassess its reliability standard include: resource mix, plant reliability and maintenance, and interconnections. In 1977, the NLH system was 63% hydro and 37% thermal. Today, the NLH system is 67% hydro and 33% thermal. In terms of plant reliability, the capacity weighted average effective forced outage rate in 1977 was 3.74% versus 4.05% today. From a system reliability standpoint, the NLH system is virtually equivalent to the system in 1977. However, NLH expects to complete the Maritime Link to Nova Scotia in 2017. When NLH interconnects with the North American grid, NLH should reassess its reliability standards in light of their access to new markets.

Loss of Load Probability is a characterization of the adequacy of the generation within a system to serve the load of the system. It is important to note that LOLP does not represent the reliability of the bulk transmission or distribution systems. For the purposes of NLH's planning criteria, it was necessary to translate the LOLP, which is a based on the peak load of each of the 365 days, to an hourly equivalent, LOLH. "When Hydro switched from SYPCO generation

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[12] Ibid, Table V. Grand Total (0.2) 2,896,178 (1977 K$) minus Grand Total (1) 2,872,516 (1977 K$) equals 23,662 (1977 K$).

[13] Ibid. Table V. Grand Total (0.2) 2,912,924 (1977 K$) minus Grand Total (1) 2,896,178 (1977 K$) equals 16,746 (1977 K$). 16,746 is 70.07% of 23,622.

planning software to PROSCREEN II [now called Strategist], it was necessary to switch to a Loss of Load Hours (LOLH) criterion. Benchmarking established that a LOLH of 2.8 hours per year was equivalent to a LOLP of 0.2 days per year, for Hydro's system."[14]

In 2017, the Maritime Link to Nova Scotia will be completed. Post 2017, NLH will be interconnected with the rest of the North American grid. In addition, there will be a long term sales agreement with Nova Scotia that will provide scheduling flexibility. NLH's current long term planning system does not reflect the reliability benefits of these incremental additions to the NLH portfolio.

Conclusion

NLH's generation planning reserve criterion of a LOLH of 2.8 hours per year is prudent and consistent with standard industry practices. NLH has consistently used the generation planning reserve criterion as an input to their capacity expansion optimization to ensure that all plans selected for comparison meet or exceed the minimum reliability threshold for a power system.

Recommendation

NLH should continue forward with its generation planning reserve criterion.

After completion of NLH's interconnection with Nova Scotia and Muskrat Falls, NLH should revisit their generation planning reserve criterion of 2.8 hours/year in light of the reliability benefits offered by the access to North American markets. It may be possible that this approach to reserve criterion, if still appropriate may be improved at minimum cost. In addition, NLH should continue their on-going efforts to include the modeling of external markets in Strategist to capture both the reliability benefits and market value of market interactions. In order to

[14] Newfoundland and Labrador Hydro, *PUB-NLH-056* (Newfoundland and Labrador Hydro: Board Response, February 2014),1

allow for a better understanding of the potentials of economy interchange Ventyx recommends NLH continues to pursue the Network Economy Interchange ("NEI") modeling effort.

Generation Forced Outage Rates

Background

The purpose of generation forced outage rates in generation planning is to represent the probability that a specific unit will not be available for service when required. Generation Planning periodically confirms the resource adequacy of a system through detailed reliability simulations that compare the expected load profiles with specific generating unit forced outage rates and maintenance schedule to determine LOLH values. A typical unit's contribution to resource adequacy is typically a function of the unit's capacity and its equivalent forced outage rate ("EFOR"). NLH uses the convention Derated Adjusted Forced Outage Rate ("DAFOR") which is known as EFOR as used by the North American Electric Reliability Council[15]. For the purposes of this report EFOR and DAFOR have the same meaning. A unit's equivalent forced outage rate is defined according to the following formula:

[15] Roy Billinton, *Reliability Data Requirements, Practices and Recommendations* (Department of Electrical Engineering University of Saskatchewan) page 55.

$$EFOR = \frac{FOH + EFDH}{FOH + SH + Synchronous\ Hrs + Pumping\ Hrs + EFDHRS} \times 100\%$$

Where:

FOH	– Forced Outage Hours
$EFDH$	– Equivalent Forced Derated Hours
SH	– Service Hours
$Synchronous\ Hrs$	– Synchronous Condensing Mode Hours
Pumping Hrs	– All hours pumped storage unit in pumping mode
$EFDHRS$	– Equivalent Forced Derated Hours during Reserve Shutdowns

For the purposes of this discussion, Ventyx focused on NLH's largest aggregate resources that drive overall system reliability, Holyrood, 465.5 MW; and Bay D'Espoir, 592 MW. These two plants comprise 1057.5 MW and represent 54.3% of NLH's installed capacity. The EFOR used in NLH's generation planning and serving as an input to Strategist is derived from the Canadian Electrical Association's ("CEA") 2004 Report and is based on the period from January 1, 2000 through December 31, 2004. Ventyx compared these rates to the current CEA data covering the period from January 1, 2008 through December 31, 2012. NLH's other smaller CT's and Hydro units have less impact upon reliability.

Table 3 lists the five year CEA capacity weighted average EFOR based on the most recent CEA data and the EFOR assumptions in NLH's Strategist database.

Unit Name	NLH Strategist Assumptions	NLH Average 2008 - 2012
Holyrood	9.64%	10.69%
Bay D'Espoir	0.91%	0.41%

Table 3

Conclusion

NLH's overall assumptions are consistent with industry standards. While there might be some rationalization that a significant increased investment might improve Holyrood performance further, given the time until the infeed is realized, the age of the units and outage availability it appears that the time required to gain results will be longer than the relatively short timeframe to interconnection with the North American Grid.

Recommendation

Since Holyrood is scheduled to be retired in the next 4 to 5 years NLH should model its EFOR close to the actuals currently being experienced with sensitivities on either side of the expected value. With respect to all other thermal units in the Strategist model (existing and future) NLH should continue its practice of modeling with a more conservative estimate of EFOR for the units. However, one refinement that NLH could make to its EFOR assumptions would be to tie the level of EFOR to typical maintenance cycles. There is an inherent relationship between higher capital expenditures and maintenance corresponding to lower EFOR. However, it should be noted that a five year rolling average will also account for these cycles. By ramping up the EFOR, in the years leading up to a major maintenance cycle, NLH would have a better picture of the near-term, one to five year, view of system reliability.

Alternatively, NLH could also compute a break-even EFOR for each class of its generation resources. For example consider the Holyrood Plant, for which the maximum EFOR would be between 9.7% and 9.8%. At this point, the units' contribution to LOLH would exceed 2.8 hours/year.

Scenario Planning

Background

The purpose of this part of the review is to examine the NLH planning process with respect to accepted utility practices and procedures. The standard that the NLH planning process was compared is the Ventyx Integrated Resource Planning ("IRP") process. This process was developed and used by Ventyx n its worldwide consulting practice.

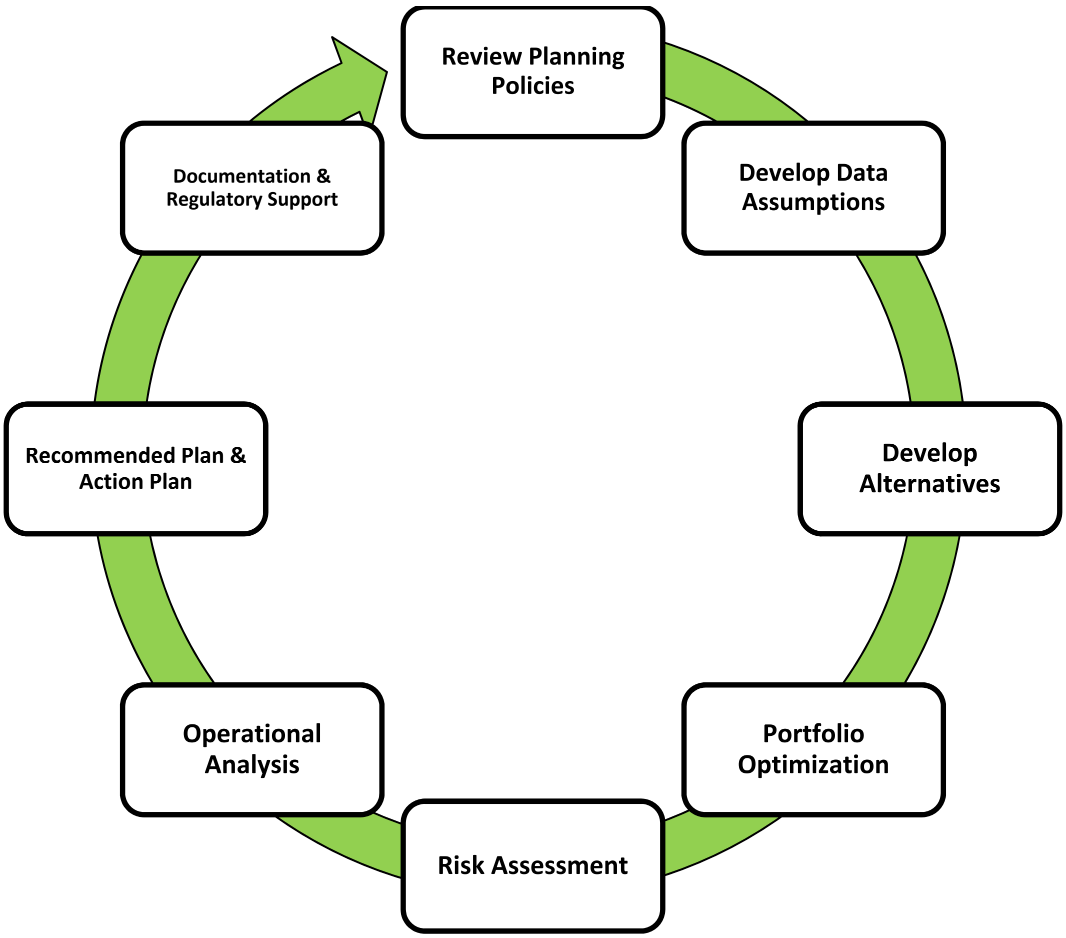

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Figure 2 IRP Planning Process

Description of each step:

- **Planning Policies Review** – This is the initial IRP project planning step in which the objectives of the IRP are set up. This includes the review of all of the rules and constraints that must be met in performing the planning process
- **Data Assumptions** – In this step all of the data assumptions are gathered and vetted. This includes the operating assumptions of all existing and proposed future alternatives, commodity prices, environmental and market prices, and transmission limits.
- **Develop Alternatives** – The simulation models for the various alternative Demand-side, Supply-side and market/transmission options are developed.
- **Portfolio Optimization** - In this step the potential resource alternatives are pre-screened using economic and operational methods. Through the use of optimization software, such as Strategist, one or more optimal plans are developed that meet a set of defined attributes and constraints.
- **Risk Assessment** - This step takes optimized plans from alternative scenarios and subjects them to sensitivity analysis to determine the impact of changes in assumptions to results. This step also determines the robustness of optimal plans to statistical distributions of sensitive variables. Then using multi-criteria decision making analysis techniques determines the trade-off between competing attributes such as risk and least cost.
- **Operation Analysis** – Selected plans are then further analyzed in terms of financial viability and operational constraints such as hydrological studies.
- **Recommended Plan and Action Plan** - The results of all the above steps is a recommended plan that the utility wished to present as its integrated resource Plan. In conjunction with this overall long –term plan an Action Plan is developed that focuses on the decision period in which actions must be decided on today. With-in the Action Plan a set of signposts are developed from the sensitivities that determine which variables should be monitored, at what value an action should be triggered, and what the contingent actions should be.

- **Documentation and Regulatory Support** –The heart of the IRP is the final documentation. These are the documents that will be filed with regulators and all other parties. It should be thorough, accurate and defendable. Note that this step is best performed as the overall IRP process is being performed.

The review of the resource planning process included a review of the original filings with the Board concerning the Muskrat Falls Project, review of two independent detailed reviews of the project, a review of the responses to the Board's questions concerning the incidents this winter, and one-on-one interviews with both NLH and NP planning staff.

Conclusions

The resource planning process being performed by NLH conforms to the basic structure laid out in the Ventyx IRP process. All areas in the IRP process were deemed as being acceptable. However, two areas, Alternative development, and Risk Assessment were found to be acceptable but in need of improvements.

In the development of alternatives it was found that although existing demand-side programs were included in the development of the resource plan there was a lack of additional demand-side alternatives. The report only mentions the presentation of CDM alternatives to the Board, no mention of the use of demand-side as alternatives to supply resources is made. Due to slow growth requirements of demand programs the use of demand-side alternative will not be effective to solve short-term issues. It will also not change the need for the capacity and energy from the Muskrat Falls project long term. However, it is Ventyx's recommendation that the use of demand-side alternatives be further explored in the period post 2017 while there is ample capacity to cover requirements. In reviewing the documents it was noted that there is no formal risk assessment being performed.

Sensitivities were performed and included in the original documentation but focused mostly on commodity and costing assumptions. Future scenario and sensitivity processes should be expanded to include the impacts of extreme loads. These expanded sensitivity analysis can then be formally included into a risk analyses process to determine the robustness and impacts of resulting plans. The additional load sensitivities are discussed above in the section on load forecast.

Recommendations

It is noted that while NLH's Resource Planning processes meets the overall IRP process requirements, there are two areas that could be incrementally improved.

Improve the resource planning process by:

- Beginning to explore the use of demand-side programs as long-term alternatives to future supply–side alternatives post 2017 and
- Expand the Risk Analysis sensitivities to include several levels of load forecast uncertainty.

Generation Outlook 2014 to 2017

On January 17th, the Board initiated a process to gather information from NLH and NP with a focus on whether load requirement on the Island Interconnected system can be met in the near term. In the near term, NLH's current resource expansion plan is within the reliability criteria.

	Loss of Load Hours (Hours)	Reserve Margin (Percent)
2013	0.97	16.32
2014	2.59	12.28
2015	3.98	10.32
2016	2.73	12.21
2017	2.68	11.00

The previous table is based on the assumption that a new 50 MW CT is in service December of 2015. If that unit does not achieve that commission date the LOLH would increase to 4.57.

NLH is currently considering six options[16] for meeting the expected LOLH in 2015. Each of these options offers the possibility to reduce the system LOLH.

1. Retain the 16 MW (10 MW to the system) diesel facility at Holyrood;
2. Review what is needed to make the remaining 4.6 MW of diesel power at Holyrood available to the system by plant modifications to increase equipment ratings to deliver 14.6 MW capacity;
3. Enter into interruptible contracts with large Industrial customers;
4. Seek already built combustion turbines in the 50 to 100 MW range to supply deficit and blackstart;
5. Initiate the supply of a new 60 MW (nominal) combustion turbine for the Holyrood site to supply deficit and blackstart; and
6. Continue and possibly enhance conservation and demand management initiatives, with the focus on demand management.

The new 60 MW (nominal) combustion turbine or other combustion turbine options are key resources for NLH's near term reliability of supply. The current plan has this unit commissioned in December of 2015. Without this unit, NLH would face LOLH reliability indices of 4.57 hours/year in 2015, 6.02 hours/year in 2016, and 5.71 hours/year in 2017, the Labrador Infeed is in service in December of 2017.

Statistically, demand reduction is a slightly better alternative to generation additions due to inherent uncertainty of generation forced outages. In order to reduce the expected 2015 LOLH of 3.98 hours/year to 2.80 hours/year, NLH would need to secure approximately 40 MW of either interruptible contracts with existing customers or conservation and demand

[16] Newfoundland and Labrador Hydro, *PUB-NLH-062* (Newfoundland and Labrador Hydro: Board Response, February 2014)

management initiatives. If that is not practical, then the difference can be made up from the remaining generation capacity options.

Furthermore, NLH uses reasonable estimates for generation forced outage assumptions as compared to Canadian Electricity Association (CEA) five year averages and the five year averages for its own equipment. The assumptions in Strategist are based upon data collected between 2000 and 2004. The generation forced outage assumption for Holyrood and Bay D'Espoir are 9.64%[17] and 0.91%[18], respectively, and they contributed to the forecast 2015 LOLH of 3.98 hours/year. Recent data from NLH operating data, from 2008 to 2012, indicates that the historical performance for Bay D'Espoir has improved to 0.41% and worsened for Holyrood to 10.69%. These figures are relatively consistent with current performance, however if the generation forced outage assumptions were improved for Bay D'Espoir, the 2015 LOLH would drop to 3.69 hours/year. If the generation forced outage assumptions were changed for Holyrood the contribution to the 2015 LOLH would increase to 4.49 hours/year.

The primary drivers are the Holyrood units. Focusing only on Holyrood, if Holyrood unit could achieve an annual forced outage rate of 8.48% or less then the system would achieve a LOLH of 2.8 hours/year. Recognizing the age of these assets this may not be practical in the short term and continuing the current assumptions is prudent planning, particular for the near term. As well there is merit in assessing some variation of this expected performance to gauge sensitivity on the LOLH result.

Summary of Recommendations

Ventyx has not found any evidence that either the generation planning process or the load forecasting process have contributed to the events of January.

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[17] Source: CEA Typical 2000-2004. Table 6.2.2 100-199 MW Classification for Holyrood.

[18] Source: NLH Operating Experience between 2000-2004. Weighted Average based on Bay D'Espoir units & Hinds Lake, Upper Salmon, Cat Arm and Paradise River

It was noted above that Ventyx does not believe it is desirable to change the forecast methodology to an end-use model. Primarily this is due to the increased complexity and cost, but it is also noted above that the major end-use on the system is electric heat and is already included in the forecast model and thus capturing the majority of any additional detail accuracy benefits that would be expected from an end use model. Since the R^2 for the two regression equations involving heating penetrations were 79% and 89% it would be advisable that NLH continue to refine its models with respect to these two variables. This can be further enhanced through continued surveying of the customer base in terms of both average use and saturation of this end use.

The above discussion has been in terms of the base-case scenario. It has been recommended above that NL begin using a formal risk assessment process that includes the evaluation of plans under extreme weather conditions. As such, it will be important to develop alternative load forecast in both the scenario development and the sensitivity analysis phases.

NLH should continue to use its generation planning reserve criterion.

After completion of NLH's interconnection with Nova Scotia and Muskrat Falls, NLH should revisit their generation planning reserve criterion of 2.8 hours/year in light of the reliability benefits offered by the access to North American markets. In addition, NLH should continue their on-going efforts to include the modeling of external markets in Strategist to capture both the reliability benefits and market value of market interactions. In order to allow for a better understanding of the potentials of economy interchange Ventyx recommends NLH continues to pursue the Network Economy Interchange ("NEI") modeling effort.

Since Holyrood is scheduled to be retired in the next 4 to 5 years NLH should model it's EFOR close to the actuals currently being experienced with sensitivities on either side of the expected value. With respect to all other thermal units in the Strategist model (existing and future) NLH should continue its practice of modeling with a more conservative estimate of EFOR for the units. However, one refinement that NLH could make to its EFOR assumptions would be to tie the level of EFOR to typical maintenance cycles. There is an inherent relationship between higher capital expenditures and maintenance corresponding to lower EFOR. However, it should be noted that a five year rolling average will also account for these cycles. By ramping up the

EFOR, in the years leading up to a major maintenance cycle, NLH would have a better picture of the near-term, one to five year, view of system reliability.

Alternatively, NLH could also compute a break-even EFOR for each class of its generation resources. For example consider the Holyrood Plant, the maximum EFOR would be between 9.7% and 9.8%. At this point, the unit's contribution to LOLH would exceed 2.8 hours/year.

Improve the resource planning process by:

- Beginning to explore the use of demand-side programs as long-term alternative to future supply–side alternatives post 2017 and
- Expand the Risk Analysis sensitivities to include several levels of load forecast uncertainty.

Appendices

PUB-NLH-008

PUB-NLH-011

PUB-NLH-056

PUB-NLH-062

Q. How does Hydro determine the appropriate reserve to have available to meet the Island Interconnected system load?

A. From a long-term planning perspective, Hydro has established criteria related to the appropriate reliability for the system, at the generation level, that sets the timing of generation source additions. These criteria set the minimum level of reserve capacity and energy installed in the system to ensure an adequate supply for firm demand; however, short-term deficiencies can be tolerated if the deficiencies are of minimal incremental risk. As a general rule to guide Hydro's planning activities the following have been adopted:

Capacity: The Island Interconnected System should have sufficient generating capacity to satisfy a Loss of Load Hours (LOLH) expectation target of not more than 2.8 hours per year[19].

[19] LOLH is a statistical assessment of the risk that the System will not be capable of serving the System's firm load for all hours of the year. For Hydro, an LOLH expectation target of not more than 2.8 hours per year represents the inability to serve all firm load for no more than 2.8 hours in a given year.

Energy: The Island Interconnected System should have sufficient generating capability to supply all of its firm energy requirements with firm system capability[20].

From an operational perspective, Hydro manages generation resource availability on the Island Interconnected System and schedules generating units out of service for planned maintenance in order to meet a (n-1) system contingency reserve criterion. In this manner, sufficient reserves are planned to be available to meet the Island Interconnected System load under a contingency of the largest (MW rating) available generating unit. Hydro does not rely on capacity from wind and other non-dispatchable[21] resources to provide reserve. However, if these resources are in production they can further increase the reserves available. Following the (n-1) criterion results in no extended planned maintenance scheduled during the winter period. However, if the short-term load forecast permits, Hydro may take the opportunity to schedule a short duration generating unit outage to address running or corrective maintenance issues.

[20] Firm capability for the hydroelectric resources is the firm energy capability of those resources under the most adverse three-year sequence of reservoir inflows occurring within the historical record. Firm capability for the thermal resources (Holyrood Generation) is based on energy capability adjusted for maintenance and forced outages.

[21] Please refer to PUB-NLH-044 for a definition of "non-dispatchable".

Q. Provide the forecast and actual peak demand for each month in the winter period in each year from 2004 to 2013 and the forecast each year for 2014 to 2017 for each month in the winter period.

A. Please see below for the forecast and actual peak demand supplied by Hydro for the Island Interconnected System. Please note that Hydro interprets the winter period to be from December through March and that the forecasts provided are Hydro's Operating Load Forecasts. Please refer to Hydro's response to PUB-NLH-014 on timing of preparation.

Island Interconnected System Supply Issues and Power Outages

NLH System Peak Demand (MW)

	Forecast	Actual
Jan-04	1399	1277
Feb-04	1338	1405
Mar-04	1237	1206
Dec-04	1374	1402
Jan-05	1429	1361
Feb-05	1405	1272
Mar-05	1301	1161
Dec-05	1353	1202
Jan-06	1385	1276
Feb-06	1369	1185
Mar-06	1256	1167
Dec-06	1333	1310
Jan-07	1358	1323
Feb-07	1350	1249
Mar-07	1238	1242
Dec-07	1336	1286
Jan-08	1367	1289
Feb-08	1356	1212
Mar-08	1242	1207
Dec-08	1350	1323
Jan-09	1388	1390
Feb-09	1377	1375
Mar-09	1262	1294
Dec-09	1349	1268

Island Interconnected System Supply Issues and Power Outages

NLH System Peak Demand (MW)

	Forecast	Actual
Jan-10	1372	1253
Feb-10	1361	1305
Mar-10	1243	1142
Dec-10	1371	1207
Jan-11	1401	1278
Feb-11	1390	1292
Mar-11	1270	1200
Dec-11	1405	1399
Jan-12	1433	1385
Feb-12	1417	1350
Mar-12	1302	1341
Dec-12	1432	1307
Jan-13	1461	1378
Feb-13	1446	1374
Mar-13	1332	1272
Dec-13	1401	1501
Jan-14	1478	-
Feb-14	1429	-
Mar-14	1322	-
Dec-14	1425	-
Jan-15	1523	-
Feb-15	1470	-
Mar-15	1361	-
Dec-15	1447	-
Jan-16	1543	-
Feb-16	1498	-
Mar-16	1383	-
Dec-16	1466	-
Jan-17	1567	-
Feb-17	1515	-
Mar-17	1395	-
Dec-17	1473	-

Note: Forecast and actual peaks reflect gross requirements.

Q. Further to the response to PUB-NLH-008, state the date(s) the criteria used for generation source additions was last reviewed by Hydro. In the response state whether Hydro is of the opinion it should be reviewed in light of Hydro's aging infrastructure and when is the appropriate time to review this criteria.

A. Hydro's generation source additions criteria have been in use for over 35 years and in that period they have been reviewed on a number of different occasions and found to provide a good balance of reliability versus cost.

Before 1977, there were no approved long-term reliability criteria for generation planning in Hydro. The basis of the current criteria is a report, *Recommended Loss of Load Probability (LOLP) Index for Establishing Generation Reserve Additions*, System Planning Department, May 16, 1977. In that report, a LOLP of 0.2 days per year, or 1 day in 5 years was established. In 1997, when Hydro replaced the SYPCO generation planning software with ProScreen II (now renamed Strategist) generation planning software, it was necessary to switch to a Loss of Load Hours (LOLH) criterion. Benchmarking established that a LOLH of 2.8 hours per year was equivalent to a LOLP of 0.2 days per year, for Hydro's system. From that point onward, Hydro established the capacity criteria that the Island Interconnected System should have sufficient generating capacity to satisfy an LOLH expectation target of not more than 2.8 hours per year.

In 1991, at the direction of the Board, George C. Baker, a consultant working for Hiltz and Seamone Company Limited carried out a study and produced a report -*Report on the Technical Performance of Newfoundland & Labrador Hydro* - October 2, 1991. On page 9 of the report, in Section *7 System Planning,* it states:

Hydro uses two criteria for generation planning in its interconnected system.

(a) Sufficient production capacity to meet all needs under firm water conditions (lowest recorded flows), and

(b) A loss of load expectancy of one day in five years.

The first criterion is usual for utilities with significant dependence on hydraulic generation. The second differs from the one-day-in-ten-years LOLE[22] *adopted by many utilities.*

The main reason for permitting a higher LOLE is economic. Hydro, unlike almost every other major utility, is an isolated system. Other utilities can, and do, rely on capacity support from interconnected utilities in meeting the one-day-in-ten-years criterion. Hydro cannot do this, and would have to maintain a much higher generation reserve.

[22] Loss of Load Expectation. LOLE is another way of stating LOLP and the two are equivalent.

Hydro believes the costs of doing so would not be justified by the difference in reliability. The Consultant agrees.

In 1999, at the direction of the Board, Quetta Inc. and Associates carried out a study and produced a report *Technical Review of Newfoundland and Labrador Hydro Final Report* March 17, 1999. On page 23 of the report, in Section *2.1.3.2 Capacity*, it states:

The Island Interconnected System should have sufficient generating capacity to satisfy a Loss of Load Expectation (LOLE) target of not more than 2.8 hours per year. This is equivalent to 0.2 days/year or 1 day in five years. It results in a capacity reserve requirement of 18%.

The LOLE capacity criterion is somewhat less stringent than that employed by large interconnected systems in the rest of North America (one day in 10 years or 0.1 days/year). Considering the non-interconnected status of the Island's electric utility system, (reserve sharing is not an option) the cost of providing higher reliability level is probably in excess of the benefits to be derived.

Quetta is of the opinion that the capacity and energy criteria are reasonable in the circumstance.

Most recently, the criteria were reviewed in the *Report on Two Generation Expansion Alternatives for the Island Interconnected Electrical System – Volume 2: Studies January 2012*. This report was prepared for the Board by Manitoba Hydro International. In the report, *Section 3 – Reliability Studies* runs from page 57 to page 71. *Section 3.11 – Conclusions and Findings*, page 70, states the following:

Available documentation for reliability assessment performed by Nalcor has been reviewed by MHI. The adequacy criteria of 2.8 hours/year of loss of load expectation for resource planning, which considers both generation resource availability and economics, appears reasonable when compared to practices of other operating utilities.

As part of its internal review of recent events, Hydro has engaged an outside consultant (Ventyx) to review its generation planning practices. One of the areas to be reviewed is the criteria used for generation source additions. As well, in light of Hydro's aging infrastructure, it is also appropriate to review the inputs to the generation expansion model, such as the current and expected forced outage rates of Hydro's generating units. These will also be reviewed.

Q. Further to the response to PUB-NLH-018, which states that there is a capacity deficit identified for 2015, explain in detail each of the "*several generating options potentially available to meet winter peak demand*" that Hydro stated it was pursuing, including the status of the review of each option and the time required to construct or install each option.

A. The options under consideration for meeting the deficit currently expected in 2015 include the following and may be a combination of two or more to meet the potential deficit:

1. **Retain the 16 MW diesel facility at Holyrood (presently under a lease-to-own arrangement).** Once installed, 10 MW can immediately be supplied to the system on a sustained basis. This facility is currently being prepared for commissioning in early March 2014.
2. **Review what is needed to make the remaining diesel power available to the system.** Please refer to Hydro's response to PUB-NLH-064.
3. **Enter into interruptible contracts with large Industrial Customers.** Discussions with Industrial Customers (CBPP, Vale and North Atlantic Refining) were initiated in fall 2013. These discussions are ongoing and options continue to be explored. Please refer to Hydro's response to PUB-NLH-050.
4. **Seek already built combustion turbines in the 50 to 85 MW range**. Preliminary discussions indicate that these options can provide in-service to meet the 2015 requirement. However, discussions with manufacturers, brokers and owners are

ongoing to determine the delivery times, operating experiences, the extent of modifications required, and the facilities required to connect to the Island Interconnected System.

5. **Initiate the supply of a new 60MW (nominal) combustion turbine for the Holyrood site to supply deficit and blackstart functionality.** All preliminary engineering is complete. With final approval by June 2014, this plant could be in-service by 2015.
6. **Conservation and demand management initiatives, with the focus on demand management**. Work is being conducted to assess customer end use options with a view of providing demand management. This is considered a supplemental means of meeting the deficit and may provide further cost savings opportunities when combined with other options.

APPENDIX F

Risk Workshop

WorleyParsons
resources & energy

nalcor energy

Combustion Turbine (CT) Addition Project Site Alternatives- HRD, HWD, 74L

Risk Management Report

Disclaimer

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Contents

Appendices

EXECUTIVE SUMMARY

This risk assessment workshop was held on *March 8 and 9, 2012* on Level 3 Conference Room 1 in order to review and identify both the Opportunities and Risks associated with the *CT Addition* project site alternatives.

Three separate sessions were conducted to address risks and opportunities associated with three potential sites for this project. The three sites were HRD, HWD and 74L.

The table below summarizes the top 5 risks for each site.

HRD	74L	HWD
EA release does not get approved leading to unsuitable installation at HRD	Acquisition of land process is delayed leading to delay in project schedule.	EA release does not get approved leading to unsuitable installation at HWD
EIS or EPR required leads to delay in schedule	EA release does not get approved leading to unsuitable installation at 74L	EA process leads to a public hearing which negatively impacts reputation
EA process leads to a public hearing which negatively impacts reputation	Supplier delivery (CT, Transformer) is longer than scheduled leading to delay	EIS or EPR required leads to delay in schedule
Supplier delivery (CT, Transformer) is longer than scheduled leading to delay	Contamination is discovered when in construction leads to delay in schedule	Precedent is set with installation of new technology leading to demands to improve existing - cost impact
CT not situated in the 66kV loop leading to greater and different unserved load and advanced transformer investment in St. John's area.	Unknown environmental risks lead to suspension of operations.	Physical space in existing terminal station is insufficient to install new CT

Actions have been developed to address the key risks identified for the project. Even after treatment, a number of risks remain 'Extreme' and 'High' and will remain so unless additional mitigation actions are in implemented.

The following table summarizes the post treatment state.

Post Treatment Ranking	Extreme	High
HRD	0	6
74L	0	8
HWD	2	6

As part of the assessment a number of opportunities were also identified. The following table summarized the number of opportunities per location.

Opportunities	
HRD	9
74L	5
HWD	3

INTRODUCTION

This Risk Management Report has been developed by the Nalcor Project stakeholders for the CT Addition Project.

A formal risk management session was held in Level 3 Conference Room 1 on March 8 and 9, 2012, and this report summarises the main findings of that forum. Attendees at the forum included representatives from System Operations, System Planning, Environment, PETS and Long Term Asset Planning.

A number of action items are proposed in this report to mitigate and control the risks identified for this project. It is recommended that these actions are taken and further developed by the project team for the final site alternative and that this report should be monitored and updated regularly as part of the on-going execution of the project.

The Project Manager is responsible for maintaining the Risk Management Plan as a 'live' document and for ensuring that the action items are implemented and monitored throughout the project life cycle.

1.1 Scope & Project Context

The activities and operations associated with this risk assessment workshop report include-

- *Siting Study;*
- *Installation of a new 50 MW (minimal) Combustion Turbine at one of three locations*
    - *Holyrood Generating Station – HRD*
    - *Hardwoods 50 MW Gas Turbine Site – HWD*
    - *74L – Newfoundland Power right of way on the east end of St. John's*
- *Depending on the location selected, the scope may include procurement and installation of the turbine, transmission line modification, procurement and installation of a power transformer and other major electrical equipment, fuel storage tanks and transfer system, access road, and civil works, possibly including an enclosure for the turbine, environmental assessment and related activities.*
- *Post project operations at a high level.*

Exclusions include-

- *Any other sites in addition to those indicated above*
- *Any other sources of generation*
- *Detailed discussions of post-project Operating considerations*
- *Detailed site-specific project execution activities*

Assumptions include-

- *Sanction of the Lower Churchill Project; and*
- *Project in service to meet 2015/2016 peak*

Limitations include-

- *Known public acceptance of installing the new facility at either location*
- *Knowledge of design details*
- *System capability of black starting HRD from HWD or 74L*
- *Unknown fuel storage requirement*

2. RISK ASSESSMENT PROCESS

WorleyParsons has used a formalised process for the identification and management of business and project risks for a number of years, both on behalf of their customers and for their own internal purposes. The basic driver behind these processes is to identify and manage business and project risks so that the best objectives can be achieved.

The process that WorleyParsons uses is based broadly on the International Standard, ISO 31000:2009, "*Risk Management- Principles and guidelines*".

The qualitative process involves the following steps:

- The business/project risks are identified, generally by a facilitated brainstorming session involving key stakeholders in the project;
- The risks are evaluated, analysed and prioritised into broad categories (e.g. extreme, high, medium and low risks), based on the likelihood of the risk occurring, and the consequences if it were to occur;
- The critical risks are assessed and treated – treatment can include actions to reduce either the likelihood or the consequences or both, the off-loading of risks to another party more suitable to accept such risks, or the acceptance and on-going management of a risk. The treatment of a risk may involve allocating some money to cover the treatment.
- Opportunities are also identified utilising this process by focusing on the possible additional benefits which could be extracted.

The output form this process is a Risk Management Plan, which includes the following documents:

- Risk Maps, before and after treatment;
- Risk Register, Risk Treatment Plan and Risk Action Plan.

These documents form part of the strategic project management process for the project, and must be communicated to the project team and monitored, reviewed and update progressively throughout the project execution.

3. RISK ASSESSMENT WORKSHOP

The risk workshop was conducted in accordance with guidance given in ISO 31000 and recorded in a spreadsheet format utilising a structured brainstorming approach.

The risk identification process was assisted with the use of guidewords, and drew on the experience of the assembled workshop participants.

Where a risk was identified and considered credible, the current controls and possible consequences were discussed and recorded. The risk associated with the identified risk were then characterised based on the identified consequence and likelihood of occurrence using a 5x5 risk matrix.

3.1 Risk Evaluation Scales

This section details the scales utilised for this project risk workshop.

3.1.1 Consequence Scales

The Workshop Attendees reviewed the suggested risk consequences and agreed on the following scale for this workshop:

	Consequence Category				
	Insignificant	**Minor**	**Moderate**	**Major**	**Catastrophic**
Safety	**First Aid Case**	**Minor Injury,** Medical Treatment Case with/or Restricted Work Case.	**Serious injury** or Lost Work Case	**Major or Multiple Injuries** permanent injury or disability	**Single or Multiple Fatalities**
Environment	**No impact** on baseline environment. Localized to point source. No recovery required	**Localized** within site boundaries. Recovery measurable within 1 month of impact	**Moderate** harm with possible wider effect. Recovery in 1 year	**Significant** harm with local effect. Recovery longer than 1 year.	**Significant** harm with widespread effect. Recovery longer than 1 year. Limited prospect of full recovery
Financial	<$100,000	$100k - $500k	$500k - $5m	$5m - $10M	>$10m
Lost Production OR Schedule Slippage	Up to 3 days	3 days – 1 week	1 wk – 1 month	1 – 6 months	> 6 months
Reputation	Localised temporary impact	Localised, short term impact	Localised, long term impact but manageable	Localised, long term impact with unmanageable outcomes	Long term regional impact
Management Effort	Impact can be absorbed through normal activity	An adverse event which can be absorbed with some management effort	A serious event which requires additional management effort	A critical event which requires extraordinary management effort	Disaster with potential to lead to collapse of the project

3.1.2 Likelihood Scales

The Workshop utilised the following likelihood scale for this workshop:

Rare	Unlikely	Moderate	Likely	Almost Certain
5% chance of occurring	20% chance of occurring	50% chance of occurring	80% chance of occurring	95% chance of occurring

3.1.3 Risk Matrix

		Consequence				
		Insignificant	Minor	Moderate	Major	Catastrophic
Likelihood	Almost Certain	H	H	E	E	E
	Likely	M	H	H	E	E
	Moderate	L	M	H	E	E
	Unlikely	L	L	M	H	E
	Rare	L	L	M	H	H

Once evaluated, the above risk matrix allows risks to be prioritised for action/risk treatment.

Risk Severity Rating	Priority (1 is highest)	Action Required
E - Extreme	1	Immediate attention
H - High	2	Immediate attention

M - Moderate	3	Action as soon as practicable
L - Low	4	Low priority

3.2 Risk Treatment

Where the risks were evaluated and deemed intolerable by the workshop participants, risk treatment or 'action plans' were identified. For completeness and to check their effectiveness, the risk severity before and after treatment (i.e. with the action plan in place) were determined.

3.3 Workshop Attendees

The workshop was conducted on March 8 and 9, 2012 on Level 3 at Conference Room 1.

The workshop attendees are given in Table 1~~Table 1~~.

Table 1 Workshop Attendees

Name	Position
Howard Richards	Project Manager
Terry LeDrew	Manager Thermal Generation
Jim Haynes	VP Regulated Operations
John MacIsaac	VP PETS
Hughie Ireland	Manager LTAP
Bob Butler	Supt. ECC
Paul Humphries	Manager System Planning
Frank Ricketts	Manager Environmental Services
Stephen Fitzpatrick	Worley Parsons Facilitator/Program Manager TRO

Apologies included-

- Alberta Marche – Manager of Project Execution - Regulated

4. RISK WORKSHOP RESULTS

4.1 Stakeholders Identified

The following key Stakeholders were identified by the Risk Workshop Team:

• PUB	• Newfoundland Power
• Customers	• Nalcor
• Contractors	• Lower Churchill Project
• ECC	• Employees at HRD
• Operations/Work Execution	• Community Liaison Committee for HRD location
• Project Execution	• Local landowners surrounding the facility
• LTAP	• Provincial Government
• Technical Services	• HRD
• Safety and Health	• Town of Holyrood – for HRD site
• Environmental Services	• Town of CBS – for HRD site
• Town of Paradise – for HWD site	• City of St. John's - for 74L site

4.2 Key Success Factors Identified

The following Key Success Factors were identified by the Risk Workshop Team:

• Zero Harm	• Stakeholders are regularly informed on status
• Project completion by the peak of 2014/2015	• Provide black start capability to HRD

• Minimal environmental impact	• Meet system planning requirements to meet demand until Lower Churchill Island Infeed In Service – 2017
• Reliable operation after project complete	• Decision to proceed by March 2012
• Project completed within budget	• Installation meets standard design criteria

4.3 Risk Assessment Summary

Three separate workshops were completed, one for each potential location.

For HRD, a total of *25* risks were identified.

Risk Summary

Threats

Rank	No.	Description	Before		After
1	4	EA release does not get approved leading to unsuitable installation at HRD	High		High
2	5	EIS or EPR required leads to delay in schedule	High		High
3	8	EA process leads to a public hearing which negatively impacts reputation	High		High
4	9	Supplier delivery (CT, Transformer) is longer than scheduled leading to delay	High		High
9	6	CT not situated in the 66kV loop leading to greater and different unserved load and advanced transformer investment in St. John's area.	High		High
10	16	PUB approval is delayed leading to reputational impact due to proceeding prior to approval.	High		High
6	12	PUB is not aware of this project leading to reputation impact	High		Moderate
7	13	If Lower Churchill does not proceed, this project is not the lowest cost option leading to reputation impact with PUB	High		Moderate
8	14	groundwater contamination during operation	High		Moderate
11	17	Increased tanker traffic leads to safety incident	High		Moderate
13	29	Airborne contaminants (ocean spray - salt) lead to increased corrosion rates on equipment and reduced reliability leading to supply issues	High		Moderate
15	20	Increased tanker delivery leads to environmental incident	Moderate		Moderate

16	15	Emissions modelling leads to potential environmental mitigation requirements leading to additional cost	Moderate	Moderate
17	23	New installation leads to emissions complaints leading to reputational impact	Moderate	Moderate
18	26	unable to go to synch condense mode without gas turbine running leads to reduced reliability	Moderate	Moderate
19	27	groundwater contamination during construction	Moderate	Moderate
5	11	Contamination is discovered when in construction leads to delay in schedule	High	Low
12	19	Project resource (people) unavailability leads to delay in project schedule	High	Low
14	22	Installation of a new CT at Holyrood contradicts previous message to public leading to reputation impact.	High	Low
20	18	Damage to existing equipment during construction leads to unplanned outage (buried cable, for example)	Low	Low
21	28	Additional tankage required leads to complaints	Low	Low
22	30	Unfamiliar equipment is installed leading to delay in commissioning and project schedule	Low	Low
23	33	Construction noise leads to complaints	Low	Low
24	25	Security and safety incident as a result of increased activity	Low	Low
25	32	Increased tanker traffic leads to complaints	Low	Low

For 74L, a total of 34 risks were identified.

Risk Summary

Threats

Rank	No.	Description	Before	After
1	8	Acquisition of land process is delayed leading to delay in project schedule.	Extreme	High
2	6	EA release does not get approved leading to unsuitable installation at 74L	High	High
4	11	Supplier delivery (CT, Transformer) is longer than scheduled leading to delay	High	High
5	13	Contamination is discovered when in construction leads to delay in schedule	High	High
8	38	Unknown environmental risks lead to suspension of operations.	High	High
10	18	PUB approval is delayed leading to reputational impact due to proceeding prior to approval.	High	High
11	19	Increased tanker traffic leads to safety incident	High	High
13	22	Increased tanker delivery leads to environmental incident	High	High
3	7	EIS or EPR required leads to delay in schedule	High	Moderate
6	14	PUB is not aware of this project leading to reputation impact	High	Moderate
7	15	If Lower Churchill does not proceed, this project is not the lowest cost option leading to reputation impact with PUB	High	Moderate
9	16	groundwater contamination during operation	High	Moderate
15	10	EA process leads to a public hearing which negatively impacts reputation	Moderate	Moderate
16	12	Black start at HRD - transmission must be available to allow this to happen - could result in inability to start HRD leading to production impact	Moderate	Moderate
17	27	Required to expropriate land to facilitate the new installation leads to reputation issue.	Moderate	Moderate
18	29	unable to go to synch condense mode without gas turbine running leads to reduced reliability	Moderate	Moderate
19	37	Airborne contaminants (ocean spray - salt) lead to increased corrosion rates on equipment and reduced reliability leading to supply issues	Moderate	Moderate
20	40	Fuel spill during delivery leads to reputational impact	Moderate	Moderate
21	4	Archaeological and cultural discovery leads to delay in schedule	Moderate	Moderate
22	3	New site with shared operator leads to delayed response time.	Moderate	Moderate
23	23	Recreational impact leads to reputation impact	Moderate	Moderate
24	30	groundwater contamination during construction	Moderate	Moderate
25	39	Site services are not available leading to additional costs to the project	Moderate	Moderate
12	21	Project resource (people) unavailability leads to delay in project schedule	High	Low

14	28	Unforeseen costs as a result of new installation lead to budget exceedance	High	Low
26	20	Wetland impacts due to new installation lead to budget exceedance	Low	Low
27	25	New installation leads to noise complaints leading to reputational impact	Low	Low
28	26	New installation leads to emissions complaints leading to reputational impact	Low	Low
29	32	Additional development to satisfy surrounding landowners leads to budget exceedance	Low	Low
30	33	Unfamiliar equipment is installed leading to delay in commissioning and project schedule	Low	Low
31	34	Noise during construction leads to reputational impact.	Low	Low
32	9	Concerns on electromagnetic field impact leads to public reputation.	Low	Low
33	35	Increased tanker traffic leads to complaints	Low	Low
34	36	Zoning issues lead to delay in schedule	Low	Low

For HWD, a total of 30 risks were identified.

Risk Summary

Threats

Rank	No.	Description	Before		After
1	1	EA release does not get approved leading to unsuitable installation at HWD	Extreme		Extreme
5	21	EA process leads to a public hearing which negatively impacts reputation	Extreme		Extreme
2	2	EIS or EPR required leads to delay in schedule	Extreme		High
4	9	Precedent is set with installation of new technology leading to demands to improve existing - cost impact	Extreme		High
6	5	Supplier delivery (CT, Transformer) is longer than scheduled leading to delay	High		High
10	10	Black start at HRD - transmission must be available to allow this to happen - could result in inability to start HRD leading to production impact	High		High
12	30	Two turbines in one location - transmission failure leads to reduction in supply. - black start	High		High
13	4	PUB approval is delayed leading to reputational impact due to proceeding prior to approval.	High		High
3	3	Physical space in existing terminal station is insufficient to install new CT	Extreme		Moderate
8	26	PUB is not aware of this project leading to reputation impact	High		Moderate
9	27	If Lower Churchill does not proceed, this project is not the lowest cost option leading to reputation impact with PUB	High		Moderate
11	8	groundwater contamination during operation	High		Moderate
14	13	Increased tanker traffic leads to safety incident	High		Moderate
15	16	Damage to existing equipment during construction leads to unplanned outage (buried cable, for example)	High		Moderate
17	33	Increased tanker delivery leads to environmental incident	High		Moderate
18	18	Construction leads to increased planned outages leading to reduction in reliability	High		Moderate
20	6	New installation leads to noise complaints leading to reputational impact	Moderate		Moderate
21	7	New installation leads to emissions complaints leading to reputational impact	Moderate		Moderate
22	14	Shared equipment between CTs leads to common mode unavailability - production loss	Moderate		Moderate
23	19	Maintenance at this site will be done in a tighter area leading to safety incident potential	Moderate		Moderate

24	24	unable to go to synch condense mode without gas turbine running leads to reduced reliability	Moderate	Moderate
25	32	groundwater contamination during construction	Moderate	Moderate
7	15	Contamination is discovered when in construction leads to delay in schedule	High	Low
16	29	Project resource (people) unavailability leads to delay in project schedule	High	Low
19	20	Congested area leads to additional cost to do maintenance in the facility	High	Low
26	12	Additional tankage required leads to complaints	Low	Low
27	17	Additional development to satisfy surrounding landowners leads to budget exceedance	Low	Low
28	28	Unfamiliar equipment is installed leading to delay in commissioning and project schedule	Low	Low
29	31	Noise during construction leads to reputational impact.	Low	Low
30	11	Increased tanker traffic leads to complaints	Low	Low

Risk treatment has been applied where appropriate and action plans identified to reduce the risks.

The full workshop risk assessment findings are presented as Appendix 1 including all of the action plans identified. The workshop notes should be read in their entirety and responsibilities and completion dates need to be assigned as part of this review. Appendix 2 presents the before and after treatment risk maps.

4.4 Opportunities Assessment Summary

For HRD, a total of *9* opportunities were identified.

1	Operator is familiar with existing facility and can quickly come up to speed on the new CT or help to train
2	Organization that focused on environmental and operational issues at Holyrood - more directed concerns as a result of installation.
3	No new transmission requirements
7	ECC control in HRD - local staff to support installation
10	Black start on site and does not require significant transmission path
21	Can build installation and tie in without requirement for major outage.
24	Retain some key employees as a result of 50MW installation at HRD
31	Existing air monitoring equipment and CEM at this site
34	Infrastructure available at HRD to support new CT. Fire suppression, utilities, security, etc…

For 74L, a total of 5 opportunities were identified.

1	Increased reliability for the St. John's and area load by situating inside the 66kV loop.
2	Provides future expansion capability both for Gas Turbine and for distribution
5	No new transmission requirements
17	Future prospects to use methane collected at Robin Hood Bay

24	Locating near the dump leads to cogen opportunity

For HWD, a total of 3 opportunities were identified.

22	Operator is familiar with existing facility and can quickly come up to speed on the new CT or help to train
23	CT situated within the 66 kV loop leads to easier management of St. John's area
25	No new transmission requirements

5. CONCLUSIONS & RECOMMENDATIONS

The Risk Management Plan should be reviewed *on a monthly basis* as specified in the Project Management Plan to ensure that appropriate actions have been taken and followed up. Once a final site has been selected, the Risk Management Plan will be updated and reviewed with the Project Team to ensure that design and other project activities take into consideration the existing identified risks and any other newly identified risks during project execution. Reviews should also occur at the commencement of a new project phase or if there are significant changes to the project scope or operating environment.

The Risk Management Plan, including action parties and forecast action close-out dates, is a “live” document and as such, should be maintained on the project schedule. The Risk Management Plan attached is the current version resulting from the risk management session.

6. REFERENCES

1. ISO 31000:2009, “*Risk Management- Principles and guidelines*”

Appendix 1A – Risk & Opportunity Register & Actions HRD

Appendix 1B – Risk & Opportunity Register & Actions 74L

Appendix 1C – Risk & Opportunity Register & Actions HWD

Appendix 2A – Risk Map (Before & After Treatment) – HRD

Appendix 2B – Risk Map (Before & After Treatment) – 74L

Appendix 2C – Risk Map (Before & After Treatment) – HWD

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Client:	**Regulated Operations**
Project:	**CT Addition - 74L**
Title:	**Risk Workshop**
Date:	**8-March-2012**

Facilitator: Stephen Fitzpatrick

Attendees:

Howard Richards
Terry LeDrew
Jim Haynes
John MacIsaac
Hughie Ireland
Bob Butler
Frank Ricketts

Context for Risk Workshop:

The purpose of this Risk Workshop is to determine the risks associated with installation of a new Combustion Turbine facility at 74L. The risks will encompass all aspects of the project from safety, social and environmental impacts to cost and schedule. This workshop will also include risks associated with operations as a result of the location and installation provided.

Stakeholders:

1 PUB
2 Customers
3 Contractors
4 ECC
5 Operations/Work Execution
6 Project Execution
7 LTAP
8 Technical Services
9 Safety and Health
10 Environmental Services
11 Newfoundland Power
12 Nalcor
13 Lower Churchill Project
14 City of St. John's
15 Local businesses surrounding facility
16 Local landowners surrounding facility
17 Provincial government
18 Holyrood Generating Station
19 Federal government - property owners
20 East Coast Trail Organization
21 Community of Logy Bay/Outer Cove/Middle

Key Success Factors:

1 Zero Harm
2 Project Completion by the peak of 2014/2015 (Delivery duration is 24 months)
3 Minimal environmental impact.
4 Reliable operation after project complete
5 Project completed within budget
6 Stakeholders are regularly informed on status.
7 Provide black start capability to HRD
8 Meet system planning requirements to meet demand until Lower Churchill on line - 2017
9 Decision to proceed by March 2012
10 Installation meets standard design criteria.

Below are some **suggested** likelihood and consequence scales.
Project teams are advised to review the categories and determine a scale that is relevant to their project; in particular the 'Financial' and 'Production/Schedule' categories should be modified to be specific to each Project. All fields should be reviewed and amended/deleted as required prior to commencing the brainstorming session.

Likelihood Category				
E	**D**	**C**	**B**	**A**
Rare	**Unlikely**	**Moderate**	**Likely**	**Almost Certain**
Highly unlikely to occur on this project	Given current practices and procedures, this incident is unlikely to occur on this project	Incident has occurred on a similar project	Incident is likely to occur on this project	Incident is very likely to occur on this project, possibly several times
OR				
5% chance of occuring	20% chance of occuring	50% chance of occuring	80% chance of occuring	95% chance of occuring

	Consequences				
	1 - Insignificant	**2 - Minor**	**3 - Moderate**	**4 - Major**	**5 - Catastrophic**
Safety and Health	**First Aid Case**	**Minor Injury,** Medical Treatment Case with/or Restricted Work Case.	**Serious injury** or Lost Work Case	**Major or Multiple Injuries** permanent injury or disability	**Single or Multiple Fatalities**
Environment	**No impact** on baseline environment. Localized to point source. No recovery required	**Localized** within site boundaries. Recovery measurable within 1 month of impact	**Moderate** harm with possible wider effect. Recovery in 1 year	**Significant** harm with local effect. Recovery longer than 1 year.	**Significant** harm with widespread effect. Recovery longer than 1 year. Limited prospect of full recovery
Financial	<$100,000	$100k - $500k	$500k - $5m	$5m - $10M	>$10m
Production/Schedule	Up to 3 days	3 days – 1 week	1 wk – 1 month	1 – 6 months	> 6 months
Reputation	Localised temporary impact	Localised, short term impact	Localised, long term impact but manageable	Localised, long term impact with unmanageable outcomes	Long term regional impact
Business Impact	Impact can be absorbed through normal activity	An adverse event which can be absorbed with some management effort	A serious event which requires additional management effort	A critical event which requires extraordinary management effort	Disaster with potential to lead to collapse of the project

Risk Register and Action Plan

Column Key:

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Enter text in this column

Number	Rank	Risk Description (Event and Consequence)	Category	Existing Controls	Risk Severity Before Treatment					Risk Treatment Plan	Ability to Influence	Action Plan Type	Risk Severity After Treatment					Responsible Person	Due Date	Action Progress Status
						Consequence		Likelihood	Risk Level Before Treatment					Consequence		Likelihood	Risk Level After Treatment			
1	0	Opp - Increased reliability for the St. John's and area load by situating inside the 66kV loop.			Opp	Opportunity			Opportunity				Opp	Opportunity			Opportunity			
2	0	Opp - Provides future expansion capability both for Gas Turbine and for distribution			Opp	Opportunity			Opportunity				Opp	Opportunity			Opportunity			
5	0	Opp - no new transmission requirements			Opp	Opportunity			Opportunity				Opp	Opportunity			Opportunity			
17	0	Opp - future prospects to use methane collected at Robin Hood Bay			Opp	Opportunity			Opportunity				Opp	Opportunity			Opportunity			
24	0	Opp - locating near the dump leads to cogen opportunity			Opp	Opportunity			Opportunity				Opp	Opportunity			Opportunity			
8	1	Acquisition of land process is delayed leading to delay in project schedule.		Right to expropriate land may be available.	4	Major	C	Moderate	Extreme	1. Do a title search for proposed locations. 2. Siting study to determine optimal locations for new installation 3. Develop communication plan to highlight opportunities to city. 4. Engage Newfoundland Power in comm plan.		Reduce likelihood	4	Major	D	Unlikely	High	1. H.R. 2. H.R. 3. H.R. 4. H.R.		
6	2	EA release does not get approved leading to unsuitable installation at 74L		Established process used. Experience going through EA process. Alternatives are proposed.	4	Major	D	Unlikely	High	Develop communication plan/strategy to identify how concerns can be mitigated.		Accept	4	Major	D	Unlikely	High	F.R.		
7	3	EIS or EPR required leads to delay in schedule		Established process used. Experience going through EA process. Alternatives are proposed.	4	Major	D	Unlikely	High	1. Develop communication plan/strategy to identify how concerns can be mitigated. 2. Early submission to get early response.		Reduce consequence	3	Moderate	D	Unlikely	Moderate	F.R.		
11	4	Supplier delivery (CT, Transformer) is longer than scheduled leading to delay		Preferred supplier relationships for transformer and gas turbine.	4	Major	D	Unlikely	High	Buy used/surplus equipment. Buy a spot in the assembly line. Tender prior to PUB approval and in parallel with siting study.		Accept	4	Major	D	Unlikely	High	H.R.		
13	5	Contamination is discovered when in construction leads to delay in schedule		None.	4	Major	D	Unlikely	High	Test sites for contamination.		Reduce consequence	4	Major	D	Unlikely	High	H.R.		
14	6	PUB is not aware of this project leading to reputation impact		None	4	Major	D	Unlikely	High	Inform PUB and provide rationale		Reduce consequence	3	Moderate	D	Unlikely	Moderate	J.M.		
15	7	If Lower Churchill does not proceed, this project is not the lowest cost option leading to reputation impact with PUB		none	4	Major	D	Unlikely	High	Inform PUB and provide rationale		Reduce consequence	3	Moderate	D	Unlikely	Moderate	J.M.		
38	8	Unknown environmental risks lead to suspension of operations.		EA process.	4	Major	D	Unlikely	High	Investigate larger footprint property.		Reduce likelihood	4	Major	E	Rare	High	H.R.		
16	9	groundwater contamination during operation		Standard process in place to minimize this risk through design and maintenance	4	Major	E	Rare	High	Design containment to minimize risk		Reduce consequence	3	Moderate	E	Rare	Moderate	H.R.		
18	10	PUB approval is delayed leading to reputational impact due to proceeding prior to approval.		Organization in place to work with the PUB through the approval process. Prepared to proceed with alternate approval.	3	Moderate	B	Likely	High	Seek PUB approval and provide rationale		Accept	3	Moderate	B	Likely	High	J.M.		
19	11	Increased tanker traffic leads to safety incident		none	3	Moderate	C	Moderate	High	Adjust delivery to off peak schedule. Prepare communications/emergency preparedness.		Reduce likelihood	3	Moderate	C	Moderate	High	H.I.		
21	12	Project resource (people) unavailability leads to delay in project schedule		Resource planning. Existing agreements in place to leverage contract engagements.	3	Moderate	C	Moderate	High	Firm up the plan to get resources for this work and take action on getting the resources.		Reduce likelihood and consequence	2	Minor	D	Unlikely	Low	H.R.		
22	13	Increased tanker delivery leads to environmental incident		Contract require response capability.	3	Moderate	C	Moderate	High	Adjust delivery to off peak schedule. Prepare communications/emergency preparedness.		Reduce likelihood	3	Moderate	C	Moderate	High	H.I.		
28	14	Unforeseen costs as a result of new installation lead to budget exceedance			3	Moderate	C	Moderate	High	1. Use a formal estimating process and review process to appropriately apply sufficient contingency based on uncertainty of site. 2. Survey proposed site to reduce unknowns.		Reduce likelihood and consequence	2	Minor	D	Unlikely	Low	1. H.R. 2. H.R.		
10	15	EA process leads to a public hearing which negatively impacts reputation		Standard process to minimize public concerns through the EA process.	3	Moderate	D	Unlikely	Moderate				3	Moderate	D	Unlikely	Moderate			
12	16	Black start at HRD - transmission must be available to allow this to happen - could result in inability to start HRD leading to production impact		Alternatives - Operating procedure in place. Existing HWD facility still available.	3	Moderate	D	Unlikely	Moderate				3	Moderate	D	Unlikely	Moderate			
27	17	Required to expropriate land to facilitate the new installation leads to reputation issue.		None.	3	Moderate	D	Unlikely	Moderate				3	Moderate	D	Unlikely	Moderate			
29	18	unable to go to synch condense mode without gas turbine running leads to reduced reliability		none.	3	Moderate	D	Unlikely	Moderate				3	Moderate	D	Unlikely	Moderate			
37	19	Airborne contaminants (ocean spray - salt) lead to increased corrosion rates on equipment and reduced reliability leading to supply issues		Experience from HRD. Regular maintenance plan to check state of equipment.	3	Moderate	D	Unlikely	Moderate				3	Moderate	D	Unlikely	Moderate			
40	20	Fuel spill during delivery leads to reputational impact		Response plans for contractor. Internal response plan.	3	Moderate	D	Unlikely	Moderate				3	Moderate	D	Unlikely	Moderate			
4	21	Archaeological and cultural discovery leads to delay in schedule		Archaeological site assessment will be completed as per standard practice.	3	Moderate	E	Rare	Moderate				3	Moderate	E	Rare	Moderate			
3	22	New site with shared operator leads to delayed response time.		None.	2	Minor	C	Moderate	Moderate				2	Minor	C	Moderate	Moderate			
23	23	Recreational impact leads to reputation impact		None.	2	Minor	C	Moderate	Moderate				2	Minor	C	Moderate	Moderate			

Risk Register and Action Plan

Column Key:	
(blue)	Do not enter data - automatically generated field
(light green)	Drop down list, select one item from list
(yellow)	Enter text in this column

Number	Rank	Risk Description (Event and Consequence)	Category	Existing Controls	Risk Severity Before Treatment					Risk Treatment Plan	Ability to Influence	Action Plan Type	Risk Severity After Treatment					Responsible Person	Due Date	Action Progress Status
						Consequence		Likelihood	Risk Level Before Treatment					Consequence		Likelihood	Risk Level After Treatment			
30	24	groundwater contamination during construction		Standard process to ensure that there is an enivronmental response plan in place during construction.	2	Minor	C	Moderate	*Moderate*				2	Minor	C	Moderate	*Moderate*			
39	25	Site services are not available leading to additional costs to the project		None.	2	Minor	C	Moderate	*Moderate*				2	Minor	C	Moderate	*Moderate*			
20	26	Wetland impacts due to new installation lead to budget exceedance		None.	2	Minor	D	Unlikely	*Low*				2	Minor	D	Unlikely	*Low*			
25	27	New installation leads to noise complaints leading to reputational impact		Standard process in place to ensure noise levels meet standards.	2	Minor	D	Unlikely	*Low*				2	Minor	D	Unlikely	*Low*			
26	28	New installation leads to emissions complaints leading to reputational impact		Standard process in place to ensure emissions levels meet standards.	2	Minor	D	Unlikely	*Low*				2	Minor	D	Unlikely	*Low*			
32	29	Additional development to satisfy surrounding landowners leads to budget exceedance		none.	2	Minor	D	Unlikely	*Low*				2	Minor	D	Unlikely	*Low*			
33	30	Unfamiliar equipment is installed leading to delay in commissioning and project schedule		Significant experience in general with gas turbines.	2	Minor	D	Unlikely	*Low*				2	Minor	D	Unlikely	*Low*			
34	31	Noise during construction leads to reputational impact.		none.	2	Minor	D	Unlikely	*Low*				2	Minor	D	Unlikely	*Low*			
9	32	Concerns on electromagnetic field impact leads to public reputation.		Site is low density population.	2	Minor	E	Rare	*Low*				2	Minor	E	Rare	*Low*			
35	33	Increased tanker traffic leads to complaints		None.	2	Minor	E	Rare	*Low*				2	Minor	E	Rare	*Low*			
36	34	Zoning issues lead to delay in schedule		Expropriation available, if necessary.	2	Minor	E	Rare	*Low*				2	Minor	E	Rare	*Low*			

Risk Map
Before Treatment

Likelihood				Consequence: Insignificant 1	Minor 2	Moderate 3	Major 4	Catastrophic 5
Likelihood	A	Almost Certain	0%					
	B	Likely	0%			18		
	C	Moderate	0%		3 23 30 39	19 21 22 28	8	
	D	Unlikely	0%		20 25 26 32 33 34	10 12 27 29 37 40	6 7 11 13 14 15 38	
	E	Rare	0%		9 35 36	4	16	

Risk Map
After Treatment

Likelihood			Consequence: Insignificant 1	Minor 2	Moderate 3	Major 4	Catastrophic 5
Likelihood	A	Almost Certain					
	B	Likely			18		
	C	Moderate		3 23 30 39	19 22		
	D	Unlikely		21 28 20 25 26 32 33 34	7 14 15 10 12 27 29 37 40	8 6 11 13	
	E	Rare		9 35 36	16 4	38	

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CT Addition - 74L
Risk Workshop

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Risk Summary

Sort Sort

Threats

Rank	No.	Description	Before	After
1	8	Acquisition of land process is delayed leading to delay in project schedule.	Extreme	High
2	6	EA release does not get approved leading to unsuitable installation at 74L	High	High
4	11	Supplier delivery (CT, Transformer) is longer than scheduled leading to delay	High	High
5	13	Contamination is discovered when in construction leads to delay in schedule	High	High
8	38	Unknown environmental risks lead to suspension of operations.	High	High
10	18	PUB approval is delayed leading to reputational impact due to proceeding prior to approval.	High	High
11	19	Increased tanker traffic leads to safety incident	High	High
13	22	Increased tanker delivery leads to environmental incident	High	High
3	7	EIS or EPR required leads to delay in schedule	High	Moderate
6	14	PUB is not aware of this project leading to reputation impact	High	Moderate
7	15	If Lower Churchill does not proceed, this project is not the lowest cost option leading to reputation impact with PUB	High	Moderate
9	16	groundwater contamination during operation	High	Moderate
15	10	EA process leads to a public hearing which negatively impacts reputation	Moderate	Moderate
16	12	Black start at HRD - transmission must be available to allow this to happen - could result in inability to start HRD leading to production impact	Moderate	Moderate
17	27	Required to expropriate land to facilitate the new installation leads to reputation issue.	Moderate	Moderate
18	29	unable to go to synch condense mode without gas turbine running leads to reduced reliability	Moderate	Moderate
19	37	Airborne contaminants (ocean spray - salt) lead to increased corrosion rates on equipment and reduced reliability leading to supply issues	Moderate	Moderate
20	40	Fuel spill during delivery leads to reputational impact	Moderate	Moderate
21	4	Archaeological and cultural discovery leads to delay in schedule	Moderate	Moderate
22	3	New site with shared operator leads to delayed response time.	Moderate	Moderate
23	23	Recreational impact leads to reputation impact	Moderate	Moderate
24	30	groundwater contamination during construction	Moderate	Moderate
25	39	Site services are not available leading to additional costs to the project	Moderate	Moderate
12	21	Project resource (people) unavailability leads to delay in project schedule	High	Low
14	28	Unforeseen costs as a result of new installation lead to budget exceedance	High	Low
26	20	Wetland impacts due to new installation lead to budget exceedance	Low	Low
27	25	New installation leads to noise complaints leading to reputational impact	Low	Low
28	26	New installation leads to emissions complaints leading to reputational impact	Low	Low
29	32	Additional development to satisfy surrounding landowners leads to budget exceedance	Low	Low
30	33	Unfamiliar equipment is installed leading to delay in commissioning and project schedule	Low	Low
31	34	Noise during construction leads to reputational impact.	Low	Low
32	9	Concerns on electromagnetic field impact leads to public reputation.	Low	Low
33	35	Increased tanker traffic leads to complaints	Low	Low

Risk Summary

Threats

Rank	No.	Description	Before	After
34	36	Zoning issues lead to delay in schedule	Low	Low

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Client:	**Regulated Operations**
Project:	**CT Addition at HWD**
Title:	**Risk Workshop**
Date:	**8-March-2012**

Facilitator: Stephen Fitzpatrick

Attendees:

Howard Richards
Paul Humphries
Jim Haynes
John MacIsaac
Hughie Ireland
Bob Butler
Frank Ricketts

Context for Risk Workshop:

The purpose of this Risk Workshop is to determine the risks associated with installation of a new Combustion Turbine facility at Hardwoods Terminal Station. The risks will encompass all aspects of the project from safety, social and environmental impacts to cost and schedule. This workshop will also include risks associated with operations as a result of the location and installation provided.

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1 PUB
2 Customers
3 Contractors
4 ECC
5 Operations/Work Execution
6 Project Execution
7 LTAP
8 Technical Services
9 Safety and Health
10 Environmental Services
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12 Nalcor
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14 City of St. John's
15 Town of Paradise
16 Local landowners surrounding facility
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Below are some **suggested** likelihood and consequence scales.
Project teams are advised to review the categories and determine a scale that is relevant to their project; in particular the 'Financial' and 'Production/Schedule' categories should be modified to be specific to each Project. All fields should be reviewed and amended/deleted as required prior to commencing the brainstorming session.

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Rare	Unlikely	Moderate	Likely	Almost Certain
Highly unlikely to occur on this project	Given current practices and procedures, this incident is unlikely to occur on this project	Incident has occurred on a similar project	Incident is likely to occur on this project	Incident is very likely to occur on this project, possibly several times
OR				
5% chance of occuring	20% chance of occuring	50% chance of occuring	80% chance of occuring	95% chance of occuring

	Consequences				
	1 - Insignificant	2 - Minor	3 - Moderate	4 - Major	5 - Catastrophic
Safety and Health	**First Aid Case**	**Minor Injury,** Medical Treatment Case with/or Restricted Work Case.	**Serious injury** or Lost Work Case	**Major or Multiple Injuries** permanent injury or disability	**Single or Multiple Fatalities**
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Production/Schedule	Up to 3 days	3 days – 1 week	1 wk – 1 month	1 – 6 months	> 6 months
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Business Impact	Impact can be absorbed through normal activity	An adverse event which can be absorbed with some management effort	A serious event which requires additional management effort	A critical event which requires extraordinary management effort	Disaster with potential to lead to collapse of the project

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						Consequence		Likelihood	Risk Level Before Treatment					Consequence		Likelihood	Risk Level After Treatment			
22	0	Opp - operator is familiar with existing facility and can quickly come up to speed on the new CT or help to train			Opp	Opportunity			Opportunity				Opp	Opportunity			Opportunity			
23	0	Opp - CT situated within the 66 kV loop leads to easier management of St. John's area			Opp	Opportunity			Opportunity				Opp	Opportunity			Opportunity			
25	0	Opp - no new transmission requirements			Opp	Opportunity			Opportunity				Opp	Opportunity			Opportunity			
1	1	EA release does not get approved leading to unsuitable installation at HWD		Established process used. Experience going through EA process. Alternatives are proposed.	4	Major	B	Likely	Extreme	Develop communication plan/strategy to identify how concerns can be mitigated.		Reduce likelihood	4	Major	C	Moderate	Extreme	F.R.		
2	2	EIS or EPR required leads to delay in schedule		Established process used. Experience going through EA process. Alternatives are proposed.	4	Major	C	Moderate	Extreme	1. Develop communication plan/strategy to identify how concerns can be mitigated. 2. Early submission to get early response.		Reduce consequence	3	Moderate	C	Moderate	High	1. F.R. 2. F.R.		
3	3	Physical space in existing terminal station is insufficient to install new CT		Alternatives are proposed. The facility was originally designed for a second 50MW turbine.	4	Major	C	Moderate	Extreme	1. Assess land availability/plot plan. 2. Look at compact design for new equipment.		Reduce likelihood	3	Moderate	D	Unlikely	Moderate	1. H.R. 2. H.R.		
9	4	Precedent is set with installation of new technology leading to demands to improve existing - cost impact		None	4	Major	C	Moderate	Extreme	Develop commmunication plan/strategy to inform of plans to replace old machine.		Reduce likelihood	4	Major	D	Unlikely	High	H.R.		
21	5	EA process leads to a public hearing which negatively impacts reputation		Standard process to minimize public concerns through the EA process.	4	Major	C	Moderate	Extreme	Develop communication plan/strategy to identify how concerns can be mitigated.		Accept	4	Major	C	Moderate	Extreme	F.R.		
5	6	Supplier delivery (CT, Transformer) is longer than scheduled leading to delay		Preferred supplier relationships for transformer and gas turbine.	4	Major	D	Unlikely	High	Buy used/surplus equipment. Buy a spot in the assembly line. Tender prior to PUB approval and in parallel with siting study.		Accept	4	Major	D	Unlikely	High	H.R.		
15	7	Contamination is discovered when in construction leads to delay in schedule		Site assessments have been done previously at this location.	4	Major	D	Unlikely	High	Test sites for contamination.		Reduce consequence	2	Minor	D	Unlikely	Low	H.R.		
26	8	PUB is not aware of this project leading to reputation impact		None	4	Major	D	Unlikely	High	Inform PUB and provide rationale		Reduce consequence	3	Moderate	D	Unlikely	Moderate	J.M.		
27	9	If Lower Churchill does not proceed, this project is not the lowest cost option leading to reputation impact with PUB		none	4	Major	D	Unlikely	High	Inform PUB and provide rationale		Reduce consequence	3	Moderate	D	Unlikely	Moderate	J.M.		
10	10	Black start at HRD - transmission must be available to allow this to happen - could result in inability to start HRD leading to production impact		Operating procedure in place. 230 kV Transmission lines have been upgraded. Minimal failures. Outage planning to work around potential ice storms. Ensure two of three routes are available.	4	Major	E	Rare	High	Planning and operational studies - simulations.		Accept	4	Major	E	Rare	High	P.H. (B.B.)		
8	11	groundwater contamination during operation		Standard process in place to minimize this risk through design and maintenance	4	Major	E	Rare	High	Design containment to minimize risk		Reduce consequence	3	Moderate	E	Rare	Moderate	H.R.		
30	12	Two turbines in one location - transmission failure leads to reduction in supply. - black start		Transmission redundancy.	4	Major	E	Rare	High	None.		Accept	4	Major	E	Rare	High			
4	13	PUB approval is delayed leading to reputational impact due to proceeding prior to approval.		Organization in place to work with the PUB through the approval process. Prepared to proceed with alternate approval.	3	Moderate	B	Likely	High	Seek PUB approval and provide rationale		Accept	3	Moderate	B	Likely	High	J.M.		
13	14	Increased tanker traffic leads to safety incident		none	3	Moderate	C	Moderate	High	Adjust delivery to off peak schedule. Prepare communications/emergency preparedness.		Reduce likelihood	3	Moderate	D	Unlikely	Moderate	H.I.		
16	15	Damage to existing equipment during construction leads to unplanned outage (buried cable, for example)		Drawings of the site are available, but may not be accurate.	3	Moderate	C	Moderate	High	Survey installation locations for obstacles. Construction planning to minimize impact.		Reduce likelihood	3	Moderate	D	Unlikely	Moderate	H.R.		
29	16	Project resource (people) unavailability leads to delay in project schedule		Resource planning. Existing agreements in place to leverage contract engagements.	3	Moderate	C	Moderate	High	Firm up the plan to get resources for this work and take action on getting the resources.		Reduce likelihood and consequence	2	Minor	D	Unlikely	Low	H.R.		
33	17	Increased tanker delivery leads to environmental incident		Contract require response capability.	3	Moderate	C	Moderate	High	Adjust delivery to off peak schedule. Prepare communications/emergency preparedness.		Reduce likelihood	3	Moderate	D	Unlikely	Moderate	H.I.		
18	18	Construction leads to increased planned outages leading to reduction in reliability		Permits required - outage management system	2	Minor	B	Likely	High	1. On-site assessment to determine which outages are required. 2. Construction plan review with operations to optimize outage time.		Reduce likelihood	2	Minor	C	Moderate	Moderate	1. B.B. 2. H.R.		
20	19	Congested area leads to additional cost to do maintenance in the facility		Standard design practices.	2	Minor	B	Likely	High	Review proposed layout with maintenance to ensure that sufficient space is available for proper maintenance.		Reduce likelihood	2	Minor	D	Unlikely	Low	H.R.		
6	20	New installation leads to noise complaints leading to reputational impact		Standard process in place to ensure noise levels meet standards.	3	Moderate	D	Unlikely	Moderate				3	Moderate	D	Unlikely	Moderate			
7	21	New installation leads to emissions complaints leading to reputational impact		Standard process in place to ensure emissions levels meet standards.	3	Moderate	D	Unlikely	Moderate				3	Moderate	D	Unlikely	Moderate			
14	22	Shared equipment between CTs leads to common mode unavailability - production loss		Reliability assessments are regularly undertaken. Condition assessments and ongoing maintenance plans.	3	Moderate	D	Unlikely	Moderate				3	Moderate	D	Unlikely	Moderate			
19	23	Maintenance at this site will be done in a tighter area leading to safety incident potential		A safety management plan is required for construction on site.	3	Moderate	D	Unlikely	Moderate				3	Moderate	D	Unlikely	Moderate			
24	24	unable to go to synch condense mode without gas turbine running leads to reduced reliability		none.	3	Moderate	D	Unlikely	Moderate				3	Moderate	D	Unlikely	Moderate			

Risk Register and Action Plan

Column Key:	
	Do not enter data - automatically generated field
	Drop down list, select one item from list
	Enter text in this column

Number	Rank	Risk Description (Event and Consequence)	Category	Existing Controls	Risk Severity Before Treatment					Risk Treatment Plan	Ability to Influence	Action Plan Type	Risk Severity After Treatment					Responsible Person	Due Date	Action Progress Status
						Consequence		Likelihood	Risk Level Before Treatment					Consequence		Likelihood	Risk Level After Treatment			
32	25	groundwater contamination during construction		Standard process to ensure that there is an enivronmental response plan in place during construction.	2	Minor	C	Moderate	*Moderate*				2	Minor	C	Moderate	*Moderate*			
12	26	Additional tankage required leads to complaints		Existing approval processes will be followed.	2	Minor	D	Unlikely	*Low*				2	Minor	D	Unlikely	*Low*			
17	27	Additional development to satisfy surrounding landowners leads to budget exceedance		none.	2	Minor	D	Unlikely	*Low*				2	Minor	D	Unlikely	*Low*			
28	28	Unfamiliar equipment is installed leading to delay in commissioning and project schedule		Significant experience in general with gas turbines.	2	Minor	D	Unlikely	*Low*				2	Minor	D	Unlikely	*Low*			
31	29	Noise during construction leads to reputational impact.		none.	2	Minor	D	Unlikely	*Low*				2	Minor	D	Unlikely	*Low*			
11	30	Increased tanker traffic leads to complaints		None.	2	Minor	E	Rare	*Low*				2	Minor	E	Rare	*Low*			

Risk Map
Before Treatment

Likelihood				Consequence: Insignificant 1	Minor 2	Moderate 3	Major 4	Catastrophic 5
Likelihood	A	Almost Certain	0%					
	B	Likely	0%		18 20	4	1	
	C	Moderate	0%		32	13 16 29 33	2 3 9 21	
	D	Unlikely	0%		12 17 28 31	6 7 14 19 24	5 15 26 27	
	E	Rare	0%		11		10 8 30	

Risk Map
After Treatment

Likelihood			Consequence: Insignificant 1	Minor 2	Moderate 3	Major 4	Catastrophic 5
Likelihood	A	Almost Certain					
	B	Likely			4		
	C	Moderate		18 32	2	1 21	
	D	Unlikely		15 29 20 12 17 28 31	3 26 27 13 16 33 6 7 14 19 24	9 5	
	E	Rare		11	8	10 30	

Risk Summary

Sort Sort

Threats

Rank	No.	Description	Before	After
1	1	EA release does not get approved leading to unsuitable installation at HWD	Extreme	Extreme
5	21	EA process leads to a public hearing which negatively impacts reputation	Extreme	Extreme
2	2	EIS or EPR required leads to delay in schedule	Extreme	High
4	9	Precedent is set with installation of new technology leading to demands to improve existing - cost impact	Extreme	High
6	5	Supplier delivery (CT, Transformer) is longer than scheduled leading to delay	High	High
10	10	Black start at HRD - transmission must be available to allow this to happen - could result in inability to start HRD leading to production impact	High	High
12	30	Two turbines in one location - transmission failure leads to reduction in supply. - black start	High	High
13	4	PUB approval is delayed leading to reputational impact due to proceeding prior to approval.	High	High
3	3	Physical space in existing terminal station is insufficient to install new CT	Extreme	Moderate
8	26	PUB is not aware of this project leading to reputation impact	High	Moderate
9	27	If Lower Churchill does not proceed, this project is not the lowest cost option leading to reputation impact with PUB	High	Moderate
11	8	groundwater contamination during operation	High	Moderate
14	13	Increased tanker traffic leads to safety incident	High	Moderate
15	16	Damage to existing equipment during construction leads to unplanned outage (buried cable, for example)	High	Moderate
17	33	Increased tanker delivery leads to environmental incident	High	Moderate
18	18	Construction leads to increased planned outages leading to reduction in reliability	High	Moderate
20	6	New installation leads to noise complaints leading to reputational impact	Moderate	Moderate
21	7	New installation leads to emissions complaints leading to reputational impact	Moderate	Moderate
22	14	Shared equipment between CTs leads to common mode unavailability - production loss	Moderate	Moderate
23	19	Maintenance at this site will be done in a tighter area leading to safety incident potential	Moderate	Moderate
24	24	unable to go to synch condense mode without gas turbine running leads to reduced reliability	Moderate	Moderate
25	32	groundwater contamination during construction	Moderate	Moderate
7	15	Contamination is discovered when in construction leads to delay in schedule	High	Low
16	29	Project resource (people) unavailability leads to delay in project schedule	High	Low
19	20	Congested area leads to additional cost to do maintenance in the facility	High	Low
26	12	Additional tankage required leads to complaints	Low	Low
27	17	Additional development to satisfy surrounding landowners leads to budget exceedance	Low	Low
28	28	Unfamiliar equipment is installed leading to delay in commissioning and project schedule	Low	Low
29	31	Noise during construction leads to reputational impact.	Low	Low

WorleyParsons
resources & energy

Regulated Operations
CT Addition - HWD
Risk Workshop

nalcor energy

Risk Summary

Sort Sort

Threats

Rank	No.	Description	Before		After
30	11	Increased tanker traffic leads to complaints	Low		Low

Index

Client:	**Regulated Operations**
Project:	**CT Addition - HRD**
Title:	**Risk Workshop**
Date:	**8-March-2012**

Facilitator: Stephen Fitzpatrick

Attendees:

Howard Richards
Terry LeDrew
Jim Haynes
John MacIsaac
Hughie Ireland
Bob Butler
Paul Humphries
Frank Ricketts

Context for Risk Workshop:

The purpose of this Risk Workshop is to determine the risks associated with installation of a new Combustion Turbine facility at Holyrood Generating Station. The risks will encompass all aspects of the project from safety, social and environmental impacts to cost and schedule. This workshop will also include risks associated with operations as a result of the location and installation provided.

Stakeholders:

1 PUB
2 Customers
3 Contractors
4 ECC
5 Operations/Work Execution
6 Project Execution
7 LTAP
8 Technical Services
9 Safety and Health
10 Environmental Services
11 Newfoundland Power
12 Nalcor
13 Lower Churchill Project
14 Employees at Holyrood GS
15 Community Liaison Committee
16 Local landowners surrounding facility
17 Provincial government
18 Holyrood Generating Station
19 Town of Holyrood
20 Town of CBS

Key Success Factors:

1 Zero Harm
2 Project Completion by the peak of 2014/2015
3 Minimal environmental impact.
4 Reliable operation after project complete
5 Project completed within budget
6 Stakeholders are regularly informed on status.
7 Provide black start capability to HRD
8 Meet system planning requirements to meet demand until Lower Churchill on line - 2017
9 Decision to proceed by March 2012
10 Installation meets standard design criteria.

Below are some **suggested** likelihood and consequence scales.
Project teams are advised to review the categories and determine a scale that is relevant to their project; in particular the 'Financial' and 'Production/Schedule' categories should be modified to be specific to each Project. All fields should be reviewed and amended/deleted as required prior to commencing the brainstorming session.

Likelihood Category				
E	**D**	**C**	**B**	**A**
Rare	**Unlikely**	**Moderate**	**Likely**	**Almost Certain**
Highly unlikely to occur on this project	Given current practices and procedures, this incident is unlikely to occur on this project	Incident has occurred on a similar project	Incident is likely to occur on this project	Incident is very likely to occur on this project, possibly several times
OR				
5% chance of occuring	20% chance of occuring	50% chance of occuring	80% chance of occuring	95% chance of occuring

	Consequences				
	1 - Insignificant	**2 - Minor**	**3 - Moderate**	**4 - Major**	**5 - Catastrophic**
Safety and Health	**First Aid Case**	**Minor Injury,** Medical Treatment Case with/or Restricted Work Case.	**Serious injury** or Lost Work Case	**Major or Multiple Injuries** permanent injury or disability	**Single or Multiple Fatalities**
Environment	**No impact** on baseline environment. Localized to point source. No recovery required	**Localized** within site boundaries. Recovery measurable within 1 month of impact	**Moderate** harm with possible wider effect. Recovery in 1 year	**Significant** harm with local effect. Recovery longer than 1 year.	**Significant** harm with widespread effect. Recovery longer than 1 year. Limited prospect of full recovery
Financial	<$100,000	$100k - $500k	$500k - $5m	$5m - $10M	>$10m
Production/Schedule	Up to 3 days	3 days – 1 week	1 wk – 1 month	1 – 6 months	> 6 months
Reputation	Localised temporary impact	Localised, short term impact	Localised, long term impact but manageable	Localised, long term impact with unmanageable outcomes	Long term regional impact
Business Impact	Impact can be absorbed through normal activity	An adverse event which can be absorbed with some management effort	A serious event which requires additional management effort	A critical event which requires extraordinary management effort	Disaster with potential to lead to collapse of the project

Risk Register and Action Plan

Column Key:	
(blue)	Do not enter data - automatically generated field
(green)	Drop down list, select one item from list
(yellow)	Enter text in this column

Number	Rank	Risk Description (Event and Consequence)	Category	Existing Controls	Risk Severity Before Treatment					Risk Treatment Plan	Ability to Influence	Action Plan Type	Risk Severity After Treatment					Responsible Person	Due Date	Action Progress Status
						Consequence		Likelihood	Risk Level Before Treatment					Consequence		Likelihood	Risk Level After Treatment			
1	0	Opp - operator is familiar with existing facility and can quickly come up to speed on the new CT or help to train			Opp	Opportunity			*Opportunity*				Opp	Opportunity			*Opportunity*			
2	0	Organization that focused on environmental and operational issues at Holyrood - more directed concerns as a result of installation.			Opp	Opportunity			*Opportunity*				Opp	Opportunity			*Opportunity*			
3	0	Opp - no new transmission requirements			Opp	Opportunity			*Opportunity*				Opp	Opportunity			*Opportunity*			
7	0	ECC control in HRD - local staff to support installation			Opp	Opportunity			*Opportunity*				Opp	Opportunity			*Opportunity*			
10	0	Opp - black start on site and does not require significant transmission path			Opp	Opportunity			*Opportunity*				Opp	Opportunity			*Opportunity*			
21	0	Opp - can build installation and tie in without requirement for major outage.			Opp	Opportunity			*Opportunity*				Opp	Opportunity			*Opportunity*			
24	0	Opp - Retain some key employees as a result of 50MW installation at HRD			Opp	Opportunity			*Opportunity*				Opp	Opportunity			*Opportunity*			
31	0	Opp - Existing air monitoring equipment and CEM at this site			Opp	Opportunity			*Opportunity*				Opp	Opportunity			*Opportunity*			
34	0	Opp - Infrastructure available at HRD to support new CT. Fire suppression, utilities, security, etc…			Opp	Opportunity			*Opportunity*				Opp	Opportunity			*Opportunity*			
4	1	EA release does not get approved leading to unsuitable installation at HRD		Established process used. Experience going through EA process. Alternatives are proposed.	4	Major	D	Unlikely	*High*	Discuss the new installation with the community liaison committee - communication plan.		Reduce likelihood	4	Major	E	Rare	*High*	Terry L.		
5	2	EIS or EPR required leads to delay in schedule	Project Management	Established process used. Experience going through EA process. Alternatives are proposed.	4	Major	D	Unlikely	*High*	1. Discuss the new installation with the community liaison committee - communication plan. 2. Submit the paperwork as early as possible.		Reduce likelihood	4	Major	E	Rare	*High*	1. T.L. 2. F.R.		
8	3	EA process leads to a public hearing which negatively impacts reputation	Community	Standard process to minimize public concerns through the EA process.	4	Major	D	Unlikely	*High*	Discuss the new installation with the community liaison committee - communication plan.		Reduce likelihood	4	Major	E	Rare	*High*	T.L.		
9	4	Supplier delivery (CT, Transformer) is longer than scheduled leading to delay	Procurement/Contractors/Suppliers	Preferred supplier relationships for transformer and gas turbine.	4	Major	D	Unlikely	*High*	Buy used/surplus equipment. Buy a spot in the assembly line. Tender prior to PUB approval and in parallel with siting study.		Accept	4	Major	D	Unlikely	*High*	H.R.		
11	5	Contamination is discovered when in construction leads to delay in schedule	Construction	None.	4	Major	D	Unlikely	*High*	Test possible sites for installation to determine level of contamination.		Reduce consequence	2	Minor	D	Unlikely	*Low*	F.R.		
12	6	PUB is not aware of this project leading to reputation impact	Government / Regulatory	None	4	Major	D	Unlikely	*High*	Inform the PUB and provide rationale		Reduce consequence	3	Moderate	D	Unlikely	*Moderate*	J.M.		
13	7	If Lower Churchill does not proceed, this project is not the lowest cost option leading to reputation impact with PUB		none	4	Major	D	Unlikely	*High*	Inform the PUB and provide rationale		Reduce consequence	3	Moderate	D	Unlikely	*Moderate*	J.M.		
14	8	groundwater contamination during operation		Standard process in place to minimize this risk through design and maintenance	4	Major	E	Rare	*High*	Design containment to minimize the risk.		Reduce consequence	3	Moderate	E	Rare	*Moderate*	H.R.		
6	9	CT not situated in the 66kV loop leading to greater and different unserved load and advanced transformer investment in St. John's area.		Planning reliability criteria.	3	Moderate	B	Likely	*High*	Advance transformer investment.		Reduce consequence	2	Minor	B	Likely	*High*	P.H.		
16	10	PUB approval is delayed leading to reputational impact due to proceeding prior to approval.		Organization in place to work with the PUB through the approval process. Prepared to proceed with alternate approval.	3	Moderate	B	Likely	*High*	Seek PUB approval and provide rationale		Reduce consequence	3	Moderate	B	Likely	*High*	J.M.		
17	11	Increased tanker traffic leads to safety incident		none	3	Moderate	C	Moderate	*High*	Adjust delivery schedule to off peak times. Source fuel from local provider.		Reduce likelihood	3	Moderate	D	Unlikely	*Moderate*	T.L.		
19	12	Project resource (people) unavailability leads to delay in project schedule		Resource planning. Existing agreements in place to leverage contract engagements.	3	Moderate	C	Moderate	*High*	Firm up the plan to get resources for this work and take action on getting the resources.		Reduce likelihood and consequence	2	Minor	D	Unlikely	*Low*	H.R.		
29	13	Airborne contaminants (ocean spray - salt) lead to increased corrosion rates on equipment and reduced reliability leading to supply issues			3	Moderate	C	Moderate	*High*	Design to incorporate addressing this issue. Building is an option.		Reduce likelihood	3	Moderate	E	Rare	*Moderate*	H.R.		
22	14	Installation of a new CT at Holyrood contradicts previous message to public leading to reputation impact.		CLC relationship	2	Minor	B	Likely	*High*	Discuss the new installation with the community liaison committee - communication plan.		Reduce likelihood and consequence	1	Insignificant	D	Unlikely	*Low*			
20	15	Increased tanker delivery leads to environmental incident		Contract require response capability. Environmental response is readily available at HRD.	3	Moderate	D	Unlikely	*Moderate*				3	Moderate	D	Unlikely	*Moderate*			
15	16	Emissions modelling leads to potential environmental mitigation requirements leading to additional cost		None.	3	Moderate	D	Unlikely	*Moderate*				3	Moderate	D	Unlikely	*Moderate*			
23	17	New installation leads to emissions complaints leading to reputational impact		Standard process in place to ensure emissions levels meet standards.	3	Moderate	D	Unlikely	*Moderate*				3	Moderate	D	Unlikely	*Moderate*			
26	18	unable to go to synch condense mode without gas turbine running leads to reduced reliability		none.	3	Moderate	D	Unlikely	*Moderate*				3	Moderate	D	Unlikely	*Moderate*			
27	19	groundwater contamination during construction		Standard process to ensure that there is an environmental response plan in place during construction.	2	Minor	C	Moderate	*Moderate*				2	Minor	C	Moderate	*Moderate*			
18	20	Damage to existing equipment during construction leads to unplanned outage (buried cable, for example)		Drawings of the site are available, but may not be accurate.	2	Minor	D	Unlikely	*Low*				2	Minor	D	Unlikely	*Low*			
28	21	Additional tankage required leads to complaints		Existing approval processes will be followed.	2	Minor	D	Unlikely	*Low*				2	Minor	D	Unlikely	*Low*			

Risk Register and Action Plan

Column Key:	
(blue)	Do not enter data - automatically generated field
(light green)	Drop down list, select one item from list
(yellow)	Enter text in this column

Number	Rank	Risk Description (Event and Consequence)	Category	Existing Controls	Risk Severity Before Treatment					Risk Treatment Plan	Ability to Influence	Action Plan Type	Risk Severity After Treatment					Responsible Person	Due Date	Action Progress Status
						Consequence		Likelihood	Risk Level Before Treatment					Consequence		Likelihood	Risk Level After Treatment			
30	22	Unfamiliar equipment is installed leading to delay in commissioning and project schedule		Significant experience in general with gas turbines.	2	Minor	D	Unlikely	Low				2	Minor	D	Unlikely	Low			
33	23	Construction noise leads to complaints		Low compared to plant noise	2	Minor	D	Unlikely	Low				2	Minor	D	Unlikely	Low			
25	24	Security and safety incident as a result of increased activity		Existing safety and security process for this site.	2	Minor	E	Rare	Low				2	Minor	E	Rare	Low			
32	25	Increased tanker traffic leads to complaints		None.	2	Minor	E	Rare	Low				2	Minor	E	Rare	Low			

Risk Map
Before Treatment

Likelihood				Consequence: Insignificant 1	Minor 2	Moderate 3	Major 4	Catastrophic 5
	A	Almost Certain	0%					
	B	Likely	0%		22	6 16		
	C	Moderate	0%		27	17 19 29		
	D	Unlikely	0%		18 28 30 33	20 15 23 26	4 5 8 9 11 12 13	
	E	Rare	0%		25 32		14	

Risk Map
After Treatment

Likelihood			Consequence: Insignificant 1	Minor 2	Moderate 3	Major 4	Catastrophic 5
	A	Almost Certain					
	B	Likely		6	16		
	C	Moderate		27			
	D	Unlikely	22	11 19 18 28 30 33	12 13 17 20 15 23 26	9	
	E	Rare		25 32	14 29	4 5 8	

Risk Summary

Sort Sort

Threats

Rank	No.	Description	Before	After
1	4	EA release does not get approved leading to unsuitable installation at HRD	High	High
2	5	EIS or EPR required leads to delay in schedule	High	High
3	8	EA process leads to a public hearing which negatively impacts reputation	High	High
4	9	Supplier delivery (CT, Transformer) is longer than scheduled leading to delay	High	High
9	6	CT not situated in the 66kV loop leading to greater and different unserved load and advanced transformer investment in St. John's area.	High	High
10	16	PUB approval is delayed leading to reputational impact due to proceeding prior to approval.	High	High
6	12	PUB is not aware of this project leading to reputation impact	High	Moderate
7	13	If Lower Churchill does not proceed, this project is not the lowest cost option leading to reputation impact with PUB	High	Moderate
8	14	groundwater contamination during operation	High	Moderate
11	17	Increased tanker traffic leads to safety incident	High	Moderate
13	29	Airborne contaminants (ocean spray - salt) lead to increased corrosion rates on equipment and reduced reliability leading to supply issues	High	Moderate
15	20	Increased tanker delivery leads to environmental incident	Moderate	Moderate
16	15	Emissions modelling leads to potential environmental mitigation requirements leading to additional cost	Moderate	Moderate
17	23	New installation leads to emissions complaints leading to reputational impact	Moderate	Moderate
18	26	unable to go to synch condense mode without gas turbine running leads to reduced reliability	Moderate	Moderate
19	27	groundwater contamination during construction	Moderate	Moderate
5	11	Contamination is discovered when in construction leads to delay in schedule	High	Low
12	19	Project resource (people) unavailability leads to delay in project schedule	High	Low
14	22	Installation of a new CT at Holyrood contradicts previous message to public leading to reputation impact.	High	Low
20	18	Damage to existing equipment during construction leads to unplanned outage (buried cable, for example)	Low	Low
21	28	Additional tankage required leads to complaints	Low	Low
22	30	Unfamiliar equipment is installed leading to delay in commissioning and project schedule	Low	Low
23	33	Construction noise leads to complaints	Low	Low
24	25	Security and safety incident as a result of increased activity	Low	Low
25	32	Increased tanker traffic leads to complaints	Low	Low

APPENDIX G

AMEC Report - Existing HRD GT

19 December 2011

Mr. Todd Collins, P. Eng.
Mechanical Design Engineer, Engineering Services
NALCOR Energy
Hydro Place, 500 Columbus Drive
PO Box 12400
St John's, NL, Canada
A1B 4K7

Dear Todd,

Holyrood Thermal Generating Station (Holyrood) Gas Turbine Condition Assessment & Options Study – Final Report

As per our Agreement, we have completed the Holyrood Thermal Generating Station Gas Turbine Condition Assessment. I trust that the report satisfies your needs.

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

Yours truly,

Blair Seckington
Director, Power Technology
Direct Tel.: 905-403-5004
Direct Fax: 905-829-1707
E-mail: blair.seckington@amec.com

BRS/brs
c: C. Woodall
c. R. Livet
c: A. Duplessis

Holyrood Thermal Generating Station

Gas Turbine Condition Assessment & Options Study

December 19, 2011

Holyrood Thermal Generating Station
Gas Turbine Condition Assessment & Options Study

Blair Seckington
Prepared by: Date

Ian Leach
Checked by: Date

Bob Livet
Approved by: Date

Rev.	Description	Prepared By:	Checked:	Approved	Date
A	Draft Report	Blair Seckington			
0	Final Report	Blair Seckington	Ian Leach		30 Aug 2011
1	Final Report	Blair Seckington		Bob Livet	19 Dec 2011

IMPORTANT NOTICE

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HOLYROOD THERMAL GENERATING STATION
GAS TURBINE CONDITION ASSESSMENT & OPTIONS STUDY

EXECUTIVE SUMMARY

The Holyrood gas turbine generator is a nominally 13.5 MW packaged generating unit system. It serves as a black start unit for the station and is occasionally used for system support. Due to the critical nature of the role that the Holyrood GT plays, it must operate with a high degree of operational reliability.

The gas turbine went in service at Holyrood in 1986. As of December 2010, the unit had a total of approximately 4717 operating hours, +386,000 idle hours, and 2548 starts. Due to the age of the gas turbine and balance of plant, the large number of idle hours, and its exposure to a marine environment, it was necessary to perform a comprehensive condition assessment and life extension study. In general, the unit and balance of plant equipment requires refurbishment or replacement work to continue operating with a high degree of reliability to its required end of life of 2020. The study will identify the measures that need to be taken to ensure reliable operation of the gas turbine (GT) and balance of plant. AMEC Americas Limited (AMEC) was contracted by NL Hydro to conduct a Condition Assessment and Refurbishment/Replacement Study for the Holyrood BlackStart Gas Turbine Generator and balance of plant equipment.

The scope of work consists of an engineering study that will assess the condition of the Holyrood Thermal Generating Station (HTGS) gas turbine and balance of plant and make recommendations for work including cost estimates that will be required to extend its useful life to 2020 with the same high degree of reliability as that experienced in the past. The engineering study will include a Level 2 study as per the guidelines of the Electrical Power Research Institute (EPRI). During the 1970's and 1980's, EPRI developed a three level methodology for performing condition assessment and life extension studies within the utilities industry in which the level of sophistication and detail increases progressively through Level I, Level II, and Level III studies. AMEC shall apply this process to the gas turbine generator and balance of plant equipment.

Part A of the study is primarily a detailed condition assessment and refurbishment study of the existing gas turbine plant located at HTGS with recommendations and cost estimates to extend the life of the gas turbine plant as a highly reliable operation to the year 2020.

Part B of the study examines the replacement of the existing gas turbine plant with a new or good used mobile generating plant considering either:

a) A GT plant consisting of two 5 MW mobile/transportable units.

b) A diesel generating plant consisting of five 2 MW diesel units.

As a result of the assessment, AMEC makes the following conclusions and recommendations:

ASSESSMENT BASIS

1. A black-start installation of ten (10) megawatts (MW) is required at the Holyrood Thermal Generating Station site to ensure the capability of the Holyrood units to quickly return to service in the event of a major system failure.

2. The black-start capability must be maintained during any refurbishment or replacement period. This particularly impacts the existing GTG refurbishment option since refurbishment of the existing unit may take an outage of months during which another standby generation unit may be needed and its costs borne by the project. For the existing unit, the lease cost can vary from about $170,000 for the

lease of a reconditioned gas generator and power turbine to swap into the existing unit to about $4.7 million for the lease of a complete 10 MW portable/transportable installation including all associated balance of plant systems and installation.

3. Each of the options has a "terminal value" at the end of the 2020 period. The amount is a function of both the age and condition and market value of the units at that time, and/or of its internal value for redeployment for other uses within Hydro post 2020 (i.e. regional distribution line outage/maintenance support). Potential short term alternative uses prior to 2020 may also have value, but were not assessed.

TERMINAL VALUES IN 2020

Option	Purchased Equipment Cost M$	System Terminal Value in 2020 M$	Comment
Option 0 - Refurbished Existing Unit	$3.0	$0	Terminal value covers cost for demolition
Option 1 - New 2 x 5 MW GT	$10.9	$7.0	Low use, essentially new condition.
Option 1A - Nearly New 2 x 5 MW GT	$9.2	$4.0	Lower percent recovery than new given prior use.
Option 2 - New 5 x 2 MW Diesel Genset	$8.6	$5.0	Lower market value – more available.
Option 2A - Nearly New 5 x 2 MW Diesel Genset	$7.5	$3.0	Lower percent recovery than new given prior use.

4. The system failure cost" of each of the options during the period to the end of 2020. This is a function of the expected or predicted difference in reliability between the options and the cost per hour of electric system black-out/disruption. The situation assumed to occur would be similar to the 1986 island blackout which lasted about 30 hours

ECONOMIC VALUES – FAILURE TO OPERATE ASSUMPTIONS

Failure To Operate		% Probability once over 2013-2020	Value of Hr Shutdown	# Hrs Per Shutdown	Probable $/Incident
		% (A)	MM$/Hr (B)	Hrs (C)	MM$ (D) = AxBxC
Option 0	Refurbished Unit	10%	$5	20	$10
Option1 & 1A	New/Used 2 x 5 MW GT	0%	$5	20	$0
Option 2 & 2A	New/Used 5x2 MW Diesel	4%	$5	20	$4

Notes:
Value/ Hr Shutdown = $5 MM (Impact to Newfoundland Economy)
Probability risk is relative to the new 2 x 5MW GT option
One occurrence assumed nominally in 2016
Probable $/incident increases proportional to (A), (B), or (C)

CONCLUSIONS

Existing Gas Turbine Generator Unit

1. The existing GT generator should not be operated (started, operated, shutdown) except in an emergency situation, and in such an emergency its operation should be observe remotely to ensure personnel safety.
   i) Fire from lube oil system gearbox seals remains a possible safety issue.
   ii) Catastrophic failure of the power turbine disk is a possibility due to corrosion and high stress that may be present at blade roots and attachments
2. The existing GT generator requires extensive overhaul and repair work:
   i) Power turbine disk may require replacement (9 month manufacturing lead time)
   ii) One or more power turbine blades may require replacement or significant repair
   iii) Gas generator blading requires cleaning and recoating
   iv) Inlet filter media requires replacement and inlet duct requires refurbishment (including cooling air duct to power turbine disk)
   v) Exhaust stack requires replacement or extensive repairs
   vi) Gearbox lube oil system requires modification and refurbishment
      a. Seals require replacement/modification
      b. Venting system modifications required to reduce lube oil pressure buildup
      c. Lube oil pump system requires upgrade for start-ups.
      d. Lube oil cooling fan is experiencing some leaks and snow and ice and water build-ups in its containment can cause start-issues
   vii) Gearbox bearings likely worn and need refurbishment or replacement and/or unit re-alignment
   viii) Unit generator requires significant testing and possibly rewind
   ix) Unit generator exciter needs refurbishment and likely replacement
3. GT electrical and controls system has elements that are not in compliance with current standards and/or are obsolete and hence necessitates replacement:
   i) Unit AVR
   ii) Unit MCC's
4. The GT and generator enclosure rooms require modification to their fire detection and suppression systems to provide better coverage, as evidenced by the failure of the system to initially detect or suppress the gearbox lube oil fire in 2010.
5. GT fuel oil receiving, forwarding, and delivery system are in operable condition, but climatic conditions (icing, snow-buildup, water build-ups from rain, rusting from salty ambient air) result in significant periods where starts may fail or be significantly delayed. The GT generator building is in generally good condition, except for:
   i) Major leaks in and around the GT exhaust stack which are impacting the gas turbine power turbine volute and back end blades;
   ii) Minor leaks at generator ventilation stack; and
   iii) Minor air leaks as a result of minor siding holes (corrosion) which require repair/ refurbishment
6. The electrical services room require expansion to allow for new electrical systems and current systems to be in compliance with current standards (i.e. space, separation distance for arc flash).

7. The earliest in-service dates for refurbishing the existing unit and returning it to service:
    a. Without back-up during the existing unit outage, but restricting the outage to lower risk, late spring to early fall periods is October 2013, with a roughly six month outage.
    b. With a nearly new 2 x 5 MW GT leased unit required during an existing unit outage is July 2013 with the existing unit on outage about five months.
    c. With shorter duration engineering and procurement times for BOP, fuel system and electrical systems, the in-service can theoretically be advance two to three months, but outage scheduling would likely mitigate this.

    Note: Using leased parts during outage, or procuring used parts and refurbishing them, has no significant positive impact.
8. The capital cost for refurbishing the existing unit is between $4.5 and $5 million, depending on the amount of additional work found during refurbishment. If leasing a replacement 2 x 5 MW unit is required to avoid any outage, then the total capital cost would be between $9.5 and $10.0 million, depending on the market price and availability of portable/mobile equipment. There is some opportunity to slightly reduce costs if used parts for the unit, and in particular the power turbine disk, are available.

New and Nearly-New 2 x 5MW Portable/Transportable Gas Turbine Generator Units

1. The two 5 MW transportable gas turbine units option is consistent with the requirements for black start power, the need to start a 3 MW power block (one boiler feed pump motor), and simplicity of managing the number of black start units in parallel.
2. The space requirements for the two 5 MW transportable gas turbine units (2 trailers each plus a common electrical building) cannot be accommodated in the existing GT area.
3. Space and civil requirements support the use of the existing well graded area behind the old security building as the best location.
4. Two new 5 MW transportable gas turbine units could be readily purchased, with a manufacturing time of about 12 months.
5. Two nearly new, used 5 MW transportable GT units may be possible to acquire to a shorter time. Their availability and cost are functions of the market place. The units may also have to be adapted to suit Holyrood conditions (motor and start voltages, applicable codes, design fuel combustors, NOx levels).
6. Emissions, particularly NOx emissions, will have to be addressed:
    i) NOx emissions are dependent on the nitrogen content of the diesel fuel oil used.
    ii) NOx emissions will be lower than those of the current GTG units, but being oil fuelled units will be challenged to meet Canadian Council of Ministers of the Environment (CCME gas turbine NOx emission guidelines
    iii) Newfoundland & Labrador environmental regulations require Best Available Control Technology (BACT), although the regulations have provisions relaxing BACT requirements for both economic impacts as well as flexibility of approval by the Minister considering roles.
        a. The current designs do not have special technology (i.e. Selective Catalytic Reduction (SCR)). Their costs, the impacts of the technology on black start readiness and reliability, and the costs and impacts of ammonia use and storage for SCR use, make their consideration unreasonable for the roles contemplated.

b. A project going forth will have to seek approval for an exemption from the BACT requirement, and will likely have restrictions placed on the unit such as a limit on the number of operating hours per year.

7. Five MW units are likely the upper limit of useful unit size for redeployment in support of transmission and distribution line maintenance support either post 2020 or periods up to 2020.
8. The earliest in-service date for procuring and installing 2 x 5 MW new gas turbine generators is May 2013. The earliest in-service date for procuring and installing 2 x 5 MW nearly new/used gas turbine generators is March 2013.
9. The capital cost for procuring and installing 2 x 5 MW new gas turbine generators is $13.3 million. The capital cost for procuring and installing 2 x 5 MW nearly new/used gas turbine generators is $11.5 million.

New and Nearly-New 5 x 2MW Portable/Transportable Diesel Engine Generator Units

1. The five 2 MW transportable diesel engine generator units option is potentially consistent with the requirements for black start power, but:
   i) The units may have significant difficulty responding to a block load start of 3 MW power block (one boiler feed pump motor), and
   ii) Islanded synchronous operation during start-up of five units may be difficult to maintain and affect overall system capacity available and overall system start-up reliability. It will also likely require a more complex control system.
2. The space requirements for the five 2 MW transportable diesel engine generator units (5 trailers plus two electrical trailers plus a common electrical building) cannot be accommodated in the existing GT area.
   i) Space and civil requirements suggested that use of the existing well graded area behind the old security building was the best location.
   ii) Spacing requirements are increased by separation requirements between units
3. Five new 2 MW transportable diesel engine generator units could be readily purchased, with a manufacturing time of about 12 months.
4. Five nearly new, used 2 MW transportable diesel engine generator units may be possible to acquire to a shorter time. Their availability and cost are functions of the marketplace and the units may have to be adapted to suit Holyrood conditions (motor and start voltages, applicable codes, design fuel combustors, NOx levels).
5. Emissions, particularly NOx emissions, will have to be addressed:
   i) NOx emissions are dependent on the nitrogen content of the diesel fuel oil used.
   ii) NOx emissions, particularly for some used engines, may not be lower than those of the existing GT unit. They will have higher emission levels than the GT options.
   iii) Applicable diesel engine generator emission regulations in the US and Canada are in flux, with significantly more stringent requirements likely for units coming into service in the 2012 through 2015 period. Emergency power non-mobile (i.e. not on road or off-road units) will face significant but less stringent levels, but will have their operation limited to emergency use only (in effect similar to the restriction imposed on the existing GT).
   iv) Newfoundland & Labrador environmental regulations require BACT, although the regulations have provisions relaxing BACT requirements for both economic impacts as well as flexibility of approval by the Minister considering roles.
      a. The current designs do not have special technology (i.e. Selective Catalytic Reduction (SCR)). Their costs, the impacts of the technology on black start

readiness and reliability, and the costs and impacts of ammonia use and storage for SCR use, make their consideration unreasonable for the roles contemplated.

b. A project going forth will have to seek approval for an exemption from the BACT requirement, and will likely have restrictions placed on its role and likely a limit on the number of operating hours per year.

6. Two MW units are good candidates for redeployment in support of transmission and distribution line maintenance support either post 2020 or in possible periods up to 2020. They are typical of larger unit sizes deployed for that purpose now.
7. The earliest in-service date for procuring and installing 5 x 2 MW new diesel gensets is May 2013. The earliest in-service date for procuring and installing 5 x 2 MW nearly new/used diesel gensets is March 2013.
8. The capital cost for procuring and installing 5 x 2 MW new diesel gensets is $10.8 million. The capital cost for procuring and installing 5 x 2 MW nearly new/used diesel gensets is $9.6 million.

Overall Economics

Using the Assessment Basis,

1. The base capital cost comparison of the options is as follows:

BASE CAPITAL COST COMPARISON OF OPTIONS

Capital Cost Comparison
Capital cost estimate $1,000 Can 2011

Option Number	**0**	**1**	**1A**	**2**	**2A**
Option	**Existing GT Refurb**	**New 2 x 5 MW GT**	**Used 2 x 5 MW GT**	**New 5 x 2 MW Diesel**	**Used 5 x 2 MW Diesel**
GT/Diesel Cost	$2,950	$10,865	$9,234	$8,553	$7,453
Civil Works	$224	$131	$131	$131	$131
Electrical Works	$541	$759	$759	$801	$801
BOP Systems	$330	$129	$129	$129	$129
Existing Unit Demolition & Removal	$0	$7	$7	$7	$7
Sub-Total - Directs and Indirects	$4,046	$11,891	$10,260	$9,620	$8,520
Project Engineering	$324	$625	$544	$513	$458
Project Management	$283	$832	$718	$673	$596
Total	$4,652	$13,348	$11,522	$10,807	$9,575

+ Standby = Total	$4,825
+ New Rental Stdby = Total	$9,421

- The life cycle cost comparison of the options in 1) un-escalated non-discounted (not present worthed), 2) un-escalated discounted (present worthed), 3) escalated non-discounted (not present worthed), and 4) escalated discounted (present worthed) costs is as follows.

The existing unit refurbishment option costs include the lower cost standby option assuming that a replacement gas generator and power turbine are leased and installed while the existing units are sent out for refurbishment. This adds only about $170,000 to the base cost. The existing unit refurbishment option costs assuming the standby option using a complete, installed 2 x 5 MW nearly new GT leased option would add an additional $4.7 M. The options include a cost for differences in the likelihood of a failure occurring once during the period – an additional $10 million (2011 Cdn $) in 2016 for the existing GT and $4 million in 2016 for the 5 x 2 MW diesel options.

		Refurbished Unit, Use of Spare Gas Generator & Power Turbine					
		Capital Cost	OMA	Fuel	Sub-Total	Elect Value	Total
1	UNESCALATED	$14,825	$1,885	$1,408	$18,118	($1,648)	$16,470
2	UNESCALATED, DISCOUTED CASHFLOW	$11,454	$1,291	$959	$13,704	($1,122)	$12,582
3	ESCALATED CASHFLOW	$16,260	$2,159	$1,660	$20,079	($1,943)	$18,136
4	ESCALATED, DISCOUTED CASHFLOW	$11,521	$1,302	$992	$13,815	($1,161)	$12,654

		Option 1 New 2x5 MW GT					
		Capital Cost	OMA	Fuel	Sub-Total	Elect Value	Total
1	UNESCALATED	$6,348	$1,714	$1,237	$9,300	($1,648)	$7,652
2	UNESCALATED, DISCOUTED CASHFLOW	$8,766	$1,175	$842	$10,783	($1,122)	$9,661
3	ESCALATED CASHFLOW	$4,940	$1,963	$1,459	$8,362	($1,943)	$6,419
4	ESCALATED, DISCOUTED CASHFLOW	$8,731	$1,185	$871	$10,787	($1,161)	$9,626

	Option 1A Used 2x5 MW GT					
	Capital Cost	OMA	Fuel	Sub-Total	Elect Value	Total
1	$7,522	$1,714	$1,237	$10,473	($1,648)	$8,826
2	$8,632	$1,175	$842	$10,649	($1,122)	$9,527
3	$6,815	$1,963	$1,459	$10,236	($1,943)	$8,294
4	$8,618	$1,185	$871	$10,674	($1,161)	$9,513

		Option 2 New 5x2MW Diesel					
		Capital Cost	OMA	Fuel	Sub-Total	Elect Value	Total
1	UNESCALATED	$9,807	$323	$1,237	$11,366	($1,648)	$9,719
2	UNESCALATED, DISCOUTED CASHFLOW	$10,231	$220	$842	$11,293	($1,122)	$10,171
3	ESCALATED CASHFLOW	$9,358	$370	$1,459	$11,187	($1,943)	$9,244
4	ESCALATED, DISCOUTED CASHFLOW	$10,232	$222	$871	$11,325	($1,161)	$10,164

	Option 2A Used 5x2MW Diesel					
	Capital Cost	OMA	Fuel	Sub-Total	Elect Value	Total
1	$10,575	$323	$1,237	$12,134	($1,648)	$10,487
2	$10,128	$220	$842	$11,190	($1,122)	$10,068
3	$10,593	$370	$1,459	$12,422	($1,943)	$10,479
4	$10,143	$222	$871	$11,236	($1,161)	$10,075

RECOMMENDATIONS

1. The existing gas turbine generator should not be operated (started, operated, shut down), except in an emergency situation, and in such an emergency its operation should be observed remotely.
2. Using the Assessment Basis, the preferred option is Option 1, the 2 x 5 MW new GT installation.
3. Hydro should review the Assessment Basis and any impacts of changes in it as part of its internal decision-making process on the options.
4. Hydro should proceed with a preferred option as soon as practically possible, given that the likelihood of safely and successfully starting the existing GT unit in an emergency condition in its existing state is very poor and likely to decrease rapidly with time idle.
5. If Hydro internally chooses refurbishment of the existing GT generator as its preferred option, then the existing GT generator should undergo an extensive overhaul and repair program, including:

    i) Gas Turbine Unit

        a. Power turbine disk replacement (9 month manufacturing lead time);
        b. Power turbine damaged blades replacement (one or more) or significant repair;
        c. Gas generator blading cleaning and recoating;
        d. Inlet filter media replacement and inlet duct refurbishment (including cooling air duct to power turbine disk); and
        e. Exhaust stack replacement or extensive repairs

    ii) Gearbox lube oil system modification and refurbishment

        a. Seals replacement/modification;
        b. Venting system modifications to reduce lube oil pressure buildup;
        c. Lube oil pump system upgrade for start-ups; and

d. Lube oil cooling fan replacement

iii) Gearbox bearings refurbishment or replacement and/or unit re-alignment

iv) GT Generator testing and refurbishment

a. Unit generator electrical testing and possible rewind; and
b. Unit generator exciter testing, and refurbishment/replacement as necessary

v) GT electrical and controls system update to compliance with current standards and/or obsolescence replacement

a. Unit AVR
b. Unit MCC's

vi) The GT and generator enclosure rooms' fire detection and suppression systems modifications to provide better coverage (as evidenced by the failure of the system to initially detect or suppress the gearbox lube oil fire in 2010).

vii) GT fuel oil receiving, forwarding, and delivery system replacement in an enclosed shed.

viii) GT generator building repairs:

a. Major leaks in and around the gas turbine exhaust stack
b. Minor leaks at generator ventilation stack
c. Minor air leaks as a result of minor siding holes (corrosion)

ix) Expansion of the electrical services room to allow for new electrical systems and current systems to be in compliance with current standards (i.e. space, separation distance for arc flash)

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GLOSSARY

°F or oF	Degree Fahrenheit
°C or oC	Degree Celsius
ATS	Automatic Transfer Switch
BTU	British Thermal Unit
CO2	Carbon dioxide
CW	Circulating or cooling water
DCS	Distributed Control System
DG	Diesel Generator
Gen	Generator (Only)
GTG	Gas Turbine Generator
HP	High Pressure
JB	Junction Box
kV	Kilovolt
kVAR	Kilovolt ampere reactive
kW	Kilowatt
kWh	Kilowatthour
LP	Low pressure
Max	Maximum
MCC	Motor control centre
MCR	Maximum continuous rating
mm	Millimetres
Mg	Megagrams
mg	Milligrams
MOT	Main output transformer
MTS	Manual Transfer Switch
MVA	Megavoltampere
MVAR	Megavolt ampere reactive
MW/MWg/MWn	Megawatt /megawatt gross/megawatt net
MWh/MWhg/MWhn	Megawatt hour/ megawatthour gross megawatthour net
Min	Minute
O2 or O_2	Oxygen
psig or psi_g	Pound per hour pounds per square inch gauge
psia or psi_a	Pounds per square inch absolute
ppmvd or ppm_{vd}	Parts per million (dry volume basis)
%	Percentage
PT	Power Turbine
Rpm	Revolutions per minute
Scfh	Standard cubic feet per hour
T9	Transformer #9
TGS	Thermal generating station
VAR	Vars
V	Volts

HOLYROOD THERMAL GENERATING STATION GAS TURBINE CONDITION ASSESSMENT & OPTIONS STUDY

1 INTRODUCTION

1.1 Holyrood Thermal Generating Station and Black Start Gas Turbine Generator

1.1.1 Holyrood Thermal Generating Station (Holyrood)

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

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

1.1.2 Holyrood Black Start Gas Turbine Generator (GT)

The Holyrood gas turbine generator is a nominally 13.5 MW packaged generating unit system. It serves as a black start unit for the station and is occasionally used for system support. Due to the critical nature of the role that the Holyrood GT plays, it must operate with a high degree of operational reliability.

The gas turbine generator is comprised of a number of components: inlet plenum, AVON 1533-70L gas generator and power turbine, exhaust system, gearbox, generator, fuel oil system, governor/fuel control and lubricating oil system.

Ambient air enters the intake structure, passes through an intake air filter and enters the inlet air plenum. The air is compressed via a 17- stage axial flow compressor in the forward section of an AVON 1533-70L.gas generator. Fuel is supplied to an eight burner combustion section between the gas generator air compressor section and its turbine section. Combustion of the fuel results in a rapid increase in the temperature and velocity of the axial hot combustion gas flow. A three-stage turbine in the back end of the AVON 1533-70L uses a portion of the axial combustion gas flow to increase compressor rotational speed and to boost delivery. The high temperature, high velocity gas is then used to drive the power turbine and generator through a gearbox. The engine has its own on-board lubrication system complete with circulating pumps and a reservoir. The combustion gases then pass through an exhaust volute and to the atmosphere via an exhaust stack.

1.2 Project Description & Scope

The gas turbine went in service at Holyrood in 1986. As of December 2010, the unit had a total of approximately 4717 operating hours, +386,000 idle hours, and 2548 starts. Due to the age of the gas turbine and balance of plant, the large number of idle hours, and its exposure to a marine environment, it was necessary to perform a comprehensive condition assessment and life extension study. In general, the unit and balance of plant equipment requires refurbishment or replacement work to continue operating with a high degree of reliability to its required end of life of 2020. The study will identify the measures that need to be taken to ensure reliable operation of the gas turbine (GT) and balance of GT. AMEC Americas Limited (AMEC) was contracted by NL Hydro to conduct a Condition Assessment and Refurbishment/Replacement Study for the Holyrood BlackStart Gas Turbine Generator.

The scope of work consists of an engineering study that will assess the condition of the Holyrood Thermal Generating Station (HTGS) gas turbine and balance of plant and make recommendations for work including cost estimates that will be required to extend its useful life to 2020 with the same high degree of reliability as that experienced in the past. The engineering study will include a Level 2 study as per the guidelines of the Electrical Power Research Institute (EPRI). During the 1970's and 1980's, EPRI developed a three level methodology for performing condition assessment and life extension studies within the utilities industry in which the level of sophistication and detail increases progressively through Level I, Level II, and Level III studies. AMEC shall apply this process to the gas turbine generator and balance of plant equipment.

Part A of the study is primarily a detailed condition assessment and refurbishment study of the existing gas turbine plant located at HTGS with recommendations and cost estimates to extend the life of the gas turbine plant as a highly reliable operation to the year 2020.

Some GT equipment vendors had already issued their condition reports to Hydro. Hydro made these reports available to AMEC. Following an analysis of the reports and consultation with vendors, AMEC shall make recommendations for refurbishment work necessary to extend the life of the gas turbine plant as a highly reliable operation until the year 2020. Cost estimates shall be provided for the recommendations, in addition to giving consideration to the vendor reports.

Part B of the study examines the replacement of the existing gas turbine plant with a new or good used mobile generating plant considering either:

a) A gas turbine plant consisting of two 5 MW mobile/transportable units.

b) A diesel generating plant consisting of five 2 MW diesel units.

If used generating plants are considered, they are required to be relatively new and in good condition.

The new plants are to be able to support start-up block loads up to 3 MW in a smooth and stable manner. The scope would include the decommissioning of the existing plant and removing it from site. The new units would be installed such that uninterrupted black start power availability would be provided to HTGS until new mobile installations are commissioned.

AMEC shall determine the annual operating and maintenance (O&M) cost for each of the alternatives up to the year 2020.

1.3 Study Basis

The basis for the study is as follows:

In-Service: Summer 2013

End of Life (EOL):

- **Holyrood Black Start:** Dec 2020 in Holyrood black start service
- **System Support:** Post 2020 for replacement options - transportable for transmission/ distribution system maintenance to various locations for further 10 to 15 years

Operating Pattern:

- **To 2020:** 1 start every 2 weeks to 50%+ load for two hours in winter; 1 start per month in summer; System use – 20 to 40 hrs/year
- **Post 2020:** Maximum 1 month/year operation on transmission line outage support – Maximum 720 hours per year , 6 starts/year

Capacity Targets: 10 MW gross peak capacity; Continuous capacity – vendor capacity based on gross peak capacity

Energy Targets: No specific energy production targets – Capacity and Operating Pattern define role.

Reliability Targets:

Start Reliability:	80% (2nd start – 96%, 3rd start – 99 %)
Black Start Ops Reliability:	98%
Peaking Reliability:	95%
Availability:	93% (Summer maintenance)

Health & Safety Target; Maximum Practically Achievable Safety

- Minimum fire risk
- Minimum catastrophic equipment failure risk

Environmental & Regulatory Target: Meet Newfoundland & Labrador environmental and regulatory requirements for the technology and role of the facility

1.4 Methodology

1.4.1 Part A – Existing Unit Refurbishment

GT equipment vendors previously issued their condition assessment reports to Hydro. Hydro made these reports available to AMEC. An analysis of these reports, and consultation with vendors, forms the basis for AMEC's recommendations for refurbishment work necessary to extend the life of the gas turbine plant as a highly reliable operation until the year 2020. Cost estimates were not provided by the vendors for the recommendations in their assessments. In addition to giving consideration to the vendor reports AMEC shall perform the following tasks in completing the Project.

1. Conduct Equipment Inspections – Balance of Plant (BOP)

AMEC developed a plan, including a schedule, to perform detailed inspections of the remaining gas turbine balance of plant systems and sub systems and identify refurbishment needs. Following the completion of the inspection, AMEC formulated recommendations for refurbishment work complete with cost estimates, including a schedule, that are required to extend the life of the balance of plant systems until the year 2020. The OEM's and other specialists were consulted as required to assist in the study. AMEC contacted OEM's and other specialists to provide this information to AMEC. The remaining gas turbine BOP systems and sub systems addressed by this study included the following:

1. Fuel oil system
    - i. Fuel tanks
    - ii. Fuel oil piping
    - iii. Fuel offloading pumps
    - iv. Valves
    - v. Fuel supply pumps (to the gas turbine)
    - vi. Strainers and filters
    - vii. Fuel flow meter
    - viii. Fire system trip valve
2. Electrical and controls
    - i. Foxboro DCS system
    - ii. DCS logic
    - iii. MCC
    - iv. Switchgear
    - v. Governor system
    - vi. Battery room
3. Compressed air system
    - i. Compressor unit
    - ii. Instrument air dryer
    - iii. Control panel
    - iv. Nitrogen back-up bottle supply
4. Building
    - i. Structure
    - ii. Fire protection system
    - iii. Crane hoist and track system

2. Major Upgrades and Repairs

A number of major upgrades and repairs have been performed on the HTGS gas turbine and balance of plant since it went into service in 1986. AMEC reviewed available plant records pertaining to major equipment upgrades and repairs and evaluate their impact on achieving 2020 service life.

3. Determine Remaining Equipment Life

AMEC assessed the remaining lifetimes of the gas turbine plant major components and systems along with the balance of plant, consulting as required with OEM's and reviewing the historical life cycle information for similar type facilities to assess the requirements to reach an end of life of the gas turbine plant of 2020.

4. Determine Annual Operating and Maintenance Cost

AMEC determined the annual operating and maintenance (O&M) cost for the gas turbine plant up to the year 2020, both with the recommended refurbishments and without completing the recommended refurbishment work. AMEC contacted OEM's and other specialists as required to support development of this information.

1.4.2 Part B – Existing Unit Replacement

AMEC developed a scope of work and cost estimate to replace the existing gas turbine plant with a new or good used mobile generating plant considering alternative arrangements as noted below. If used generating plants are considered they are required to be relatively new and in good condition.

a) A gas turbine plant consisting of two 5 MW mobile units.

b) A diesel generating plant consisting of five 2 MW mobile diesel units.

The alternative arrangements were configured such that the new plants would be able to support start-up block loads up to 3 MW in a smooth and stable manner. In addition, cost estimates included decommissioning of the existing plant and removing it from site. The alternatives considered were such that uninterrupted black start power availability would be provided to HTGS until new mobile installations are commissioned.

AMEC determined the annual operating and maintenance (O&M) cost for each of the alternatives up to the year 2020.

The study methodology included the following steps:

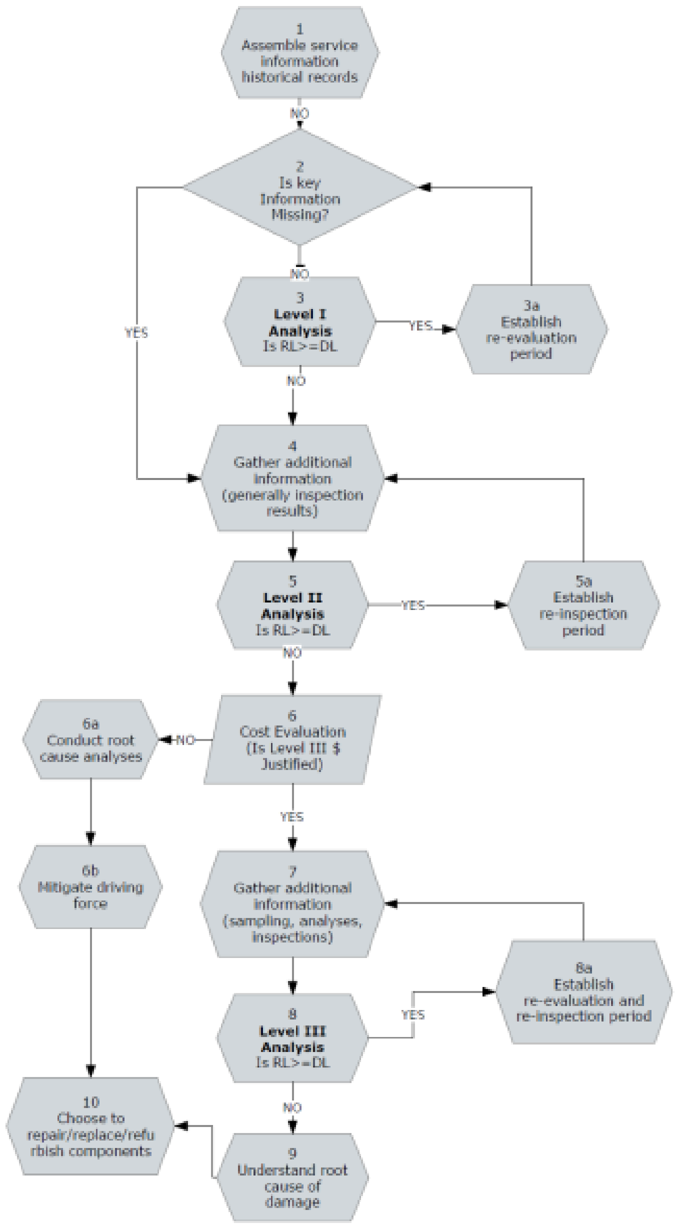
- Initial kick-off meeting and site visit
- Site review and equipment/facility inspections
- Review of the Holyrood Plant Maintenance Program – existing information/background data and staff interviews
- Review and analysis of information and data obtained through:
    2. Existing studies on condition assessment, life expectancy, previous studies of life extension, and the associated costs (capital and O & M) of such programs
    3. Previously noted physical inspection reports of equipment
    4. Equipment lost time analysis data
    5. Interviews and discussions with NL Hydro management
    6. Interviews and discussions with Holyrood Operations and Maintenance personnel
    7. Analysis of power demands vs. Holyrood generation capabilities
- Analysis of the impact and value of capital upgrades and operational and maintenance improvements
    1. Determination of remaining equipment and facility life – using existing information, experience, and OEM consultations as required to develop life cycle curves for major critical equipment and facilities not expected to exceed the 2020 end of life date; and
    2. Conduct equipment risk of failure analysis for major plant components, equipment, systems, and the entire facility which is not expected to exceed the 2020 end of life date.

3. Identify any components or systems that require further investigation; and make recommendations for work that will be required to extend the plant's useful life to 2020 with the same high degree of reliability as experienced in the past.

To the extent practical, the approach followed the intent of the EPRI Condition Assessment Level 2 process or a reasonable alternative approach as determined by individual technology experts. The basic approach consistent with the EPRI Level 2 approach is:

- Examine design or overall service parameters
- Perform Level 2 inspections (physical only, no testing)
- Compare, using conservative considerations, the expected residual life to the required 2020 service period (or the interval to the next inspection whichever is less)
- Incorporate service and measurement information where practical, available and useful including:
  1. Unit running hours
  2. Numbers of starts and stops – hot, warm, cold, trips, ramp rates
  3. Unit load records
  4. Failure history and analyses reports
  5. Maintenance activities
  6. Specifics of past component repairs and replacements
  7. Materials of construction composition checks
  8. Dimensional checks
  9. Design parameters

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



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

FIGURE 1-1 GENERIC EPRI CONDITION ASSESSMENT METHODOLOGY

For mechanical systems, it considers aspects such as:

Feature	Level I	Level II	Level III
Failure History	Plant records	Plant records	Plant records
Dimensions	Design or nominal	Measured or nominal	Measured
Condition	Records or nominal	Inspection	Detailed inspection
Temperature and pressure	Design or operational	Operational or measured	Measured
Stresses	Design or operational	Simple calculation	Refined analysis
Material properties	Minimum	Minimum	Actual material
Material samples required?	No	No	Yes

More rigorous assessment →

More accurate operation data required →

More accurate estimate of equipment RL →

FIGURE 1-2 EPRI METHODOLOGY – INFORMATION REQUIREMENTS

The Level 2 analysis considers several issues, such as:

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

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

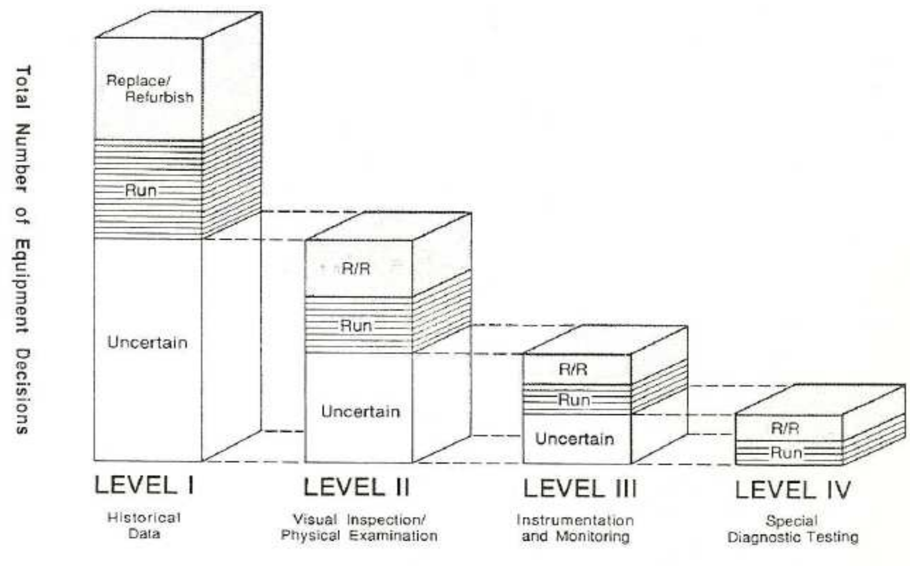


FIGURE 1-3 FOUR-LEVEL ELECTRICAL COMPONENT LIFE ASSESSMENT

1.5 Background Information and Studies

The key background information and studies included the following:

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

1.6 Field Investigation

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

- Operating hrs and cold/warm/hot starts;
- Major outages and associated reports (planned, major maintenance);

- Major plant equipment and system changes (i.e. equipment change-out, major gas turbine modifications and generator modifications) since in-service (particularly in last 10 years) including the scope and timing of the changes;
- Major inspections (and associated reports) on key equipment and systems;
- Unit performance – capacity, heat rate, availability;
- Current budget and business plan information details; and
- Occurrences where the actual operating conditions exceeded the equipment design conditions.

1.7 Scope, Key Features and Parameters of Study

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

- AMEC would adapt the Holyrood asset register as the primary index.
- The generic EPRI Condition Assessment approach illustrated in Figure 1-1 is the methodology employed. A more generic approach, using industry and individual expert experience, taking into account Holyrood specific information, was applied in many cases.
- The intent is to provide an assessment of requirements including schedule and cost. Given the stage of and eventual scope of the work, as well as the economic environment, an accuracy of +/- 10-15% is a target typically achieved during detailed quotes on actual work, and the overall costs are practically speaking more of a +10/-25% quality, typical of this stage of the work.

The following key features of the study were identified:

- No new detailed information was developed. The assessment was based on existing information obtained through existing documents and studies, plant interviews, and readily undertaken visual inspections
- The findings of existing studies are taken into account.
- The intent of the EPRI Level 2 methodology is to determine whether a piece of equipment or system can either reach it's intended planned life or reach its next major inspection and overhaul. If it is indeterminable as to whether the equipment can or cannot reach its planned life or next major inspection/overall, then a Level 3 condition assessment is necessary.
- The study focuses primarily on key equipment systems required for black start operation up to 2020
- Inspection and analysis has been done by others on the major gas turbine OEM equipment as per the RFP document. AMEC will use this condition and cost information as the basis for its gas turbine assessment.
- No inspections were required for equipment identified in the Level 1 study as satisfactory – for example: fuel tanks, building siding, recent electronics equipment additions.
- EPRI Level 2 inspections were limited to equipment identified as BOP and for which visible and practical inspections are possible in AMEC's judgment.
- Inspections were only undertaken per above and only on key equipment that is not considered covered under regular OMA, but represented a life limiting issue having a probable and significant impact on the reliable operation of the unit in AMEC's judgment.
- No specific equipment testing was undertaken as a Level 2 exercise.
- Remaining life was determined and reported on for those major systems and pieces of equipment which are expected to fail before 2020 and have a significant reliability impact on the gas turbine unit in AMEC's judgment.

1.8 Cost Estimating and Schedule

AMEC developed cost estimates and schedule for both Part A and Part B options - to complete a GT refurbishment as well as to replace the existing gas turbine unit with either 2 x 5 MW gas turbine generators or 5 x 2 MW diesel engine generators. Where practical, the cost estimate targeted an accuracy range of +/- 10-15%. It was identified and agreed that this would not be practical in many cases given the stage of work and the labour and materials marketplace and any key considerations pertinent to completing the cost estimate and schedule provided.

1.9 Site Visits

AMEC staff visited Holyrood in May-June 2011:

- A one-week visit by Rupert Merer (GT expert) and Blair Seckington; and
- Various short term visits by several of AMEC St John's office staff with Civil, Structural, Electrical & Controls, and Mechanical expertise.

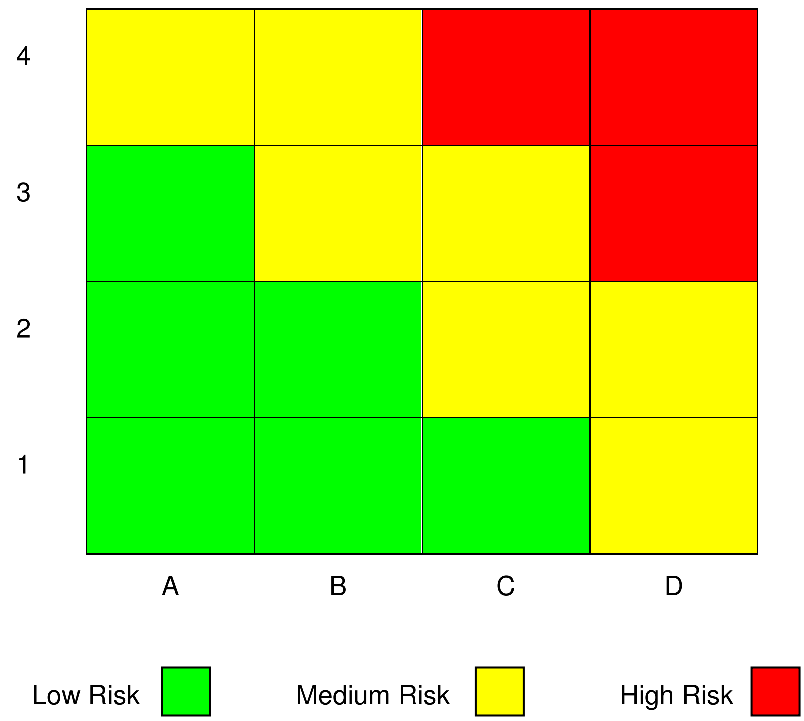
In the course of these visits, meetings and interviews included the following staff:

- Plant management team as a whole – kick-off, scope, areas of responsibility, and general information sharing;
- Terry LeDrew (Plant Manager) – key plant issues and asset history;
- Jeff Vincent (Manager-Long Term Asset Planning) – various plant asset conditions, capital plans, Instrumentation and Controls (I&C), Electrical, and organization;
- Wayne Rice (Manager-Work Execution) – various equipment and system conditions and plant staffing;
- Sean Mullowney (Plant Electrical Engineer) – various technical issues and programs regarding electrical systems, instrumentation, and controls;
- Jamie Curtis (Quality Assurance Engineer) – NDE and test program results;
- Christian Thangasamy (Plant Mechanical Engineer) – various technical issues and programs related to condensers, boilers, synchronous condenser, steam turbine generator, motors, and pumps;
- Mike Manuel (Manager-Environment, Health and Safety) – reliability;
- Alonso Pollard (Performance Specialist) – performance data (reliability and availability);
- Gerard Cochrane (Manager - Operations) – plant and equipment performance issues, plant operations issues;
- Plant Shift Supervisors and Operators (various) – plant operations issues and performance;
    - Ron MacDoanald, Willis Young
- Ron LeDrew (Emergency Response Coordinator) – Emergency Response Team (ERT) activities;

1.10 Technological Risk of Failure Analysis

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

TABLE 1-1 TECHNOLOGICAL RISK OF FAILURE ANALYSIS MODEL



<u>Likelihood of Failure Event:</u>

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

<u>Consequence of Failure Event:</u>

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

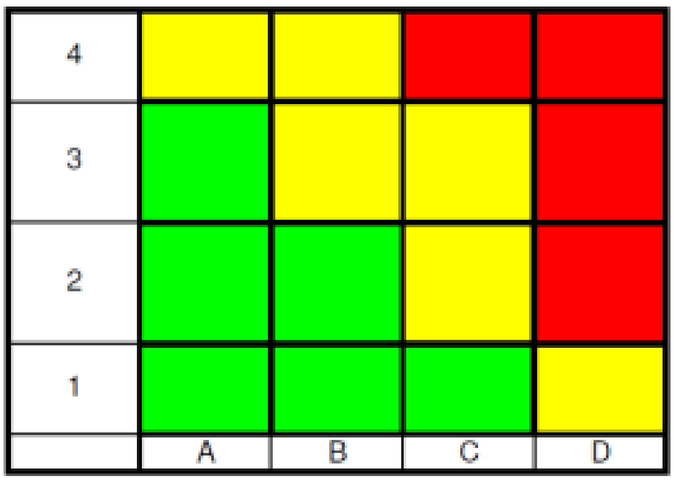
<u>Actions:</u>

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

1.10.1 Safety Risk Failure Analysis

In addition to the technological risk of failure analysis, a preliminary safety risk of failure analysis was undertaken at NL Hydro's request. Its basic format is based on that of the technological risk assessment model above and is somewhat of a hybrid of the more complex "Real Hazard Index" model used by the US Department of Defence. The modified model is presented below in Table 1-2.

TABLE 1-2 SAFETY RISK FAILURE ANALYSIS MODEL



Low Risk Medium Risk High Risk

<u>Likelihood of Safety Incident Event:</u>

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

<u>Consequence of Safety Incident Event:</u>

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

<u>Actions</u>:

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

1.11 Priority Rating

A numbered priority was assigned to the various “Recommended Actions”, “Level 3 Inspections”, and “Capital Enhancements” of this report. The scale used was from “1” to “4”. A “1” is the highest priority and essentially means that this activity should definitely be undertaken and where practical in or about the timing identified. A “4” is the lowest priority and essentially means that the item is essentially low risk and low impact and may be much more readily delayed or undertaken in some other fashion. The priority ranking is a subjective relative ranking by AMEC, meant to be an aid to Hydro in allocating resources and assessing trade-offs and program delays.

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

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

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

2 EXISTING GAS TURBINE CONDITION ASSESSMENT

2.1 Gas Turbine Unit and Equipment/Processes

Unit #:	GAS TURBINE
Asset Class #	BU 1273 Gas Turbine
SCI & System:	7202 Gas Turbine System
Sub-Systems:	7058 GT Power Turbine & G/B 7308 GT Avon Jet Engine 7309 GT Generator

2.1.1 Description of Holyrood API Gas Turbine

The Holyrood API gas turbine is a 10/12 MW aeroderivative packaged power plant using a Rolls Royce Avon gas generator. It was designed for peaking duty to provide black start capability to the Holyrood Generating Station. The Holyrood unit is the first API produced, and had guaranteed ratings, at ISO conditions, of 12 MW peak and 8.4 MW base load. It was originally installed at Hardwoods, but moved to Holyrood in 1970. In 1986 the plant was removed from its enclosure and re-installed in a custom building with a new exhaust stack with exhaust silencer and inlet filter house.

The gas turbine generator is comprised of a number of components: inlet plenum, AVON 1533-70L power turbine, exhaust system, gearbox, generator, fuel oil system, governor/fuel control and lubricating oil system.

Ambient air enters the intake structure, passes through an intake air filter and enters the inlet air plenum. The air is compressed via a 17- stage axial flow compressor in the forward section of an AVON 1533-70L.gas generator. Fuel is supplied to an eight burner combustion section between the gas generator air compressor section and its turbine section. Combustion of the fuel results in a rapid increase in the temperature and velocity of the axial hot combustion gas flow. A three-stage turbine in the back end of the AVON 1533-70L uses a portion of the axial combustion gas flow to increase compressor rotational speed and to boost delivery. The high temperature, high velocity gas is then used to drive the power turbine and generator through a gearbox. The engine has its own on-board lubrication system complete with circulating pumps and a reservoir. The combustion gases then pass through an exhaust volute and to the atmosphere via an exhaust stack.

The whole unit was re-housed in a custom building in 1986 with new filter house, generator filters, control room and exhaust stack. New stainless steel inlet splitters were installed. A new exhaust silencer and stack were installed with exhaust hoods, a number of control upgrades have been made, and the generator compartment was provided with new filter elements.

GTG Inlet Plenum

The inlet plenum is designed to provide approximately 140,000 cubic feet per minute of combustion air to the jet intake. This plenum is constructed of structural steel plate and framing supported by a concrete foundation. To reduce compressor damage and blade fouling, the inlet air must be free of dust and dirt.

Filtration is currently accomplished using a two stage filter. The first stage is designed for water removal, while the second was a high efficiency media type filter. It has 72 high efficiency "Farr" filter assemblies supported on tubular columns above the intake. The inlet silencer consists of acoustical splitters in a steel shell that is designed with round leading edges to create a bell-mouth entry. The trailing edges are tapered to ensure a low pressure drop and uniform flow characteristics. The plenum chamber is built from 10 cm (4 inch) thick noise-shield panels, packed with acoustic fill and secured to a rigid steel frame.

GTG Gas Generator

The gas generator employs a Rolls-Royce AVON 1533-70L (#37029) aeroderivative gas turbine manufactured by Associated Electrical Industries (AEI) of Manchester, England. Manufacture of this type generating unit began in the mid 1960's. The unit supplied to the Newfoundland and Labrador Power Commission in 1966 was the first one off the drawing board and was considered to be a development model. The three stage turbine in the aft end of the AVON 1533-70L uses a portion of the axial air flow to increase compressor rpm and boost delivery. The high temperature, high velocity gas exits the jet through an exhaust transition duct which is used to drive the Power Turbine and thus the generator through a gearbox.

The compressor of the Rolls Royce Avon is a single shaft axial compressor unit, with a 17 stage compressor giving a pressure ratio of approximately 10 in industrial service, 8 combustors in an annular arrangement and a 3 stage turbine.

The Rolls Royce Avon gas generator is a single shaft axial unit which was developed in the late 1940s and early 1950s as a prototype axial compressor unit. It is a first generation aero engine, with no bypass. It powered a number of aircraft in the 1950s and early 1960s and very successful adapted as a gas generator, especially in gas compressor drive applications where it established new standards in the late 1960s and 1970s for overhaul life or time between overhauls. TransCanada pipelines, and other North American pipelines, standardized on the Avon until more efficient second generation units became available.

GTG Power Turbine

The power turbine is an Associated Electric Industries Ltd. (AEI) design, manufactured in Manchester, England in early 1966. The power turbine is a single stage overhung machine designed for a normal operational speed of approximately 4900 rpm. The power turbine is connected to its generator via a gearbox and its output is converted to 1200 RPM in a vertical pinion and wheel gearbox (ratio of 4:1). The power turbine and gearbox are mounted on the centre section of the unit bedplate with this section also forming the main lubricating oil tank. Auxiliary and emergency oil pumps are mounted on this same base plate. The power turbine casings (volute) were replaced in 1986.

The power turbine uses heavy duty steam turbine construction techniques in contrast to the Avon. The power turbine shaft and disk are solid, although the inner cylinder which constrains the gas flow is fabricated from nimonic materials (nickel based alloys with high temperature tolerance). The power turbine disk is a low alloy ferritic material and it is probable that it has an operating limit of about 535 Deg C. It is cooled by a mixture of bleed air from the Avon and outside air. The power turbine diaphragm and moving blades are nimonic. The power turbine blading is nimonic and uses axially serrated roots, which are now common on modern gas turbines but were only used by AEI in the 1960s for highly stressed locations.

GTG Gearbox

The main gearbox was manufactured by AEI in Manchester, England. It is designed to provide an approximate 4:1 speed ratio from the power turbine shaft to the main generator shaft. The power turbine operates at about 4800 RPM and its output is converted to 1200 RPM in a vertical pinion and wheel gearbox. AEI had built quite complex marine and other gearboxes and the API unit was well within their experience. The gear train is fitted to the power turbine rotor by semi-flexible coupling housed within the gearbox. The gears are of the single helical, single reduction type with the pinion mounted directly above the wheel. A removable top cover allows for inspection without disturbing the alignments.

GTG Exhaust System

The exhaust casing (volute) is a welded fabrication divided along the horizontal centreline. It turns the combustion gasses transversely to the machine and vertically upwards to the exhaust silencer.

The exhaust stack is constructed of heavy gauge steel plate with light gauge steel cladding on the exterior. The exterior cladding of the lower half of the exhaust stack is constructed of heavy gauge steel plate. This stack was replaced during the 1986 major upgrade. The snow doors on the exhaust stacks are pneumatically actuated and were a new addition in 1986 to reduce corrosion of the volute and power turbine from infiltration of snow and rain water which promoted corrosion within the unit. New limit switches installed on the doors in 2009 indicate the position (opened or closed) of each door at the control station.

FIGURE 2-1 GTG GAS ENGINE & GENERATOR

Generator

The generator is an air-cooled, 14 MW, 13.8 kV, 3 phase, Type AG 80/100, built by Associated Electric Industries (AEI) of Rugby, England in 1966. It has a rotating-field, salient-pole tube with 6 poles and rotates at 1200 rpm. The brushless exciter eliminates the danger of contamination by carbon dust and minimizes maintenance. Semi-conductor rectifiers rotating within the generator/exciter shaft provide excitation for the main generator field.

Governor and Fuel Control

The standard Avon fuel control system is used without alteration as a basis for the API governing and fuel control system. The throttle valve is used as a generator valve and the H.P. cock as a fuel shut-off valve for normal and emergency shut-downs. The governing system is of the sensitive oil type in which fluid pressure is used to transmit the movement of the governor pilot valve to the operating mechanism of the governor valve, in this case the Avon throttle.

The governor is manufactured by Woodward and is driven via gearing from the end of the high speed pinion shaft. The governor is a fly-weight type and carries its own oil supply. Woodward Governor suggests that the present system has a reliability of about 50%. In addition, spare parts for this system are not carried and would have to be fabricated requiring long delivery times.

Excitation System

The exciter is a rotating brushless type mounted on a stub to the main rotating shaft. It was designed to ANSI Specification C50-1 3. The AC output from the exciter armature is fed through a set of diodes that are mounted on the rotor and are used to produce a DC voltage. The voltage is fed directly to the field winding of the main generator which is also mounted on the same rotating shaft.

The excitation control system consists of a "Normal" and "Standby" automatic voltage regulator (AVR) backed up by a "Manual" control mode. The AVR controls the strength of the magnetic field in the exciter by varying the amount of current through the stationary exciter field windings.

2.1.2 Operating History

Original Manufactured/Delivered	1966
In-Service Date at Hydro	1970
Rehoused at Holyrood	1986
End of Planned Life Date	2020
Last Combustion System Inspection/Overhaul	2009
Next Major Overhaul/Inspection/Refurbish/Replace	2012/13 (Recommended)

The gas turbine generator system at the plant serves as a black start unit for the station. It is occasionally used for system support as well. The hours associated with the unit are provided in Table 2-1 below.

To date, the gas turbine has operated for 4770 hours and 2548 starts. The numbers of hours operated during different phases are shown in the table, below.

TABLE 2-1 HOLYROOD API OPERATING HISTORY

	Hours	Starts	Hours/yr	Starts/yr	Starts/hr	Idle/hr
1966-1978	1749	611	140	47	3.0	85,000
1979-1985	390	185	65	32	2.0	85,000
1986-1995	1336	644	134	64	2.0	85,000
1996-2005	332	585	33	59	0.5	85,000
2006-2011	961	523	174	87	0.5	51,600
TOTALS	4770	2548				391,600

Peaking units traditionally operate for between 500-1000 hours per year, but the Holyrood API has averaged closer to 100 hours per year, and many of these hours, at least in recent years, have come from monthly test runs.

Some parts have been refurbished or replaced. The pattern used for the hours of operation and starts to the end of life date of 2020 is:

TABLE 2-2 HISTORICAL AND FORECAST OPERATING PATTERN

	Year To Dec 31	GT Ops Hrs		GT Idle Hrs		GT Starts		GT Ops Hrs/Yr		GT Starts/Yr	
		Low	High	Low	High	Low	High	Low	High	Low	High
Balance of Plant	1966	0		0		0					
	1978	1749		85000		611		139.9		48.9	
	1985	2139		170000		796		55.7		26.4	
	1995	3475		256000		1440		133.6		64.4	
	2005	3807		343000		2025		33.2		58.5	
	2010	4717		386000		2548		182.0		104.6	
	2011	4737	4737	394740	394740	2558	2563	20	20	10	15
	2012	4737	4737	403500	403500	2558	2563	0	0	0	0
	2013	4809	4887	412188	412110	2585	2635	72	150	27	72
	2014	4881	5037	420876	420720	2612	2707	72	150	27	72
	2015	4953	5187	429564	429330	2639	2779	72	150	27	72
	2016	5025	5337	438252	437940	2666	2851	72	150	27	72
	2017	5097	5487	446940	446550	2693	2923	72	150	27	72
	2018	5169	5637	455628	455160	2720	2995	72	150	27	72
	2019	5241	5787	464316	463770	2747	3067	72	150	27	72
	2020	5313	5937	473004	472380	2774	3139	72	150	27	72
Combustor:	2020	713	1337			1174	1539	72	150	27	72
PT Volute:	2020	2213	3837			1974	2339	72	150	27	72

The unit has operated for an average of about 100 hours per year and about 50 starts per year, consistent with use for emergency peaking. Although distillate fuel is used resulting in high unit energy costs, little attention has been given to efficiency due to the peaking/emergency roles of the unit. The station operators have demonstrated that they can usually start the unit fairly quickly, although it often takes several attempts. The station does not record starting reliability, which is one of the most important criteria for a normal peaking emergency unit.

One interesting aspect for early Avon units without corrosion protection was that each standby hour may have consumed the equivalent of 0.3 hours of running life. (Maintenance and Support of Mature Gas Turbines – M. Hudson, Siemens 2005)

2.1.3 Major Maintenance History

The API unit was originally supplied in its own packaging, but in 1986 the unit was relocated into a custom building with a new inlet filter house and exhaust stack. At that time a GEM80 PLC was installed.

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

The following is a summary of significant work completed since 2003. No major overhauls have been completed on the entire machine since 1991. No details of the overhaul work in 1991 (or prior) were available for this study. Limited data on the maintenance of the unit before 1986 was available, with the exception of the Avon.

16 October 2003

- Annual boroscope inspection;
- Slight erosion on casing. Re-protect next shop visit;
- Normal amount of carbon build up on nozzle heads;
- Boroscope inspection satisfactory; and
- Intake plenum contained debris, chipped floor and flaking paint. Recommended clean up.

10 August 2004

- Annual hot section inspection & failure to start;
- Housing found to have corrosion on struts, will require protective coating next shop visit;
- Air plenum cleaner than last visit, holes still visible in walls;
- Compressor rotor and stator vane blades in dirty condition;
- Normal amount of carbon build up on nozzle heads;
- Slight damage to #7 Combustion Can; and
- Starting motor replaced, due to seizure. (Solved starting issue).

27 September 2005

- Annual inspection and boroscope inspection;
- Front Bearing Housing, outer bushes loose;
- Front Bearing Housing, Corrosion/ pitting;
- Corrosion/ Rust found in Plenum;
- HP NGV's have slight erosion of the leading edges and minor cracks in the trailing edges;
- Flame tubes have minor erosion on some of the wiggle strips and some carbon build up within the flame tube, especially around the dish where liquid fuel has collected;
- Normal amount of carbon build up on nozzle heads; and
- Hot gas leakage at Exhaust Transition duct to power turbine.

13 March 2006

- Leak in each end of the gearbox at the bearing seals. (Caused fire when oil leaked into insulation around PT and dripped onto top of tank). Greenray discovered turbine shaft/seal modifications, recommended machining and reconditioning.

13 April 2006

- Fuel oil leak on underside of gas turbine at IGV Ram, seal deterioration.

25 May 2007

- AVON repair and boroscope inspection: IGV ram leak, ignitor failure, hot air leak from #6 burner, bellmouth nuts loose, combustion casing boroscope port bolts loose, bleed valve ducting broken and separated, fuel lag at idle and struggling at speed;
- Significant sparking coming from PT splash plate (rubbing shaft). Suggests bearings are worn and thus damaged seal;
- 2 IGV bushes replaced due to wear in the bush. (Majority of bushes and retaining nuts were replaced as well as the locking bush);
- Rebuild of the intake with securing bolts torque and locked;
- IGV ram replaced due to leak;
- Fuel filter replaced due to feed issues;
- Bolts holding PT seal were not tight, seal incorrectly installed;
- Ignitor, lead and box were replaced;
- High fuel consumption noticed at fuel drain valve, suspect worn seals on FCU and fuel pumps;
- Additional breather recommended for rear of gearbox unit, to reduce leaks;
- Compressor section; front bearing housing, inlet guide vanes have significant corrosion and coating loss;
- Combustion cans show signs of cracking, material loss (could lead to further turbine damage);
- IP nozzle guide vanes and HP nozzle guide vanes show signs of cracking on trailing edges;
- Change PT lube oil filters; and
- Replace/ Repair exhaust snow doors.

21 May 2008

- Package filtration inspection;
- Plenum survey;
- Windmill inspection of compressor;
- Boroscope of compressor and VIGV;
- Fuel/oil system: connection, fuel pump/ oil pump, pipelines, oil level & quality, filter and basket removal (replacement consumables);
- On engine review: bleed valves, IGV ram (filter review), gearbox inspection (filters, speed pick up, consumable change), fuel control unit review, oil cooler, fuel filter change, burner removal (ultrasonic cleaning), fuel rail inspection, drain valve operation, thermocouple inspection (terminal cleaning), transition inspection, removal of insulation, rectify leaks, inspect LP blades;
- Boroscope inspection: rear of compressor, snout area, combustion can, HP nozzle guide vanes, cooper beams (crooks washers), turbine section;
- PT and gearbox review; and
- Controls review.

10 June 2008

- Water pooling noted in intake plenum along with holes in structure and loose debris;
- Compressor showing significant corrosion and pitting on front bearing housing, inlet guide vanes and compressor stages, physical signs of salt evident;
- Combustion cans need to be replaced due to extensive corrosion, #1 and #2 burners removed for inspection. Seized bolts prevented removal of others;

- Hard impact damage evident in turbine stages, suspect debris from combustion cans and/or intake plenum;
- Suggested unit overhaul for blade recoating etc.; and
- Fuel pump and FCU to be repaired.

15 October 2009

- Engine removed and placed on site, in vertical stand for repairs (combustion cans);
- Combustion cans were replaced and FCU and fuel pump repaired;
- Loose discharge nozzles, due to broken brackets (2 off) to be replaced in future;
- PT inspection showed signs of light blade rub, none on stators. Diaphragm free of damage;
- PT inlet cone cranks, to be repaired;
- Thermocouple damage, quick fixed. To be upgraded;
- Exhaust stack needs replacement, lower components noted in good condition. Door opening components to be serviced; and
- Transition duct piston rings seals to be replaced.

20 November 2009

- Commissioning;
- Fuel control solenoid valve burnt out and replaced;
- Multiple start trips due to; low fuel pressure, low oil pressure, incomplete start sequence; determined igniter box malfunction, N2 probe incorrectly connected & FCU actuator tuning;
- Exhaust transition lagging replaced due to fuel saturation;
- Split air manifold cracks, to be repaired; and
- Suggest monitoring setup for the 8 EGT thermocouples.

2011

In the years 2010 and 2011, NL Hydro undertook a number of activities with vendors that have the Original Equipment Manufacturer (OEM) rights to the gas turbine sections in order to conduct internal inspections of the individual sections and prepare field inspection reports complete with refurbishment estimates.

1. Rolls Wood Group (OEM rights to the Avon gas generator) in 2011 conducted detailed internal inspections of the front end bearing assembly, compressor rotor, compressor casings, combustion assembly, nozzle casing, rear bearing housing, turbine assembly, exhaust unit, and accessory equipment and have prepared a field inspection report. Some refurbishment estimates were provided separately.
2. Greenray Turbines (Lincoln) Limited (OEM rights to the power turbine and gearbox) in 2011 performed detailed internal inspections of the power turbine and the gearbox gears, bearings, and seals.
3. Siemens (OEM rights to 14.150 MW generator including the direct couple cooling fan, the 73.5 KW brushless AC exciter, the AC lube oil pump motor, the DC back-up lube pump motor, and the 25 HP outside fuel off loading pump motor) performed detailed internal inspections and testing of the above noted equipment.

4. Braden Manufacturing is a company that specializes in the design and manufacturing of combustion turbine air filtration systems, air inlet systems, and exhaust systems. They were recently contracted by NL Hydro to perform detailed inspections of the gas turbine air inlet plenum, air filtration system, air inlet plenum support structure, exhaust stack and exhaust stack support structure.

GTG Inlet Plenum

When the API gas turbine was constructed, there was little experience of packaging units of this size and the API package was not adequate for the tough marine duty that the unit experienced. The inlet filters, exhaust silencer, exhaust stack and other components corroded quite rapidly and were all replaced in 20 years or less. The original inlet filters were the inertial type which was fairly standard at the time and were still the standard type of filter on TransCanada Pipeline (TCPL) units until the early 1970s. Inertial filters gave good performance in inland locations and places where the dust loading was not excessive. They were not completely satisfactory in icing conditions as the by-pass doors sometimes opened on overpressure, and TCPL suffered a number of cases of ice damage to Avon units. Inertial filters are not capable of handling a high salt content in the inlet air. The original stack had an internal liner which corroded rapidly and did not protect the outer layer against high temperatures. We have limited information on the original silencer splitters but the exhaust unit appears to have corroded very rapidly. We assume that it was not constructed from stainless steel.

The whole unit was re-housed in a custom building in 1986 with new filter house, generator filters, control room and exhaust stack. A new Farr filter building was purchased using a two stage filter- the first stage being designed for water removal while the second was a high efficiency media type filter. This filter was probably quite efficient when new, but with modern experience of high salt environments, largely gained from marine gas turbines, it is clear that its design was not adequate for a location within 200 ft of the ocean, where strong winds are common. Such a location would now require a 3 stage filter with one stage specifically designed for the removal of saline droplets. It is clear that the performance of the filter has deteriorated through time, and in recent years there has been increased evidence of salt ingestion in the Avon. The filter now has air gaps between the filter elements, due to rusting.

New stainless steel inlet splitters were installed and appear to have suffered little deterioration in the subsequent 25 years. A new exhaust silencer and stack were installed with exhaust hoods, and the stack has been severely corroded for a number of years. At the time a number of control upgrades were made, and the generator compartment was provided with new filter elements.

GTG Gas Generator - Avon

The early Avons were designed to have a Time Between Overhaul (TBO) of 1500 hours in peaking mode, and 8000 hours or more at base load. Later units achieved much higher base load overhaul intervals, but with some component upgrades. These overhaul intervals probably don't apply for a unit operating for fewer than 200 hours per year, but there is no established criteria for adjusting TBO for long periods of inactivity.

In any case the overhaul life of the Holyrood unit is much more influenced by the high salt atmosphere in which it operates, and the quality of inlet filtration. If the unit had operated entirely at base load in a clean environment, it would probably not require a hot end overhaul or the replacement of any hot end parts in less than 8000 hours.

Between 1966 and 1991, NL Hydro regularly sent the Avon unit to Rolls Royce Canada or other overhaul facilities, at significant expense.

The Avon was overhauled on the dates shown in Table 2-3 below.

TABLE 2-3 HISTORY OF AVON OVERHAULS

Year	Overhaul By	Overhaul Scope
1978	Not Available	Comp #7,8 replaced Titanium. Compressor recoated.
1986	Not Available	Overhaul
1991	GTC Scotland	Overhaul
1993	RR Canada	Hot End inspection
1997	RR Canada	Hot End inspection
1998	RR Canada	Inspection; replace IGV rams
1999	Onsite TCT	Boroscope and report. Minor work
2001	Onsite TCT	Boroscope and report. Minor work
2002	Onsite TCT	Boroscope and report. Minor work
2003	Onsite TCT	Boroscope and report. Minor work
2004	Onsite TCT	Boroscope and report. Minor work
2005	Onsite TCT	Boroscope and report. Minor work
2007	Onsite Alba	Boroscope and report. Minor work
2008	Onsite Alba	Boroscope and report. Minor work
2009	Onsite Alba	Replaced combustor cans.

The Avon has been inspected at regular intervals, as shown in Table 2-3. It has not been shipped to Rolls Royce or an OEM since 1991.

Since 1991, Hydro has arranged for a boroscope inspection at regular intervals, but the unit has not left the site. On each of the six inspections between 1999 and 2006, the inspection report stated that the unit appeared to be in satisfactory condition. A number of minor repairs have been made since 1991. They included replacement of inlet guide vanes (IGV) bushings and IGV rams, tightening of nuts and replacement of minor components but no major gas path component was replaced until 2009, when the combustor cans were replaced.

In recent years, the Avon has generally operated reliably. However, there is evidence of accelerated corrosion and pitting resulting from deterioration of the inlet filter. The filter is badly corroded and is now allowing unfiltered air to enter the plenum and the engine.

GTG Power Turbine

No major maintenance has been done on the power turbine since 1986. Access to the rotor and disk is difficult and until 2010, the only boroscope inspections which were done were performed from the front.

This allowed reasonable inspections of the inlet cones and the diaphragm ring, but not the rear of the turbine disk or the blade roots. In 2010, Greenway obtained a very limited boroscope picture of the power turbine blade roots. We have seen no record of any earlier inspection of the rotor, disk, blade roots or the whole of the moving blades.

GTG Gear Box

As early as 1970, the AEI engineers supervising the move of the unit to Holyrood noted several problems with the gearbox. These problems included leakage from the drive end bearing cover on the high speed pinion,) leakage from the generator end low speed shaft, and inadequate gearbox venting. The first of these problems was resolved by machining a groove in the cover plate and inserting an 'O' ring. The second issue was subjected to various adjustments and minor modifications so that the leakage was reduced to an acceptable level. The AEI Engineer's notes refer to components ordered from the factory to further reduce leakage, but the correspondence doesn't indicate what changes were made, and whether the new materials were ever fitted.

We do not have written records of any other gearbox leakage before 2005, but verbal discussions with operators suggest that it has been a growing problem for at least 20 years, and possibly longer. Some time before 2007, it was thought that gearbox oil pooling under the exhaust volute had caused a fire. However, when Alba Power inspected the unit later that year, it was noted that the fire had been the result of leaking fuel oil from failed start attempts on the Avon.

In March 2010, there was a fire under the exhaust stack, and the events following this fire are fully documented in NL Hydro's "Sequence of Events Report" which is included in Appendix 2. The fire caused justifiable safety concern with the operators, and it was reported to the Provincial Department of Occupational Health and Safety, who imposed an operating restriction on the unit.

Alba Power was asked to review and repair the lube oil system and a number of oil leaks were eliminated or reduced:

- Leaks in the auxiliary lube oil piping around the AC, DC and shaft driven pumps were re-gasketed, with the leakage eliminated.
- A new set of seals were manufactured for the generator end of the power turbine gearbox and a large temporary containment dish was installed under this leaking seal. This reduced leakage to what Alba described as "an acceptable level"
- Oil was weeping from the top of the power turbine casing, an instrumentation line and the aux trip bolt mechanism. Repairs eliminated these leaks

After 12 hours of operation at 10 MW, smoke was still seen coming from the top of the gas turbine gearbox in the vicinity of the stack. NL Hydro staff assumed that the seal on the front of the high speed gearbox shaft was also leaking. While a prudent assumption, it is possible that any front end leakage may actually come from another location. The unit has not operated since.

The only conclusions which could be drawn from AMEC's site visit, when the unit was not operating and was fully assembled, were:

- The only visible evidence of fire is a relatively small black charred area above the gearbox on the exhaust volute.
- The existing fire detection equipment is inadequate and did not detect the 2010 fire.
- No ignition source has yet been determined.
- While the new Inergen fire suppression system is safe for operators, it may not be capable of extinguishing an oil fire in the GT compartment, as presently configured, because of the large flow of ventilation air in the compartment. Given that the compartment should be unmanned

during operation, the fire detection and suppression systems should be capable of detecting and controlling fires without the entry of Hydro operating personnel. The overall fire detection and fire protection status of the unit should be reviewed in detail.

At least three or four causes have been suggested for the labyrinth oil seal leakage at the generator end (low speed shaft) and drive end (high speed shaft). There is some evidence to support two of the leakage mechanisms, which may compound each other. The principal causes which have been proposed are:

1. The seal between the power turbine shaft and the front bearing support structure (which is an extension of the gearbox casing) is a double labyrinth which is sealed in the middle by air taken from an Avon compressor bleed. Alba noted, in their May 2007 report, that the pressure in the gearbox (measured by a gauge mounted on the gearboxes casing) rises with load and have suggested that the gearbox is being pressurized by the Avon bleed air. At a load of 10 MW the pressure in the gearbox was 3 inches water gauge. Alba tried to resolve this by adding another oil tank vent, which appeared to reduce the leakage.

   This problem has occurred on other gas turbines and one of the upgrade options offered by GE for their Frame 5 and 6 units, with outputs of 17.5 MW to 40 MW, is to install an oil tank vent blower with coalescer, which maintains a small vacuum in the gearbox and coalesces the oil taken from the tank and returns it via a drain.

2. The bearings may have suffered severe wear due to a number of possible causes (misalignment, gear backlash, or low gearbox oil pressure). In 2008, Alba noted that the splash plate behind the generator end seal was making contact with the shaft, which indicates heavy bearing wear.
3. Misalignment has been proposed as a cause of the leakage, but there is no direct evidence of this.
4. The rear labyrinth seal appears, from the limited data available to us, to be too short. An ideal labyrinth seal should have at least 3 labyrinth sections with oil drains between the sections. The existing seal seems to have only two sections with no oil drain.

Generator and Exciter

The Generator, Exciter, AVR and controls were standard at the time of their installation. There has been no major maintenance on the generator or the exciter since 1986. NL Hydro established a draft maintenance procedure in 2009, which included performing insulation integrity tests every second year on both the generator and exciter (resistance to ground, polarization, and resistance phase to phase). The trends of these readings can mean as much as the absolute values, but no figures for them were available before the Siemens tests of 2011.

2.1.4 Condition Assessment & Remaining Life

GTG Gas Generator

It is now industry practice to specify the overhaul life of a gas turbine in terms of “Hot end overhauls”, during which the high temperature components such as the combustors and turbine blading are refurbished or replaced and “Major maintenance overhauls”, where the hot end and other components are repaired or replaced. The most expensive element of gas turbine maintenance is normally the replacement of high temperature components, and on newer machines this represents up to half of the total cost of a major overhaul. Many high temperature components may have an expected life between refurbishment of over 20,000 hours but can be refurbished one or more times.

The Avon overhaul life was originally established as 1500 hours in peaking mode and up to 8000 hours at base load. With experience, these figures were increased to 4000/5000 for peak load and 25,000/30,000 for base load.

Rolls Royce (RR) now does not directly support older Avon units but there are a number of experienced companies providing support. These companies do not generally differentiate between "Hot end" and "Major" overhauls but offer "Standard overhauls". It is expected that all of the parts of Avon can be replaced because parts for the Mk-1533 Avon units are plentiful and generally inexpensive. Avon turbine blading has relatively simple metallurgy and cooling arrangements, so it is inexpensive compared to the blading of newer gas turbines.

It is difficult to determine how much of its overhaul life the Avon has expended. All of the recent boroscope reports suggest that it is in reasonable condition, but none of the turbine components have been replaced in the last 20 years, according to our records, and the HP turbine blading and IP vanes have not been replaced or refurbished for over 25 years .

The unit was examined by Rolls-Woods in Nov 2010 and Alba power in 2009 and a summary of their findings is provided below:

- Rolls Woods state that generally the engine appears to be in reasonably good and serviceable condition. The compressor stator components, compressor stators, bleed valves and outer casing were all in reasonably good condition, with most components showing some loss of coating and light corrosion. Components that have deteriorated in the past, such as the front bearing housing and IGV bushings appear to be in good condition. Hot end components also appear to be in good condition with minimal visible damage.
- Alba report that the Avon is in good condition, but are concerned about the loss of coatings, especially on the compressor. It is their opinion that further loss of coating may damage components to the point that they cannot be refurbished.

Normally, the overhaul life of a peaking unit is influenced most by high temperature fatigue while a base load unit is normally limited more by creep, oxidation and corrosion. Boroscope inspections give only limited data on fatigue and creep life expenditure. It is possible that the unit may have operated at its Peak output, earlier in its history, as there are signs of overheating in some of the generator coils (although these could be the result of phase imbalances). Because the engine is rarely washed and has extensive corrosion and pitting, it is likely to have suffered significant performance degradation, which might have reduced its output by up to 10%. (some early US navy gas turbines suffered up to 15% output degradation). The base load output of a degraded unit at high ambient temperatures, would be below 8 MW and the operators may unwittingly have operated at peak, at some time in the unit's 45 year history.

Our estimate of the Avon's equivalent operating hours is shown in Table 2-4, below.

The time between overhauls for the existing Avon unit, which are nominally 8,000 hours at peak load and 25,000/30,000 at base load, have to be adjusted for 5 factors, discussed below:

- Between 30 and 40 years ago, Rolls Royce introduced a starts factor making each start equivalent to 10 hours of operation. This factor is somewhat subjective. Most large modern aeroderivative units do not have such a factor, and the manufacturers claim that the number of starts has little effect on overhaul life, if starts are limited to a reasonable number. RR's current guidance on the Avon is that the equivalence factor is dependent on the type of fuel and the ratio of hours per start. Given that the Holyrood machine burns liquid fuel and has an operating hours to starts ratio of below 3, each start should be counted as ten hours of base load maintenance life.

- The unit operates in a very high salt environment and during the first 19 years of its operating life, and the last five or more years, it has had inadequate inlet filtration. This has affected the compressor blading and casing more than the turbine. There has been a significant loss of compressor coatings.
- The unit operates for very few hours per year. There is little data on how this influences maintenance life, but at Holyrood it seems to have had little effect.
- The unit burns distillate which reduces maintenance life when compared to natural gas.
- The Avon is a very early unit, without many of the later modifications introduced to increase overhaul life.

TABLE 2-4 CALCULATION OF EQUIVALENT OPERATING HOURS

	Equivalent operating hours since 1991	Total equivalent operating hours
Components affected	HP vanes, IP turbine blading, misc other	Many components have never been refurbished
Operating hours	2,000 approx	4,700
Hours equivalent of starts @ 10 hrs per start	14,000	25,000
Discount for oil fuel. Typically 25% adder on other gas turbine types	4,000	7,425
Discount for corrosion	See note below	See note below
Approximate totals	20,000 plus	38,000 plus

Note on Corrosion: Corrosion appears to have affected the compressor blading and casing more than the turbine. Given that compressor components should have a longer operating life than the turbine, corrosion may not be the key factor in determining overhaul life. Also salt appears to have affected the coatings on the compressor more than those of the turbine . The former are designed to protect the blades, while turbine coatings reduce heat flux and protect the rotor and disk from excessive temperatures. We note that the turbine rotor was replaced before 1986.

The data which is available to AMEC suggests that most of the turbine components are original, with the exception of HP nozzle blades and IP turbine blades. On the Avon the turbine nozzles usually suffer more deterioration than the moving blades. Table 2-4 suggests that, as a minimum, the HP turbine blading and IP nozzles may require refurbishment.

There are many other components on the Avon which cannot be seen during a boroscope inspection, so their condition is unknown.

The Avon requires an overhaul to replace coatings and repair or replace turbine blading and other components which have suffered cracking or other damage. It is expected that when the Avon has been overhauled and the inlet filters replaced, it will not require a further significant overhaul before life end in 2020. In addition, the future annual maintenance costs would be less than $10,000 per year.

Power Turbine

The power turbine has received little attention since 1986. A boroscope photograph from 2011 is the only one that we have seen that shows the power turbine blading roots. This shows only a small number of blade roots but the disk material in the axially serrated root appears to be severely corroded. The photos do not show the bulk of the disk itself so we have no way of knowing if this corrosion is present on the remainder of the disk, and whether it is superficial or deep. In the photo, it appears to extend under the root. Steam turbines can suffer from blade root corrosion caused by materials collecting in the root, and it is possible that salt particles have collected in the complex root form. The corrosion may be more serious in highly stressed areas, such as the root. Alternatively, the whole disk may be corroded. In either case, the roots are very vulnerable to stress corrosion cracking.

It should be noted that the turbine cooling air is taken directly from the environment, without filtration. Cooling air passes through an ejector, using Avon bleed air, so that the air reaching the disk is a mixture of filtered air from the Avon and unfiltered air. The disk cooling system has probably operated for 45 years with a significant salt loading.

The Power turbine disk material is a low alloy ferritic steel selected for its high transition temperature. It seems likely that such a material has a service limit of 535 C or lower. The Avon exhaust cone temp (ECT) is close to 640 deg C at the full peak rating, so clearly the design of the API depends on effective disk and blade root cooling. It is probable that the blade root is highly stressed at full load, even with its design cooling. The axially serrated root was the most expensive blade root used by AEI, and so they only used it for highly stressed locations.

Greenray, who now legally represent AEI gas turbines and hold all rights to their technology, do not think that the power turbine should be operated in its present condition, and AMEC agrees with this recommendation.

Based on the information available to AMEC, it appears that the turbine disk should be replaced, using most or all of the existing moving blades. Welding repairs are required on the inlet cones, struts, heat shield, etc and can be used for slightly damaged blades. The cooling air system should be examined carefully as it is essential for the integrity of the power turbine disk and blading. With these measures, there should be no problem operating the power turbine for another ten years or more. The highest risk is the loss of a diaphragm or moving blade.

Gearbox

The gearbox pinion and wheel were examined briefly by Alba in 2007 and appeared to be in good condition at that time. A gearbox of this type should operate for many years without problem, and if the bearings and seals are replaced, the gearbox should not present a large risk. The cause of the low oil pressure from the mechanical pump and the oil leak on the low speed drive shaft must be determined and rectified. Although the high speed gearbox shaft has more complex labyrinth seals than those of the generator end, and an air seal, it is probably prudent to assume that this seal is also leaking.

The only conclusions which could be drawn from AMEC's site visit, when the unit was not operating and was fully assembled, were:

- The only visible evidence of fire is a relatively small black charred area above the gearbox on the exhaust volute.
- The existing fire detection equipment is inadequate and did not detect the 2010 fire.
- No ignition source has yet been located.

- While the new Inergen fire suppression system is safe for the operators, it is important to confirm that it is capable of extinguishing an oil fire in the GT compartment, as presently configured, and with all ventilation is shut off in the event of a fire. Given that the compartment should be unmanned during operation, the fire detection and suppression systems should be capable of detecting and controlling fires without the entry of Hydro operating personnel. The overall fire detection and fire protection status of the unit requires a detailed review.

At least three or four causes have been suggested for the labyrinth oil seal leakage at the generator end (low speed shaft) and drive end (high speed shaft). There is some evidence to support two of the leakage mechanisms, which may complement each other. The principal causes which have been proposed are:

a. The seal between the power turbine shaft and the front bearing support structure (which is an extension of the gearbox casing) is a double labyrinth which is sealed in the middle by air taken from an Avon compressor bleed. Alba noted, in their May 2007 report, that the pressure in the gearbox (measured by a gauge mounted on the gearboxes casing) rises with load and they suggested that the gearbox is being pressurized by the Avon bleed air. At a load of 10 MW the pressure in the gearbox was 3 inches water gauge. Alba tried to resolve this by adding another oil tank vent, which appeared to reduce the leakage.

   This problem has occurred on other gas turbines and one of the upgrade options offered by GE for their Frame 5 and 6 units, with outputs of 17.5 MW to 40 MW, is to install an oil tank vent blower with coalescer, which maintains a small vacuum in the gearbox and coalesces the oil taken from the tank and returns it via a drain.

b. The bearings may have suffered severe wear due to a number of possible causes (misalignment, gear backlash, or low gearbox oil pressure). In 2008, Alba noted that the splash plate behind the generator end seal was making contact with the shaft, which indicates heavy bearing wear.
c. Misalignment has been proposed as a cause of the leakage, but there is no direct evidence of this. Another GE upgrade on older gas turbine models is an improved flexible coupling between gas turbine and the load gear.
d. The rear labyrinth seal appears, from the limited data available to us, to be too short. An ideal labyrinth seal should have at least 3 labyrinth sections with oil drains between the sections. The existing seal seems to have only two sections with no oil drain.

Both Alba Power and Greenray, have quoted for the repair of the gearbox, and the bids of both of these companies suggest that the problem can be resolved by restoring the unit to its original design, with better venting. The adequacy of this proposed repair is reinforced by the fact that the Newfoundland Power Commission API unit at Salt Pond has not suffered from oil leaks, and that both Alba and Greenray have experience of other API units.

Since 1991, NL Hydro has arranged for a boroscope inspection at regular intervals, but the unit has not left the site. On each of the six inspections between 1999 and 2006, the inspection reports indicated that the unit appeared satisfactory. A number of minor repairs have been made since 1991, including replacement of IGV bushings and IGV rams, tightening of nuts, and replacement of minor components. However, no major gas path component was replaced until 2009, when the combustor cans were replaced.

GTG Inlet Plenum

It is clear that in the high saline atmosphere at Holyrood, operating with an increasingly ineffective inlet filter, the unit has suffered considerable degradation during very few hours of operation. For example, Alba Power reported that between May 2007 and June 2008, the unit had only ran 26 hours with 54 starts and there was considerable degradation of the combustors and other components, which may have corresponded to less than one month of operation in a normal base load unit. The unit is rarely washed because washing is normally performed largely to maintain efficiency. However, it would be beneficial to wash the Holyrood unit because of the buildup of salt on the first stages of the compressor. At present, the engine shows signs of pitting, salt deposition, corrosion and loss of coatings on the Avon gas generator. There is also cracking in the turbine section.

Without replacement, the Avon and PT will degrade rapidly. The inlet air filter/media should be replaced and/or brought back to reasonable condition.

Generator

Siemens inspected the generator in 2011 and performed (resistance to ground tests (megger), polarization index of machine windings, and phase to phase resistance measurements. They also visually inspected the stator laminations, windings, and the rotor.

The generator has only 4700 operating hours and NL Hydro records show that in recent years, it has rarely operated at above 10 MW. It is rated 14.15 MW. It should have a design life of over 40 years, but its insulation has suffered from age and possibly from rapid thermal cycling and condensation. The API unit can start and ramp to full load in about 2 minutes and during a fast start, the coils will suffer some thermal stress. Also, the unit experiences large temperature differences between the windings and the cooling air. There are no anti-condensation heaters. If the generator had operated with a high capacity factor for 45 years it would likely require a rewind.

Siemen's report shows that the insulation has deteriorated and there is a phase imbalance on the stator. Siemens recommend rewinding the stator. Table 2-5 compares the measured test results of the generator, exciter and major motors. The polarization readings of the generator stator are reasonable, and considerably better than those of the Exciter stator and the major motors. However the stator phase imbalance is quite high and the cost of a stator rewind has been included in the refurbishment estimate.

TABLE 2-5 COMPARISON OF SIEMENS TEST RESULTS ON GENERATOR AND MOTORS

	Resistance to Ground @ 1 Minute M ohm	Polarization of Windings	Phase to Phase Resistance
Generator Stator	534	1.93	30% imbalance
Generator Rotor	2.67	1.1	
Exciter Stator	534	.96	
Exciter Rotor	2060	2.14	Within 0.7%
AC Oil Pump Motor	4600	1.15	Within 0.17%
DC Oil Pump Motor	185	0.93	
AC Lube Oil Cooler Fan	5520	1.37	Within 0.67%
Fuel Oil Motors	7920/1250	1.56/0.95	Within 0.18%

Generator Exciter

Siemens recommended an overhaul of the exciter, but there is some concern that an overhaul is not practical because the 45 year old unit is no longer supported by the OEM. Parts may not be available. On the other hand, it may be difficult to support the purchase of a new unit for a 8 year life extension.

Summary

In general, the unit is currently in poor condition and overdue for a major overhaul of many components. A tabular summary of the condition assessment of the gas turbine genset is provided below in Table 2-6:

TABLE 2-6 CONDITION ASSESSMENT – GAS TURBINE GENSETS

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset Level 3	Description	Detail	Cond. Summ. ID#	Condition	Status Identifier	Original Life (Base Load) Ops Hrs (Yrs)	Current Expected Minimum Remaining Life Years (Subject to Test)	End of Life (EOL) Required	Capability to Reach EOL	In Service
1273	7202	0	0	GAS TURBINE SYSTEM	GAS TURBINE SYSTEM		GTG1	44 years old and has accumulated to 2010 about 4,717 hours with 1,548 starts. Four significant overhauls/repairs in 1978, 1986, and 1991 and a combustor replacement in 2007	4/10	150,000 (30)	1	2020	No	1969
1273	7202	7308	0	GAS TURBINE AVON JET ENGINE	GAS TURBINE AVON GAS GENERATOR	General	GTG2	Overall Rolls Wood group inspection in 2010 concluded that the engine appears in reasonably good and serviceable condition.The engine shows signs of pitting, salt deposition, corrosion and loss of coatings on the Avon gas generator. Coatings and some turbine blading and other components have suffered cracking or other damage. Corrosion/cracking from seaside moisture and starts. Buildup of salt on the first stages of the compressor. There is also cracking in the turbine section. Overdue for overhaul.Rear bearing housing in good condition..	4/10	150,000 (30)	2	2020	No	1969
1273	7202	7058	0	GAS TURBINE AVON JET ENGINE	GAS TURBINE AVON GAS GENERATOR	Compressor and Intake	GTG3	Rolls Wood reported: front bearing housing in good condition with medium loss of coating and corrosion,; VIGV bushes in good condition;bleed valves in good condiion, compressor stators in good clean condition with no defects; compressor casing surfaces in reasonably good condition with light to medium loss of coating and corrosion in some areas; compressor outlet casing in good condition with OGV having minor to medium loss of coating and corrosion to most surfaces;	4/10	150,000 (30)	2	2020	No	1969
1273	7202	7058	0	GAS TURBINE AVON JET ENGINE	GAS TURBINE AVON GAS GENERATOR	Combustor	GTG4	Rolls Wood reported: carbon deposits on head sections and streaks down flame tube length;All in good conddition.	4/10	150,000 (30)	10	2020	Yes	2008
1273	7202	7058	0	GAS TURBINE AVON JET ENGINE	GAS TURBINE AVON GAS GENERATOR	Turbine Rotor	GTG5	Rolls Wood reported: HP,IP andLP turbine blades intact and free of obvious defects. Exhaust assembly in good condition with minor surface corrosion.	4/10	150,000 (30)	5	2020	No	1969
1273	7202	7058	0	GAS TURBINE POWER TURB & G/B	GAS TURBINE POWER TURBINE	Power Turbine	GTG6	Received little attention since 1986 with very limited boropscope views of blade roots. Disk material in these limited views in the axially serrated root appears to be severely corroded.No way of knowing if corrosion is present on the remainder of the disk, and whether superficial or deep. Appears to extend under the root. It is possible that salt particles have collected in the complex root form. The corrosion may be more serious in highly stressed areas, such as the root. Alternatively the whole disk may be corroded. In either case the roots are very vulnerable to stress corrosion cracking.Overdue for overhaul. Greenray (legal representive of AEI gas turbines, hold all rights to their technology)do not think that the power turbine should be operated in its present condition.	4/10	150,000 (30)	2	2020	No	1969
1273	7202	7058	0	GAS TURBINE POWER TURB & G/B	GAS TURBINE POWER TURBINE	Power Turbine	GTG7	Greenray in its 2011 inspection noted: several circumferential cracks on inlet duct iner cone (previously seen in 2006) - no/limited propogation apparent; weld repairs on cone spokes inner downstream edges may be starting to fail; nozzle blade track corroded, heavily in places, and could cause failure of nozzle segment and shroud; blade tps irregular,possibly rubbed (little other evidence of blade tip rub); geneal corrosion (most light) on blading; rotor disc fir tree posts (for blades) heavily corroded in visible areas highly stressed areas - fialure could lead to catastrophic effect on power turbine components and appear to be propogating under rotor blade shoulder which could cause premature failure.; diffuser/volue generally corroded - effect on volute welding.	4/10	150,000 (30)	2	2020	No	1969
1273	7202	7058	0	GAS TURBINE POWER TURB & G/B	GAS TURBINE POWER TURBINE	Cooling Air	GTG8	Turbine cooling air is taken directly from the environment, without filtration. Cooling air passes through an ejector, using Avon bleed air, so that the air reaching the disk is a mixture of filtered air from the Avon and unfiltered air. The disk cooling system has probably operated for 45 years with a significant salt loading.	4/10	150,000 (30)	2	2020	No	1969
1273	7202	7058	0	GAS TURBINE POWER TURB & G/B	GAS TURBINE POWER GEARBOX	Gearbox	GTG9	Alba in 2007 indicated gearbox appeared to be in good condition and that if the bearings and seals are replaced the gearbox should not present a large risk. Issues remain on the cause of the low oil pressure from the mechanical pump and the oil leak on the low speed drive shaft and must be determined and rectified. The high speed gearbox shaft seals are leaking and were the cause of a 2010 fire at the power turbine end of the gearbox which has resulted in the unit being limited to emergency use only. At least three or four causes have been suggested for the labyrinth oil seal leakage at the generator end (low speed shaft) and drive end (high speed shaft). Tests on the pressure in the gearbox (measured by a gauge mounted on the gearboxs casing) showed a rise with load and suggested that the gearbox is being pressurized by the Avon bleed air. Greenray 2011 inspection: Gear wheels and internals appeared in pristne condition with normal marks. Outer wiper of leaking low speed gear wheel lube oil gland may be touching top of shaft and have some clearance at bottom (opposite to normal) and may indicate driven machine out of alignment with gearbox output shaft The bearings may have suffered severe wear due to a number of possible causes (misalignment, gear backlash, or low gearbox oil pressure). In 2008 Alba noted that the splash plate behind the generator end seal was making contact with the shaft, which indicates heavy bearing wear. Overdue for overhaul.	4/10	150,000 (30)	2	2020	No	1969
1273	7202	7309	0	GAS TURBINE GENERATOR	GAS TURBINE GENERATOR	Generator	GTG10	Siemen's report shows that the insulation has deteriorated and there is a phase inbalance on the stator. The polarization readings of the generator stator are reasonable, and considerably better than those of the Exciter stator and the major motors. However the stator phase inbalance is quite high. The generator compartment was provided with new filter elements which are in good condition, except that there are some holes in the building siding that allows some air to bypass them.	4/10	200000 (40)	5	2020	No	1969
1273	7202	7309	0	GAS TURBINE GENERATOR	GAS TURBINE GENERATOR	Generator	GTG11	Siemen's report rotor appears in good condition, that stator iron and wedging in good condition, some stator coil overheating, Stator insulation appeared dregraded, dry and flaking throughout,	4/10	200000 (40)	5	2020	No	1969
1273	7202	7311	0	GAS TURBINE AUXILIARY SYSTEMS	GAS TURBINE EXHAUST STACK	Exhaust Stack	GTG12	Severly corroded, leaking,Braden 2011 inspection: exterior significant carbon steel crystallization and peeling of carbon steel; no fatigue/cracking of welds, sulging of stack on south side, several holes in exhaust. Snow hood no apparent issues (some operation issues with functionality). Transition duct (external insulation) not visible for inspection. Expansion joint belt in good condition. reported	4/10	(20)	1	2020	No	1986
1273	7202	7311	99003602	GAS TURBINE AUXILIARY SYSTEMS	GAS TURBINE AIR INLET PLENUM CHAMBER & MEDIA	Filter Material	GTG13	Inlet housing and filtration system were replaced in 1986. Its stainless steel inlet splitters appear to have suffered little deterioration Water leaking into plenum.Filter media is considered inappropriate for its marine environment. The filter now has air gaps between the filter elements, due to rusting The high saline atmosphere means that the unit is operating with an increasingly ineffective inlet filter and the unit has suffered considerable degradation.	4/10	(30)	2	2020	No	1986
1273	7202	7311	99003602	GAS TURBINE AUXILIARY SYSTEMS	GOVENOR & FUEL CONTROL		GTG14	No specific informatioon on govenor and fuel control. Fuel control was an issue in 2007 Alba report with a recommendation to upgrade to address failed starts due to fuel control. Appears to have been completed..	4/10	(30)	5	2020	No	1986/2008
1273	7202	7311	99003602	GAS TURBINE AUXILIARY SYSTEMS	EXCITATION SYSTEM		GTG15	Siemens recommended an overhaul of the exciter and steam cleaning of windings, VPI testing of insulation. There is some concern that it is a 45 year old unit which is not supported. The polarization readings of the Exciter stator are poor.	4/10	(30)	2	2020	No	1986

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

2.1.5 Risk Assessment

TABLE 2-7 RISK ASSESSMENT – GAS TURBINE GENSETS

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset Level 3	Description	Detail	Cond. Summ. ID#	Condition	Major Issues	Remaining Life Years	TECHNO-ECO RISK ASSESS MODEL			SAFETY RISK ASSESS MODEL			Possible Failure Event	Mitigation
										(Insufficient Info - Inspection Required Within (x) Years)	Likeli--hood	Conse-quence	Risk Level	Likeli-hood	Conse-quence	Safety Risk		
1273	7202	0	0	GAS TURBINE SYSTEM	GAS TURBINE SYSTEM		GTG1	44 years old and has accumulated to 2010 about 4,717 hours with 1,548 starts. Four significant overhauls/repairs in 1978, 1986, and 1991 and a combustor replacement in 2007	Major systems need overhaul	1/10	4	C	High	3	D	High	Major/catastrophic failure of unit or fire	Overhaul or replace
1273	7202	7308	0	GAS TURBINE AVON JET ENGINE	GAS TURBINE AVON GAS GENERATOR		GTG2	Overall Rolls Wood group inspection in 2010 concluded that the engine appears in reasonably good and serviceable condition.The engine shows signs of pitting, salt deposition, corrosion and loss of coatings on the Avon gas generator. Coatings and some turbine blading and other components have suffered cracking or other damage. Corrosion/cracking from seaside moisture and starts. Buildup of salt on the first stages of the compressor. There is also cracking in the turbine section. Overdue for overhaul.Rear bearing housing in good condition..	Blade failure or material realease causes downstream collateral damage.	2	3	C	Medium	1	D	Medium	Catastrophic failure of downstream equipment	Overhaul or replace
1273	7202	7058	0	GAS TURBINE POWER TURB & G/B	GAS TURBINE POWER TURBINE	Power Turbine	GTG6/7	Received little attention since 1986 with very limited boropscope views of blade roots. Disk material in these limited views in the axially serrated root appears to be severely corroded.No way of knowing if corrosion is present on the remainder of the disk, and whether superficial or deep. Appears to extend under the root. It is possible that salt particles have collected in the complex root form. The corrosion may be more serious in highly stressed areas, such as the root. Alternatively the whole disk may be corroded. In either case the roots are very vulnerable to stress corrosion cracking.Overdue for overhaul. Greenray (legal representive of AEI gas turbines, hold all rights to their technology)do not think that the power turbine should be operated in its present condition.	Power turbine rotor disck high stress blade root failure	2	4	C	High	3	D	High	Blade root failure of disk - catastrophic faiure	Replace/repair disk and overhaul unit.
1273	7202	7058	0	GAS TURBINE POWER TURB & G/B	GAS TURBINE POWER TURBINE	Power Turbine	GTG8	Turbine cooling air is taken directly from the environment, without filtration. Cooling air passes through an ejector, using Avon bleed air, so that the air reaching the disk is a mixture of filtered air from the Avon and unfiltered air. The disk cooling system has probably operated for 45 years with a significant salt loading.	Corrosion of power turbine blade roots.	2	4	C	High	3	D	High	Blade root failure of disk - catastrophic faiure	Modify air inlet. Replace/repair disk and overhaul unit.
1273	7202	7058	0	GAS TURBINE POWER TURB & G/B	GAS TURBINE POWER GEARBOX	Gearbox	GTG9	Alba in 2007 indicated gearbox appeared to be in good condition and that if the bearings and seals are replaced the gearbox should not present a large risk. Issues remain on the cause of the low oil pressure from the mechanical pump and the oil leak on the low speed drive shaft and must be determined and rectified. The high speed gearbox shaft seals are leaking and were the cause of a 2010 fire at the power turbine end of the gearbox which has resulted in the unit being limited to emergency use only. At least three or four causes have been suggested for the labyrinth oil seal leakage at the generator end (low speed shaft) and drive end (high speed shaft). Tests on the pressure in the gearbox (measured by a gauge mounted on the gearboxs casing) showed a rise with load and suggested that the gearbox is being pressurized by the Avon bleed air. Greenray 2011 inspection: Gear wheels and internals appeared in pristne condition with normal marks. Outer wiper of leaking low speed gear wheel lube oil gland may be touching top of shaft and have some clearance at bottom (opposite to normal) and may indicate driven machine out of alignment with gearbox output shaft The bearings may have suffered severe wear due to a number of possible causes (misalignment, gear backlash, or low gearbox oil pressure). In 2008 Alba noted that the splash plate behind the generator end seal was making contact with the shaft, which indicates heavy bearing wear. Overdue for overhaul.	Gearbox oil leaks; gearbox misalignment/wear	2	4	C	High	3	D	High	Lube oil fires. (Gearbox failure (bearings/misalgnment)	Gearbox overhaul - seals, alignment, bearings
1273	7202	7309	0	GAS TURBINE GENERATOR	GAS TURBINE GENERATOR		GTG10/11	Siemen's report shows that the insulation has deteriorated and there is a phase inbalance on the stator. The polarization readings of the generator stator are reasonable, and considerably better than those of the Exciter stator and the major motors. However the stator phase inbalance is quite high. The generator compartment was provided with new filter elements which are in good condition, except that there are some holes in the building siding that allows some air to bypass them.	Generator insulation condiion and potential for failure	5	3	C	Medium	3	C	Medium	Generator winding failure and collateraldamage	Generator overhaul. Rewinds if necessary.
1273	7202	7311	0	GAS TURBINE AUXILIARY SYSTEMS	GAS TURBINE EXHAUST STACK	Exhaust Stack	GTG12	Severly corroded, leaking,Braden 2011 inspection: exterior significant carbon steel crystallization and peeling of carbon steel; no fatigue/cracking of welds, sulging of stack on south side, several holes in exhaust. Snow hood no apparent issues (some operation issues with functionality). Transition duct (external insulation) not visible for inspection. Expansion joint belt in good condition. reported	Stack water leakage into power turbine	1	4	C	High	3	C	Medium	Power turbine corrosion/failure. Stack failure	Replace stack
1273	7202	7311	99003602	GAS TURBINE AUXILIARY SYSTEMS	GAS TURBINE AIR INLET PLENUM CHAMBER & MEDIA	Filter Material	GTG13	Inlet housing and filtration system were replaced in 1986. Its stainless steel inlet splitters appear to have suffered little deterioration Water leaking into plenum.Filter media is considered inappropriate for its marine environment. The filter now has air gaps between the filter elements, due to rusting The high saline atmosphere means that the unit is operating with an increasingly ineffective inlet filter and the unit has suffered considerable degradation.	Corrosion impact on gas generator and power turbine causing failure	2	3	C	Medium	3	C	Medium	Corrosion of gas generator and power turbine accelerates.	Replace filter media; overhaul/repair housing.
1273	7202	7311	99003602	GAS TURBINE AUXILIARY SYSTEMS	GOVENOR & FUEL CONTROL		GTG14	No specific informatioon on govenor and fuel control. Fuel control was an issue in 2007 Alba report with a recommendation to upgrade to address failed starts due to fuel control. Appears to have been completed..	Failed starts and speed/load control	5	2	B	Low	2	B	Low	Unit start and control	Check status and refurbish as required as part of overhaul.
1273	7202	7311	99003602	GAS TURBINE AUXILIARY SYSTEMS	EXCITATION SYSTEM		GTG15	Siemens recommended an overhaul of the exciter and steam cleaning of windings, VPI testing of insulation. There is some concern that it is a 45 year old unit which is not supported. The polarization readings of the Exciter stator are poor.	Exciter failure; unit extended outage.	2	3	C	Medium	3	C	Medium	Failure of exciter leads to extended shutdown of unit.	Replace exciter.

2.1.6 Actions

TABLE 2-8 ACTIONS – GAS TURBINE GENSETS

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset Level 3	Description	Detail	Cond. Summ. ID#	Capital Item	Date	Priority
1273	7202	0	0	GAS TURBINE SYSTEM	GAS TURBINE SYSTEM		GTG1			
1273	7202	7308	0	GAS TURBINE AVON JET ENGINE	GAS TURBINE AVON GAS GENERATOR	General	GTG2	No specific capital projects - major unit overhaul.	2012	1
1273	7202	7308	0	GAS TURBINE AVON JET ENGINE	GAS TURBINE AVON GAS GENERATOR	Compressor and Intake	GTG3	No specific capital projects - major unit overhaul.	2012	1
1273	7202	7308	0	GAS TURBINE AVON JET ENGINE	GAS TURBINE AVON GAS GENERATOR	Combustor	GTG4	No specific capital projects - major unit overhaul.	2012	1
1273	7202	7308	0	GAS TURBINE AVON JET ENGINE	GAS TURBINE AVON GAS GENERATOR	Turbine Rotor	GTG5	No specific capital projects - major unit overhaul.	2012	1
1273	7202	7058	0	GAS TURBINE POWER TURB & G/B	GAS TURBINE POWER TURBINE	Power Turbine	GTG6/7	Purchase power turbine disk. No other specific capital projects - major unit overhaul.	2012	1
1273	7202	7058	0	GAS TURBINE POWER TURB & G/B	GAS TURBINE POWER TURBINE	Cooling Air	GTG8	Modify cooling air to power turbine to eliminate salt ingress - part of major unit overhaul.	2012	1
1273	7202	7058	0	GAS TURBINE POWER TURB & G/B	GAS TURBINE POWER GEARBOX	Gearbox	GTG9	No specific capital projects - major unit overhaul.	2012	1
1273	7202	7309	0	GAS TURBINE GENERATOR	GAS TURBINE GENERATOR		GTG10/11	No specific capital projects - major unit overhaul.	2012	1
1273	7202	7311	0	GAS TURBINE AUXILIARY SYSTEMS	GAS TURBINE EXHAUST STACK	Exhaust Stack	GTG12	Replacement stack and installation	2012	1
1273	7202	7311	99003602	GAS TURBINE AUXILIARY SYSTEMS	GAS TURBINE AIR INLET PLENUM CHAMBER & MEDIA	Filter Material	GTG13	No specific capital Requirement - new fiolter media	2012	2
1273	7202	7311	99003602	GAS TURBINE AUXILIARY SYSTEMS	GOVENOR & FUEL CONTROL		GTG14	None		
1273	7202	7311	99003602	GAS TURBINE AUXILIARY SYSTEMS	EXCITATION SYSTEM		GTG15	Refurbish exciter (Replace as necessary in refurbishment)	2012	1

2.1.7 Life Assessment - Life Cycle Curves (Where equipment is not to be overhauled/replaced and life <2020 and has major unit operation impacts.)

The gas turbine *generator unit essentially requires all of its major components to be overhauled* or replaced as soon as practical. After such an overhaul, there should be no further major repairs required before 2020. Given this, no life cycle curves are presented for the gas turbine generator system.

2.1.8 Level 3 Inspections Required

The refurbishment of the unit can be done in two ways;

- NL Hydro can disassemble the unit and perform Level 3 inspection assessments on key equipment. After the assessments, NL Hydro will be able to obtain firm bids for replacement components and place orders for them. This will be a lengthy process and it will require Hydro to authorize a two phase investment; the first on disassembly and inspection and reassembly and the second for the purchase and fitting of replacement parts at some future date.
- Once NL Hydro makes a decision to refurbish the existing GT unit instead or replacing it with new GT or diesel generator facilities, those components identified as likely to require replacement should be ordered and the units overhauled. No level 3 inspections will be performed, although detailed inspections when during overhauls may show the need to refurbish other components. Large additional as-found overhaul costs are unlikely since a conservative approach in that any further major items will be required. Under this alternative independent Level 3 assessments are eliminated. This approach is recommended by AMEC.

Generally if the AMEC Recommended Approach is taken, no other “Level 3” inspections/tests are required.

If the first approach is taken, the most important Level 3 assessments are:

- Avon Gas Generator
- Power Turbine blade root condition
- Gearbox bearing wear/alignment and gearbox seals
- Disk cooling system

This approach may result in some savings in the final overhaul, but would require an additional outage and detailed inspections, and possibly additional delay in completing the final overhaul required.

2.1.9 Capital Enhancements

TABLE 2-9 SUGGESTED TYPICAL CAPITAL ENHANCEMENTS – GAS TURBINE GENSETS

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset Level 3	Description	Detail	Cond. Summ. ID#	Capital Item	Date	Priority
1273	7202	0	0	GAS TURBINE SYSTEM	GAS TURBINE SYSTEM		GTG1			
1273	7202	7308	0	GAS TURBINE AVON JET ENGINE	GAS TURBINE AVON GAS GENERATOR	General	GTG2	No specific capital projects - major unit overhaul.	2012	1
1273	7202	7308	0	GAS TURBINE AVON JET ENGINE	GAS TURBINE AVON GAS GENERATOR	Compressor and Intake	GTG3	No specific capital projects - major unit overhaul.	2012	1
1273	7202	7308	0	GAS TURBINE AVON JET ENGINE	GAS TURBINE AVON GAS GENERATOR	Combustor	GTG4	No specific capital projects - major unit overhaul.	2012	1
1273	7202	7308	0	GAS TURBINE AVON JET ENGINE	GAS TURBINE AVON GAS GENERATOR	Turbine Rotor	GTG5	No specific capital projects - major unit overhaul.	2012	1
1273	7202	7058	0	GAS TURBINE POWER TURB & G/B	GAS TURBINE POWER TURBINE	Power Turbine	GTG6/7	Purchase power turbine disk. No other specific capital projects - major unit overhaul.	2012	1
1273	7202	7058	0	GAS TURBINE POWER TURB & G/B	GAS TURBINE POWER TURBINE	Cooling Air	GTG8	Modify cooling air to power turbine to eliminate salt ingress - part of major unit overhaul.	2012	1
1273	7202	7058	0	GAS TURBINE POWER TURB & G/B	GAS TURBINE POWER GEARBOX	Gearbox	GTG9	No specific capital projects - major unit overhaul.	2012	1
1273	7202	7309	0	GAS TURBINE GENERATOR	GAS TURBINE GENERATOR		GTG10/11	No specific capital projects - major unit overhaul.	2012	1
1273	7202	7311	0	GAS TURBINE AUXILIARY SYSTEMS	GAS TURBINE EXHAUST STACK	Exhaust Stack	GTG12	Replacement stack and installation	2012	1
1273	7202	7311	99003602	GAS TURBINE AUXILIARY SYSTEMS	GAS TURBINE AIR INLET PLENUM CHAMBER & MEDIA	Filter Material	GTG13	No specific capital Requirement - new fiolter media	2012	2
1273	7202	7311	99003602	GAS TURBINE AUXILIARY SYSTEMS	GOVENOR & FUEL CONTROL		GTG14	None		
1273	7202	7311	99003602	GAS TURBINE AUXILIARY SYSTEMS	EXCITATION SYSTEM		GTG15	Refurbish exciter (Replace as necessary in refurbishment)	2012	1

2.1.10 Capital/Refurbishment and Overhaul Costs (Capital)

The Avon requires an overhaul to replace coatings and repair or replace turbine blading and other components which have suffered cracking or other damage. It is expected that when the Avon has been overhauled and the inlet filters replaced the Avon will not require further significant overhaul before life end in 2020, and that future annual maintenance costs would be less than $10,000 per year.

The first approach whereby limited funding is approved for disassembly and then make a second purchase decision when the equipment is examined is likely to be a slow process and possibly difficult administratively for NL Hydro. AMEC made assumptions based on data available, experience and recommendations from vendors such as Greenray, Alba Power, etc, and prepared an estimate covering all equipment which will probably be required for life extension. This is likely a quicker route to meet the project requirements, but has a risk of purchasing too much equipment.

AMEC received quotations from the following companies.

- Alba Power, Scotland.
- Greenray- the owner of AEI's original technology
- Camfil Farr- supplier of the inlet filter
- Braden - supplier of exhaust stacks
- SS Turbine services Ltd. - a small Canadian aero engine overhaul company.

In addition, AMEC has the quotation provided by 'Rolls Woods to NL Hydro for an Avon overhaul. This 2010 quotation is posted on Newfoundland Power Commission's website.

The pricing provided by Alba Power covers the entire plant, while other companies have only bid for their own equipment. The attached table shows the Alba Power bid, in column 1, with the bids from other companies in column 2. Column's 3 shows AMEC's estimate for the cost of providing a comprehensive rehabilitation to make the unit suitable for another 8 or more years of operation, with minimum risk. The major components, including the Avon, Power turbine, gearbox, generator, inlet filter and exhaust filter would be restored to the same condition as 1986. Column 3 is an amalgamation of the quotations received from the different companies, plus AMEC estimates for some minor costs.

The table assumes an exchange rate of 1.6 for the UK pound, and a modest 10% allowance for duty and freight.

Alba's cost of a complete "Standard Overhaul" of the Avon is included in column 3 but Alba did not include the cost of any required replacement parts. A full standard overhaul by Alba would therefore cost significantly more than the $500,000 which they bid, but it would give the Avon another 20,000 to 30,000 of life. S and S turbine have quoted $450,000 for a full overhaul including parts, which would include a proving test run after completion of the work. Even the work covered by this bid is probably excessive for the 8 year life extension required, but AMEC cannot judge how much work will be needed until the engine is disassembled. We have therefore allowed $500,000 for the Avon overhaul, including transportation.

Alba state that the unit will operate until 2020 with almost no additional cost, if the proposed overhaul is completed. In contrast to the comprehensive overhaul which Alba propose for the Avon, they have proposed simple on-site repairs of the inlet filter and exhaust stack, and a low cost overhaul of the generator and exciter.

TABLE 2-10 CAPITAL COST ESTIMATE $ 1,000 CDN$

	Option 1 Alba total package	Option 2 Split supply	Composite estimate	Comments
		Pound @ $1.6		
Avon	500		500	Alba estimate is for a complete standard overhaul. O/H reports suggest some of this is not required. (note 1)
Replacement components				Woods Rolls estimate $1.3 million for a complete Avon OH
				S and S turbine quote $450,000 including parts.
Power Turbine	300			
Disassemble/reassemble		136	75	Greenray estimate is substantially too high
New Disk		331	331	Alba also have a disk; no quotation provided yet.
Moving blades		See comment	93	1 blade incl Greenway price- See note 1
Rotor rehabilitation		282	282	Includes shipment to UK
Inlet structure repairs			15	Small amount of welding is required
Thermocouples				excluded from this estimate
Diaphragm section			40	
Heat shield				
Bearings		70	70	
Exhaust volute			30	Allow for minor repairs
Gearbox				
Bearings		114	114	
Disassemble/reassemble				
Inspect, crack detection				
Gearbox venting			25	Contingency against Greenray estimate
Contingency; 2nd opinion			25	Contingency against Greenray estimate
Generator and aux	87		900	Alba confident cleaning & varnishing will improvelife
				Rewind estimate requires confirmation.
Exciter			50	Refurbish (Replace as necessary during refurbishment)
Inlet filter	30	588	150	Camfil Farr est includes SS filter hours & new plenum.
				For 8 year life extension new plenum not required,
Exhaust stack	34	267	50	For 8 year life extens existing stack with refurb adequate.
Oil and fuel	45		0	This item covered by AMEC St Johns as BOP
Commission unit			50	
Contingency excl Avon			150	
TOTAL	996	1788	2951	

Note 1. Alba quote $500,000 excluding parts, but overhaul scope is very extensive and can be reduced. S & S turbine is a smaller shop but quote $450,000 including all required parts.
Note 2. New PT blades from Greenray are very expensive. These blades can be welded, and as efficiency is not important we have estimate is based on a total of 4 new blades and weld repairs to others.

Assume 10% duty and shipping

Schedule

The refurbishment of the unit can be done in two ways:

1. With the first alternative, NL Hydro can disassemble the unit in order to perform level 3 assessments on key equipment. After the Level 3 assessments, NL Hydro will be able to obtain firm bids for replacement components and place orders for them. This will be a lengthy process and it will require Hydro to authorize two separate contracts separated by several months. The first would cover disassembly and inspection and reassembly while the second would cover the purchase and fitting of replacement parts.

2. With the second alternative, AMEC will identify which components are likely to require replacement and that these are ordered if NL Hydro decides to refurbish the unit. Under this alternative, the unit will not receive any level 3 inspections until new components are available. It is possible that the detailed inspections will show the need for other component replacement, but AMEC thinks that it is unlikely that any further major long lead items will be required. The most expensive item which may have to be purchased is the power turbine disk, but NL Hydro will have the choice of purchasing a stock unit from Alba, if it is still available, or a new unit from Greenray.

The most important level 3 assessments are:

- Avon Gas Generator (The actual scope of the overhaul will be adjusted when the unit is inspected at the beginning of the overhaul).
- Gearbox and seals
- Power turbine Disk cooling system
- Power turbine disk
- Diaphragms and diaphragm ring

The schedule suggested by Greenway for the Power Turbine, with some additions identified for the other components, is shown in Table 2-11:

TABLE 2-11 HOLYROOD GT REFURBISHMENT SCHEDULE

Newfoundland and Labrador Hydro. Holyrood GT refurbishment

	week	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41
Manufacture Disc																																										
Strip and dissassemble plant																																										
Ship Rotor to overhaul plant																																										
Overhaul and balance Rotor																																										
Ship Rotor to Holyrood																																										
Rebuild and commission unit																																										
Avon overhaul																																										
Generator Refurbish (Rewind as necessary)																																										

2.2 Electrical & Controls Equipment/Processes

Unit #:	GAS TURBINE
Asset Class #	BU 1273 Gas Turbine
SCI & System:	7202 Gas Turbine System
Sub-Systems:	7310 HRD GT E&C

2.2.1 Description of Existing System

Holyrood GS consists of three thermal units (2x175 MW and 1x150 MW). Each unit supplies its own station service 4160V bus when on line. The Common station service for Unit #1 and #2 is fed from a 69KV/4160V 10.5/14MVA transformer SST-12. The Common station services of Unit #1 are fed from a 69KV/4160V 10.5/14MVA transformer SST-34. When the unit is shutdown (off line) its unit station service bus is transferred to the Common station services source (Reference - Holyrood Single Line Electrical Diagram).

During a total loss of all station service supply the station can be re-started from blackout condition with the 13.5 MW, 13.8 KV Emergency Gas Turbine (GT) connected to the 4160V station service bus through a 10.5 MVA step down transformer (T9). The station service buses all have a ground fault current limited to 1000A by a Neutral Ground Resister (NGR) of 2.4 Ohms.

References:

- NFL Holyrood Single Line Drawing # A)-1403-500-E-001 Rev 16
- IEEE C62.92-1989 Guide for the application of Neutral Grounding in Electrical Utility System Part II Grounding of Synchronous generator system.

Within the GT building, the Electrical and Control systems consist of a rotting brushless exciter, an automatic voltage regulator (AVR), a start rectifier, Distributed Control System (DCS) control modules, motor control centre (MCC), electronic governors, synchronizer, and protection and monitoring equipment.

The brushless exciter, AVR and start rectifier were manufactured by AEI Limited of Manchester, England in the mid-1960’s. The governor, synchronizer and monitoring equipment were newly installed in 1986. The exciter and AVR unit controls its stator terminal voltage (13.8 kV) and MVAr delivery. The start rectifier converts station AC current into the high DC current necessary to rotate the jet engine to ignition. The governor consists of two Woodward units: one that controls the jet acceleration on start-up and the second that controls the power turbine/generator during synchronization and megawatt (MW) loading. In 1987, the Gem 80/500 PLC replaced all relay logic, but in 2009 this was again replaced by a Foxboro (Invensys) system which is in communication with the Plant DCS, and is now the primary controlling medium for the gas turbine.

The excitation control system consists of a “Normal” and “Standby” automatic voltage regulator (AVR) backed up by a “Manual” control mode. The AVR controls the strength of the magnetic field in the exciter by varying the amount of current through the stationary exciter field windings.

Governor and Fuel Control: The standard Avon fuel control system is used without alteration as a basis for the API governing and fuel control system. The throttle valve is used as a generator valve and the HP cock as a fuel shut-off valve for normal and emergency shut-downs. The governing system is of the sensitive oil type in which fluid pressure is used to transmit the movement of the governor pilot valve to the operating mechanism of the governor valve, in this case the Avon throttle.

The governor is manufactured by Woodward and is driven via gearing from the end of the high speed pinion shaft. The governor is a fly-weight type and carries its own oil supply.

Woodward Governor suggests that the present system has a reliability of about 50%. In addition spare parts for this system are not carried and would have to be fabricated requiring long delivery times.

The governor, synchronizer and monitoring equipment were newly installed in 1986. The governor consists of two Woodward units: one that controls the jet acceleration on start-up and the second that controls the power turbine/generator during synchronization and MW loading.

Excitation System: The exciter is a rotating brushless type mounted on a stub to the main rotating shaft. It was designed to ANSI Specification C50-13. The AC output from the exciter armature is fed through a set of diodes that are mounted on the rotor and are used to produce a DC voltage. The voltage is fed directly to the field winding of the main generator which is also mounted on the same rotating shaft.

The excitation control system consists of a “Normal” and “Standby” automatic voltage regulator (AVR) backed up by a “Manual” control mode. The AVR controls the strength of the magnetic field in the exciter by varying the amount of current through the stationary exciter field windings.

Switchgear: Primary voltage generated by the GT is 13,300 Volts. The installed GT capacity is 13.5 MW, however based on limiting factors the unit sees normal operation of ~12 MW. Originally this power was fed through a 13.8 kV oil circuit breaker and then through a 13.8 kV fusible switch. The oil circuit breaker is no longer functional but remains installed due to the current transformer (CT’s) in this breaker. These CT’s are essential to the protection of the generator and the 13.8 kV/4.160 14 MVA transformer. Power is then fed from the transformer at 4.160 kV to breaker SSB-2 in station panelboard SB12. Power from the CT or station power also feeds a 13.8 kV fused disconnect switch through a 75 kVA 13.8 kV/575 V transformer that provides power back to the station system.

600V Standby Power: GT 600 V standby power for the MCC and auxiliaries is fed from the diesel generator bus DB34 or power centre ‘C’ via a manual transfer switch in the control room. This item feeds into an automatic transfer switch which alternately is fed from the 112 kVA transformer in the previous paragraph.

Battery Room: A battery room is located adjacent to the room that contains the MCC and switchgear. The room (approximately 1800mm-2700mm) controls a bank of batteries for the purpose of powering the DC powered emergency lubrication pumps for the GT lubrication system should the shaft driver and the AC driver lubricating pumps fail during operation of the GT. The battery system also provides a source of power to the DC lube oil pump, should the AC power supply from the station Diesel Generators or Utility power to the GT building be lost.

GTG Control System

The control system has been incrementally improved through the unit’s life. In 1970, a PLC was installed to improve overall startup and unit control. In 1986, the Gem 80/500 PLC replaced all relay logic and was the primary controlling medium for the gas turbine. In 2009, it was replaced with an Invensys (Foxboro) DCS and the PLC logic was converted to DCS logic. The DCS controls the sequencing functions of the GT as did the PLC. It is set up on the plant DCS network so that the screens can be viewed by the plant operator in the main control room. In 2009, this was replaced by a Foxboro DCS system, which has greatly improved graphics.

Control Room & MCC/Switchgear Room

Within the gas turbine building, the electrical and control systems consist of a rotating brushless exciter, an automatic voltage regulator (AVR), a start rectifier, PLC control modules, motor control centre (MCC), electronic governors, synchronizer, and protection and monitoring equipment. The brushless exciter, AVR and start rectifier were manufactured by AEI Limited of Manchester, England in the mid-1960s. The programmable logic controller (PLC), governor, synchronizer and monitoring equipment were newly installed in 1986. The exciter and AVR unit act in combination to supply a controlled DC current to the wound rotor of the main generator which in turn controls its stator terminal voltage (13.8 kV) and MVar delivery. The start rectifier converts station AC current into the high DC current necessary to rotate the jet engine to ignition. The governor consists of two Woodward units: one that controls the jet acceleration on start-up and the second that controls the power turbine/generator during synchronization and MW loading.

Switchgear

The primary voltage generated by the GT is 13,300 Volts. The installed GT capacity is 13.5 MW. However, based on limiting factors, the unit sees normal operation of less than 12 MW.

Originally, this power was fed through a 13.8 kV oil circuit breaker and then through a 13.8 kV fusible switch. The oil circuit breaker is no longer functional but remains installed due to the current transformer (CT's) in this breaker. These CT's are essential to the protection of the generator and the 13.8 kV/4.160 14 MVA transformer. Power is then fed from the transformer at 4.160 kV to breaker SSB-2 in station panelboard SB1 2. Power from the CT or station power also feeds a 13.8 kV fused disconnect switch through a 75 kVA 13.8 kV/575 V transformer that provides power back to the station system.

2.2.2 Major Maintenance History

In 1987, the original control panel and sequencing system was removed and replaced with a state of the art programmable control and sequence system (Pratt & Whitney). This system was subsequently replaced in 2009 by a Foxboro (Invensys) DCS system. The original AEI/GEC control system was removed and replaced with a Woodward Governor 2301 Control System driving an EGP3 actuator.

Other than the decision to bypass the 13.8kV oil circuit breaker, no major maintenance has been carried out.

The following is a summary of significant work completed since 2003. No major overhauls have been completed on the entire machine.

25 May 2007

- Ignitor, lead and box were replaced;

21 May 2008

- Controls review.

10 June 2008

- Fuel pump and fuel control unit (FCU) to be repaired.

15 October 2009

- Thermocouple damage, quick fixed. To be upgraded;

20 November 2009

- Commissioning;
- Fuel control solenoid valve burnt out and replaced;
- Multiple start trips due to low fuel pressure, low oil pressure, and incomplete start sequence. Several issues identified - igniter box malfunction, N2 probe incorrectly connected & poor FCU actuator tuning;
- Suggest monitoring setup for the 8 EGT thermocouples.

NL Hydro has since undertaken a number of activities with vendors that have the OEM rights to the GT sections in order to conduct detailed internal inspections of the individual sections and prepare field inspection reports complete with refurbishment estimates. None dealt specifically with the electrical and control (E&C) systems.

2.2.3 Condition Assessment & Remaining Life

TABLE 2-12 CONDITION ASSESSMENT – GT ELECTRICAL & CONTROLS

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset Level 3	Description	Detail	Cond. Summ. ID#	Condition	Status Identifier	Original Life (Base Load) Ops Hrs (Yrs)	Current Expected Minimum Remaining Life Years (Subject to Test)	End of Life (EOL) Required	Capability to Reach EOL	In Service
	7202	7310	0	Elect and Control	800A, 13.8 kV Generator Main Breaker (AEI, Type BRP17 / BVRP17)	2.3.3.2 a)	EC1	The breaker has been by-passed, but does not comprimise the protection of the Generator or T9 Transformer, as the protection still disables the excitation and trips SSB-2 on Statron Board SB12, and at the same time removes internal faults on the Generator and T9 Transformer	4/10		N/A	N/A	No	1969
	7202	7310	0	Elect and Control	13.8 kV fusible switch (J.G. Statter, Ltd. Type VLMK2)	2.3.3.2 b)	EC2	Support and spares are unavailable	4/10		N/A	N/A	No	1969
	7202	7310	0	Elect and Control	112 kVa, 13.8 kV: 600V 3ph Transformer (Cart 6 Electrical)	Part of - 2.3.3.2 c)	EC3	Good Condition	4/10		10+	2020	Yes	1969
	7202	7310	0	Elect and Control	200A, 600V, 3ph manual transfer switch (Square D)	N/A	EC4	Fair Condition, but no spares available	4/10		10+	2020	Yes	1969
	7202	7310	0	Elect and Control	200A, 600V, 3ph automatic transfer switch (Taylor Industrial Controls)	N/A	EC5	Fair Condition, but no spares available	4/10		10+	2020	Yes	1969
	7202	7310	0	Elect and Control	600V, 3ph, Dist. Panel	N/A	EC6	Fair condition, but distribution board and branch breakers are old with no spares available and have been superceeded by up-to-date equipment.	4/10		0	2020	No	1969
	7202	7310	0	Elect and Control	30 kVa, 600V: 230/115V, 1ph lighting transformer (Hammond, Type F Car E70B)	Part of - 2.3.3.2 e)	EC7	Good Condition	4/10		10+	2020	Yes	1969
	7202	7310	0	Elect and Control	MCC (AEI, Type MMC Series 1000)	2.3.3.2 d)	EC8	Contains 600V, 3ph, 230V, 3ph and 100V dc bussing. The MCC is not only obsolete, with no spares or documentation available, but also violates CEC C22.1 working space in front of the MCC is less than 1 metre and when a starter is drawn out there is a safety hazard in front of the MCC.	4/10		0	2012	No	1969
	7202	7310	0	Elect and Control	100A, 230V, 3ph lighting panel	N/A	EC9	Fair condition, but distribution board and branch breakers are old with no spares available and have been superceeded by up-to-date equipment.	4/10		1	2020	No	1969
	7202	7310	0	Elect and Control	120V dc dist. Panel	N/A	EC10	Fair condition, but distribution board and branch breakers are old with no spares available and have been superceeded by up-to-date equipment.	4/10		1	2020	No	1969
	7202	7310	0	Elect and Control	120V dc motor starters fused disconnect	N/A	EC11	Part of existing MCC	4/10		0	2020	No	1969
	7202	7310	0	Elect and Control	230V, 3ph, starter and disconnect	N/A	EC12	Part of existing MCC	4/10		0	2020	No	1969
	7202	7310	0	Elect and Control	Battery Charger (SAFT NIFE, Model SLRF 120-30)	N/A	EC13	Good Condition	4/10		10+	2020	Yes	1995
	7202	7310	0	Elect and Control	129V dc battery bank (C&D technologies)	N/A	EC14	The battery has a life expectancy of 18-25 years. Being situated in a good environment, not over-stressed and receiving regular maintenance. Product is current with replacement cells and spare parts available.	4/10		10+	2020	Yes	1995
	7202	7310	0	Elect and Control	Start rectifier (AEI)	2.3.3.2 g)	EC15	No maintenance or servicing has been carried out by the present maintenance staff.	4/10		0	2020	No	1969
	7202	7310	0	Elect and Control	Automatic voltage regulator/excitor (AEI)	2.3.3.2 g)	EC16	No maintenance or servicing has been carried out by the present maintenance staff.	4/10		0	2020	No	1969
	7202	7310	0	Elect and Control	Protection and Controls (Pratt & Whitney)	N/A	EC17	Very good condition, with spares available for the unforseen future	4/10		10+	2020	Yes	1986
	7202	7310	0	Elect and Control	DCS (Foxboro/Invensys)	N/A	EC18	Good condition - replaces the GEN80 PLC system and communicates direct into the plant DCS. DCS in operation considered "state-of-the-art" and replacement service agreement renders the system current.	4/10		10+	2020	Yes	2009
1325	5983	5983	61-00-69576	TRANSFORMERS	TRANSFORMER T9	13.8 kV	EC19	Installed in 1970, the unit is at a high level of risk due to its age. No significant issues were identified in Doble tests last done in 2001. Maintenance in 2000, 2004 and 2006 was for various gauges/relays. Silica gel was replaced in 2002 and a Dielectric test performed in 1983. The latest Planned Maintenance was in 2006. Insulating oil tests in 2009 suggests higher power loss when under operation, and also the oil has a higher solubility of polar contaminants and oxidation products.	4	(45)	5+	2020	Yes	1970

2.2.4 Risk Assessment/

TABLE 2-13 RISK ASSESSMENT – GT ELECTRICAL & CONTROLS

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset Level 3	Description	Detail	Cond. Summ. ID#	Condition	Major Issues	Remaining Life Years	TECHNO-ECO RISK ASSESS MODEL			SAFETY RISK ASSESS MODEL			Possible Failure Event	Mitigation
										(Insufficient Info - Inspection Required Within (x) Years)	Likeli--hood	Conse-quence	Risk Level	Likeli-hood	Conse-quence	Safety Risk		
	7202	7310	0	Elect and Control	800A, 13.8 kV Generator Main Breaker (AEI, Type BRP17 / BVRP17)	2.3.3.2 a)	EC1	The breaker has been by-passed, but does not comprimise the protection of the Generator or T9 Transformer, as the protection still disables the excitation and trips SSB-2 on Statron Board SB12, and at the same time removes internal faults on the Generator and T9 Transformer	Arc flash	0	1	D	Medium	1	4	Medium	Arc Flash on breaker resulting in potential for serious injury.	Breaker has been by-passed
	7202	7310	0	Elect and Control	13.8 kV fusible switch (J.G. Statter, Ltd. Type VLMK2)	2.3.3.2 b)	EC2	Support and spares are unavailable	Not able to maintain	0	4	A	Low	4	1	Medium	None likely in current configuration.	replace with new fusible switch
	7202	7310	0	Elect and Control	112 kVa, 13.8 kV: 600V 3ph Transformer (Cart 6 Electrical)	Part of - 2.3.3.2 c)	EC3	Good Condition	None	10+	1	B	Low	1	C	Low	N/A	Monitor condition.
	7202	7310	0	Elect and Control	200A, 600V, 3ph manual transfer switch (Square D)	N/A	EC4	Fair Condition, but no spares available	Not able to maintain	10+	1	A	Low	1	A	Low	N/a	Monitor condition.
	7202	7310	0	Elect and Control	200A, 600V, 3ph automatic transfer switch (Taylor Industrial Controls)	N/A	EC5	Fair Condition, but no spares available	Not able to maintain	10+	1	A	Low	1	A	Low	N/A	Monitor condition.
	7202	7310	0	Elect and Control	600V, 3ph, Dist. Panel	N/A	EC6	Fair condition, but distribution board and branch breakers are old with no spares available and have been superceeded by up-to-date equipment.	Not able to maintain	0	4	A	Low	3	A	Low	N/A	Monitor condition.
	7202	7310	0	Elect and Control	30 kVa, 600V: 230/115V, 1ph lighting transformer (Hammond, Type F Car FZ9P)	Part of - 2.3.3.2 e)	EC7	Good Condition	None	10+	1	B	Low	1	C	Low	N/A	Monitor condition.
	7202	7310	0	Elect and Control	MCC (AEI, Type MMC Series 1000)	2.3.3.2 d)	EC8	Contains 600V, 3ph, 230V, 3ph and 100V dc bussing. The MCC is not only obsolete, with no spares or documentation available, but also violates CEC C22.1 working space in front of the MCC is less than 1 metre and when a starter is drawn out there is a safety hazard in front of the MCC.	Obsolete unable to maintain. Does not conform to Candian Standards Maintance and Arc	0	4	C	High	3	D	High	Arc flash and threat of personell serios injury	Replace the MCC and Re-Cable the 600V, 230V and 110V DC power.
	7202	7310	0	Elect and Control	100A, 230V, 3ph lighting panel	N/A	EC9	Fair condition, but distribution board and branch breakers are old with no spares available and have been superceeded by up-to-date equipment.	Not able to maintain	1	4	A	Low	3	B	Medium	Lighting failure - staff safety	Replace the Start Rectifier
	7202	7310	0	Elect and Control	120V dc dist. Panel	N/A	EC10	Fair condition, but distribution board and branch breakers are old with no spares available and have been superceeded by up-to-date equipment.	Not able to maintain	1	4	C	Medium	3	C	Medium	Unit failure to start- extended period.	Replace the Start Rectifier
	7202	7310	0	Elect and Control	120V dc motor starters fused disconnect	N/A	EC11	Part of existing MCC	Obsolete unable to maintain. Does not conform to Candian Standards Maintance and Arc	0	3	C	High	2	D	High	Arc flash and threat of personell serios injury	Replace the Starter and the Fused Disconnect
	7202	7310	0	Elect and Control	230V, 3ph, starter and disconnect	N/A	EC12	Part of existing MCC	Obsolete unable to maintain. Does not conform to Candian Standards Maintance and Arc	0	4	C	High	3	D	High	Arc flash and threat of personell serios injury	Replace the Starter and the Fused Disconnect
	7202	7310	0	Elect and Control	Battery Charger (SAFT NIFE, Model SLRF 120-30)	N/A	EC13	Good Condition	None	10+	1	A	Low	1	B	Low	N/A	Monitor condition.
	7202	7310	0	Elect and Control	129V dc battery bank (C&D technologies)	N/A	EC14	The battery has a life expectancy of 18-25 years. Being situated in a good environment, not over-stressed and receiving regular maintenance. Product is current with replacement cells and spare parts available	None	10+	1	A	Low	1	B	Low	N/A	Monitor condition.
	7202	7310	0	Elect and Control	Start rectifier (AEI)	2.3.3.2 g)	EC15	No maintenance or servicing has been carried out by the present maintenance staff.	Not able to maintain	0	1	C	Medium	3	C	Medium	Unit failure to start- extended period.	Replace the Start Rectifier
	7202	7310	0	Elect and Control	Automatic voltage regulator/excitor (AEI)	2.3.3.2 g)	EC16	No maintenance or servicing has been carried out by the present maintenance staff.	Not able to maintain	0	1	C	Medium	3	C	Medium	Unit failure to start- extended period.	Replace the Automatic Voltage Regulator
	7202	7310	0	Elect and Control	Protection and Controls (Pratt & Whitney)	N/A	EC17	Very good condition, with spares available for the unforseen future	None	10+	1	A	Low	1	B	Low	N/A	Monitor condition.
	7202	7310	0	Elect and Control	DCS (Foxboro/Invensys)	N/A	EC18	Good condition - replaces the GEN80 PLC system and communicates direct into the plant DCS. DCS in operation considered "state-of-the-art" and replacement service agreement renders the system current	None	10+	1	A	Low	1	B	Low	N/A	Monitor condition.
1325	5983	5983	61-00-69576	TRANSFORMERS	TRANSFORMER T9	13.8 kV	EC19	Installed in 1970, the unit is at a high level of risk due to its age. No significant issues were identified in Doble tests last done in 2001. Maintenance in 2000, 2004 and 2006 was for various gauges/relays. Silica gel was replaced in 2002 and a Dielectric	Transformer failure	5+	2	C	Medium	2	C	Medium	Transformer core failure; oil leak etc.	Monitor condition and gas and oil tests per schedule.

2.2.5 Actions

TABLE 2-14 ACTIONS – GT ELECTRICAL & CONTROLS

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset Level 3	Description	Detail	Cond. Summ. ID#	Action	Year	Priority
	7202	7310	0	Elect and Control	800A, 13.8 kV Generator Main Breaker (AEI, Type BRP17 / BVRP17)	2.3.3.2 a)	EC1	replace 13.8kV breaker, and recommend that a new SSB-2, vacuum interrupting type , 4160V, be installed in station board Sb12, complete with Rm trip and arc flash maintenance reduction switch.	2012	1
	7202	7310	0	Elect and Control	13.8 kV fusible switch (J.G. Statter, Ltd. Type VLMK2)	2.3.3.2 b)	EC2	Replace fusable switch	2012	1
	7202	7310	0	Elect and Control	112 kVa, 13.8 kV: 600V 3ph Transformer (Cart 6 Electrical)	Part of - 2.3.3.2 c)	EC3	No recommended action		
	7202	7310	0	Elect and Control	200A, 600V, 3ph manual transfer switch (Square D)	N/A	EC4	No recommended action		
	7202	7310	0	Elect and Control	200A, 600V, 3ph automatic transfer switch (Taylor Industrial Controls)	N/A	EC5	No recommended action		
	7202	7310	0	Elect and Control	600V, 3ph, Dist. Panel	N/A	EC6	Recommend replacing with new dist. Panel and breakers	2012	2
	7202	7310	0	Elect and Control	30 kVa, 600V: 230/115V, 1ph lighting transformer (Hammond, Type F Car FZ9P)	Part of - 2.3.3.2 e)	EC7	No reocmmended action		
	7202	7310	0	Elect and Control	MCC (AEI, Type MMC Series 1000)	2.3.3.2 d)	EC8	Replace with new MCC for the 600V, 3ph system (also reference items 11 and 12)	2012	1
	7202	7310	0	Elect and Control	100A, 230V, 3ph lighting panel	N/A	EC9	Recommend replacing with new lighting panel and breakers	2012	2
	7202	7310	0	Elect and Control	120V dc dist. Panel	N/A	EC10	Recommend replacing with new dist. Panel and breakers	2012	1
	7202	7310	0	Elect and Control	120V dc motor starters fused disconnect	N/A	EC11	Recommend replacing with a new starter for the Hyd, Gov Pump and new disconnect for the 100V dc panel feed.	2012	1
	7202	7310	0	Elect and Control	230V, 3ph, motor starter and fused disconnect		EC12	Recommend replacing with a new starter for the air compressor and new disconnect for the new ACR controls	2012	1
	7202	7310	0	Elect and Control	battery charger		EC13	No recommended action		
	7202	7310	0	Elect and Control	129V dc battery bank		EC14	No recommended action		
	7202	7310	0	Elect and Control	Start rectifier		EC15	Recommend replacing with a new system	2012	1
	7202	7310	0	Elect and Control	AVR		EC16	Recommend replacing with a new system	2012	1
	7202	7310	0	Elect and Control	Prot. & Controls		EC17	No recommended action		
	7202	7310	0	Elect and Control	DCS		EC18	No recommended action		

2.2.6 Life Assessment - Life Cycle Curves (Where Equipment Is Not To Be Overhauled/replaced and Life <2020 and has Major Unit Operation Impacts)

No Life Cycle Curves are presented. The newer equipment (Controls, battery chargers, batteries) can all meet the 2020 end date. The balance (AVR, MCC, etc.) essentially should be replaced as part of any refurbishment program. Post refurbishment in line with the proposals in this report, there should be no further major significant repairs required before 2020.

2.2.7 Level 3 Inspections Required

No incremental to refurbishment Level 3 assessments are required.

2.2.8 Capital Enhancements

The suggested capital projects for the GT E&C systems are presented in Table 2-15.

TABLE 2-15 SUGGESTED TYPICAL CAPITAL ENHANCEMENTS – GAS TURBINE ELECTRICAL & CONTROLS

Asset # 2	Asset # 3	Asset # 4	Asset Level 3	Description	Detail	Cond. Summ. ID#	Capital Item	Date	Priority
7202	7310	0	Elect and Control	800A, 13.8 kV Generator Main Breaker (AEI, Type BRP17 / BVRP17)	2.3.3.2 a)	EC1	Removal of existing breaker and installation of new breaker, trays and new JB. Run power cables from new breaker to generator and to T9 tranformer, Termination of existing CT's, PT's and control cables in new JB, and extending new CT, PT and control cables from new JB to the new breaker, Extend grounding as necessary. Function test and commission.	2012	1
7202	7310	0	Elect and Control	13.8 kV fusible switch (J.G. Statter, Ltd. Type VLMK2)	2.3.3.2 b)	EC2	Removal of existing fusible switch and installation of new fusible switch, plus installation of cabling to 112 kVA transformer. Ground as necessary. Function test and commission	2012	1
7202	7310	0	Elect and Control	112 kVa, 13.8 kV: 600V 3ph Transformer (Cart 6 Electrical)	2.3.3.2 c)	EC3	Cable from 112kVA Transformer to new 13.8kV Fusible Switch	2012	1
7202	7310	0	Elect and Control	MCC (AEI, Type MMC Series 1000)	2.3.3.2 d)	EC8	Replace the MCC and Re-Cable the 600V, 230V and 110V DC power.	2012	1
7202	7310	0	Elect and Control	30 kVa, 600V: 230/115V, 1ph lighting transformer (Hammond, Type F Car FZ9P) ; New 230V, 3ph, Auxiliary Distribution Panel	2.3.3.2 e)	EC7	Install New 230V, 3ph, Auxiliary Distribution Panel. Relocate 30kVA, 3ph, 550:230V Transformer and Connect to MCC and New 230V, 3ph, Auxiliary Distribution Panel	2012	1
7202	7310	0	Elect and Control	120V dc motor starters fused disconnect	2.3.3.2 f)	EC11	New 110VDC,. NEMA 1 Breaker, new NEMA1 Splitter, new DC Starters, and Existing 100A DC Distribution Panel. New Feeders from Splitter to DC Starters and DC Distribution Panel	2012	1
7202	7310	0	Elect and Control	Start rectifier (AEI)	2.3.3.2 g)	EC15	Replace the Start Rectifier	2012	1
7202	7310	0	Elect and Control	Automatic voltage regulator/excitor (AEI)		EC16	Replace the Automatic Voltage Regulator	2012	1
7202	7310	0	Elect and Control	Miscellaneous	2.3.3.2 h)	EC20	Miscellaneous Hardware, Tray and 4/0 Grounding	2012	1
7202	7310	0	Elect and Control	Commissioning		EC21	Commissioning	2012	1
7202	7310	0	Elect and Control	Protection and Controls (Pratt & Whitney)		EC17	No Capital Required		
7202	7310	0	Elect and Control	DCS (Foxboro/Invensys)		EC18	No Capital Required		
5983	5983	61-00-69576	TRANSFORMERS	TRANSFORMER T9		EC19	No Capital Required		
7202	7310	0	Elect and Control	200A, 600V, 3ph manual transfer switch (Square D)		EC4	No Captial Requirement		
7202	7310	0	Elect and Control	200A, 600V, 3ph automatic transfer switch (Taylor Industrial Controls)		EC5	No Captial Requirement		
7202	7310	0	Elect and Control	600V, 3ph, Dist. Panel		EC6	No Capital Required		
7202	7310	0	Elect and Control	100A, 230V, 3ph lighting panel		EC9	No Captial Requirement	2012	2
7202	7310	0	Elect and Control	120V dc dist. Panel		EC10	No Captial Requirement	2012	2
7202	7310	0	Elect and Control	120V dc motor starters fused disconnect		EC11	Replace the Starter and the Fused Disconnect	2012	1
7202	7310	0	Elect and Control	230V, 3ph, starter and disconnect		EC12	Replace the Starter and the Fused Disconnect	2012	1
7202	7310	0	Elect and Control	Battery Charger (SAFT NIFE, Model SLRF 120-30)		EC13	No Capital Required		
7202	7310	0	Elect and Control	129V dc battery bank (C&D technologies)		EC14	No Capital Required		

2.2.9 Capital/Refurbishment and Overhaul Costs (Capital)

The suggested equipment and installation costs (Refurbishment of Existing Equipment) for the GT E&C systems are presented in Table 2-16.

TABLE 2-16 CAPITAL COST ESTIMATE – GAS TURBINE ELECTRICAL & CONTROLS

Asset #2	Asset #3	Asset #4	Asset Level 3	Description	Detail	Cond. Summ. ID#	Capital Item	Date	Priority	Description	Qty	Unit	Material	Labour	Total	Comments
7202	7310	0	Elect and Control	800A, 13.8 kV Generator Main Breaker (AEI, Type BRP17 / BVRP17)	2.3.3.2 a)	EC1	Removal of existing breaker and installation of new breaker, trays and new JB. Run power cables from new breaker to generator and to T9 tranformer, Termination of existing CT's, PT's and control cables in new JB, and extending new CT, PT and control cables from new JB to the new breaker, Extend grounding as necessary. Function test and commission.	2012	1	Installation of new 800A, 13.8 kV, 3ph, 60Hz Generator Main Breaker	1	ea	126860	12800	139660	
										Removal of Existing Main Breaker	1	lot	-	1600	1600	
										Installation of Cable Tray	20	m	3500	1250	4750	
										Installation of New Junction Box	1	ea	1000	480	1480	
										Removal of Existing Power Cables from Existing Breaker to Generator and T9 Transformer	1	lot	-	1600	1600	
										Installation of New Power Cables from New Breaker to Generator (2 x 500kcmil) and T9 Transformer (2x500kcmil)	180	m	50,000	10,000	60,000	
										Connection of Existing and Used CT, PT and Control Cables in New JB, and run the new CT, PT and Control Cables from new JB to new 13.8 kV Main Breaker (4 x 4c10, 1 x 4c12, 1 x 12c12).	1	lot	600	1600	2200	
7202	7310	0	Elect and Control	13.8 kV fusible switch (J.G. Statter, Ltd. Type VLMK2)	2.3.3.2 b)	EC2	Removal of existing fusible switch and installation of new fusible switch, plus installation of cabling to 112 kVA transformer. Ground as necessary. Function test and commission	2012	1	Installation of New 13.8kV Fusible Switch	1	ea	-	-		included with cost of 13.8kV
										Removal of Existing 13.8 kV Fusible Switch	1	lot	-	1600	1600	
7202	7310	0	Elect and Control	112 kVa, 13.8 kV: 600V 3ph Transformer (Cart 6 Electrical)	2.3.3.2 c)	EC3	Cable from 112kVA Transformer to new 13.8kV Fusible Switch			Install 3c2AWG, Teeck, 15kV, Cable from 112kVA Transformer to new 13.8kV Fusible Switch	10	m	750	300	1050	
7202	7310	0	Elect and Control	MCC (AEI, Type MMC Series 1000)	2.3.3.2 d)	EC8	Replace the MCC and Re-Cable the 600V, 230V and 110V DC power.	2012	1	Remove Existing MCC	1	ea	-	8000	8000	
										Install New MCC	1	ea	30000	8000	38000	
										Install Cable Tray	1	lot	1600	900	2500	
										Install New Incoming and Feeder Cables for 600V Circuits						
										3C12, Teck, 1000V, (Seven Circuits)	280	m	1260	525	1785	
										3c10, Teck, 1000V, (One Circuit)	40	m	240	120	360	
										3c6, Teck, 1000V, (Five Circuits)	200	m	1025	350	1375	
										3c2, Teck, 1000V, (One Circuit)	40	m	1040	200	1240	
7202	7310	0	Elect and Control	30 kVa, 600V: 230/115V, 1ph lighting transformer (Hammond, Type F Car FZ9P) ; New 230V, 3ph, Auxiliary Distribution Panel	2.3.3.2 e)	EC7	Install New 230V, 3ph, Auxiliary Distribution Panel. Relocate 30kVA, 3ph, 550:230V Transformer and Connect to MCC and New 230V, 3ph, Auxiliary Distribution Panel			Install New 230V, 3ph, Auxiliary Distribution Panel	1	ea	650	350	1000	
										Relocate 30kVA, 3ph, 550:230V Transformer and Connect to MCC and New 230V, 3ph, Auxiliary Distribution Panel	1	lot	-	3000	3000	
										3c12, Teck, 1000V (One Circuit)	40	m	180	75	255	
										3c10, Teck, 1000V, (Two Circuits)	40	m	120	60	180	
7202	7310	0	Elect and Control	120V dc motor starters fused disconnect	2.3.3.2 f)	EC11	New 110VDC,. NEMA 1 Breaker, new NEMA1 Splitter, new DC Starters, and Existing 100A DC Distribution Panel. New Feeders from Splitter to DC Starters and DC Distribution Panel			Install new 110VDC,. NEMA 1 Breaker, new NEMA1 Splitter, new DC Starters, and Existing 100A DC Distribution Panel	1	lot	31000	6400	37400	
										Install New Feeders from Splitter to DC Starters and DC Distribution Panel						
										3c12, Teck, 1000V (One Circuit)	40	m	180	75	255	
										3c10, Teck, 1000V, (One Circuit)	35	m	210	120	330	
										3c2, Teck 1000V (One Circuit)	16	m	410	140	550	
7202	7310	0	Elect and Control	Start rectifier (AEI)	2.3.3.2 g)	EC15	Replace the Start Rectifier	2012	1	Remove Existing AVR/Start Rectifier	1	ea	-	1600	1600	
7202	7310	0	Elect and Control	Automatic voltage regulator/excitor (AEI)		EC16	Replace the Automatic Voltage Regulator	2012	1	Install New AVR/Start Rectifier	1	ea	145,000	20,000	165,000	
7202	7310	0	Elect and Control	Miscellaneous	2.3.3.2 h)	EC20	Miscellaneous Hardware, Tray and 4/0 Grounding	2012	1	Miscellaneous Hardware, Tray and 4/0 Grounding	1	lot	7500	7500	15000	
7202	7310	0	Elect and Control	Commissioning		EC21	Commissioning	2012	1	Commissioning Costs			-	50,000	50000	

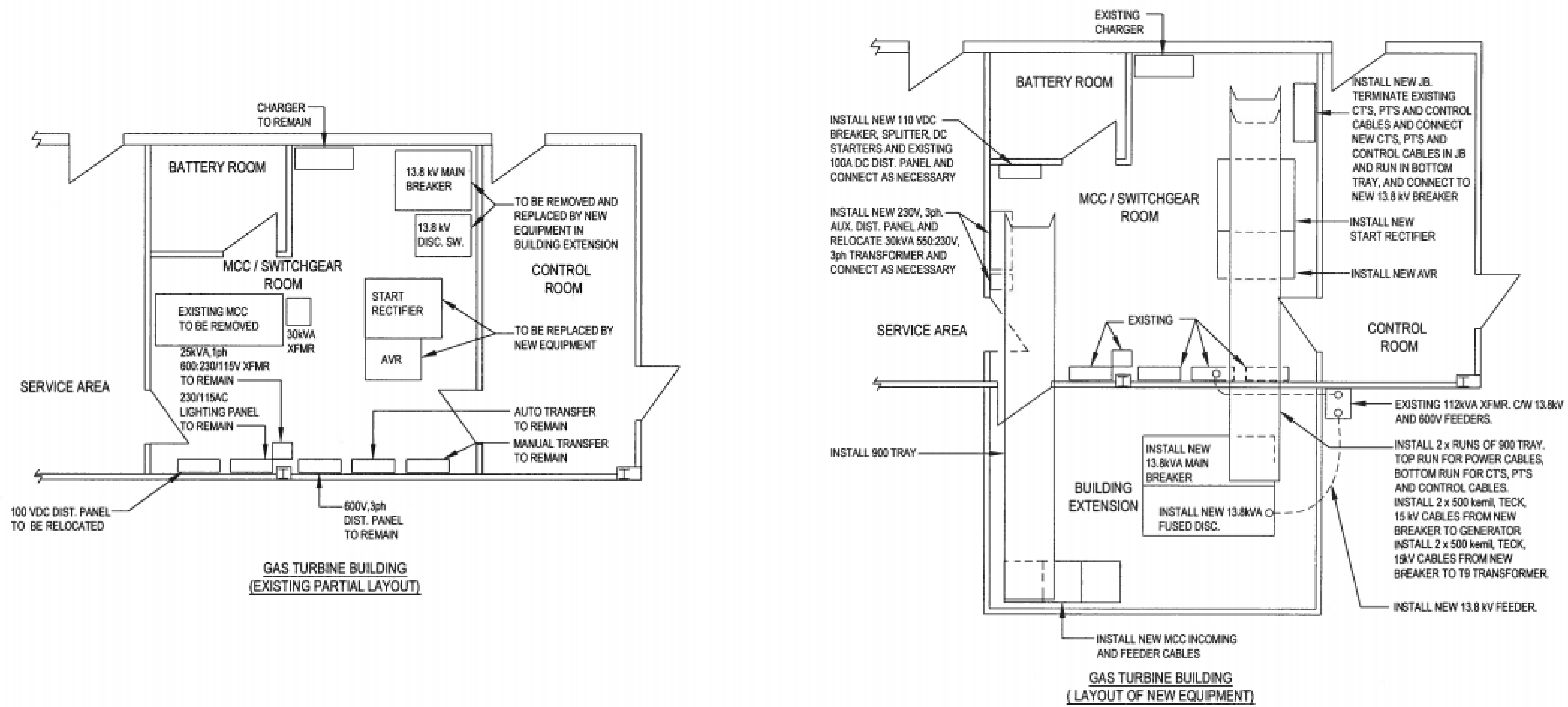


FIGURE 2-2 GAS TURBINE BUILDING – ELECTRICAL & CONTROLS – CURRENT AND PROPOSED

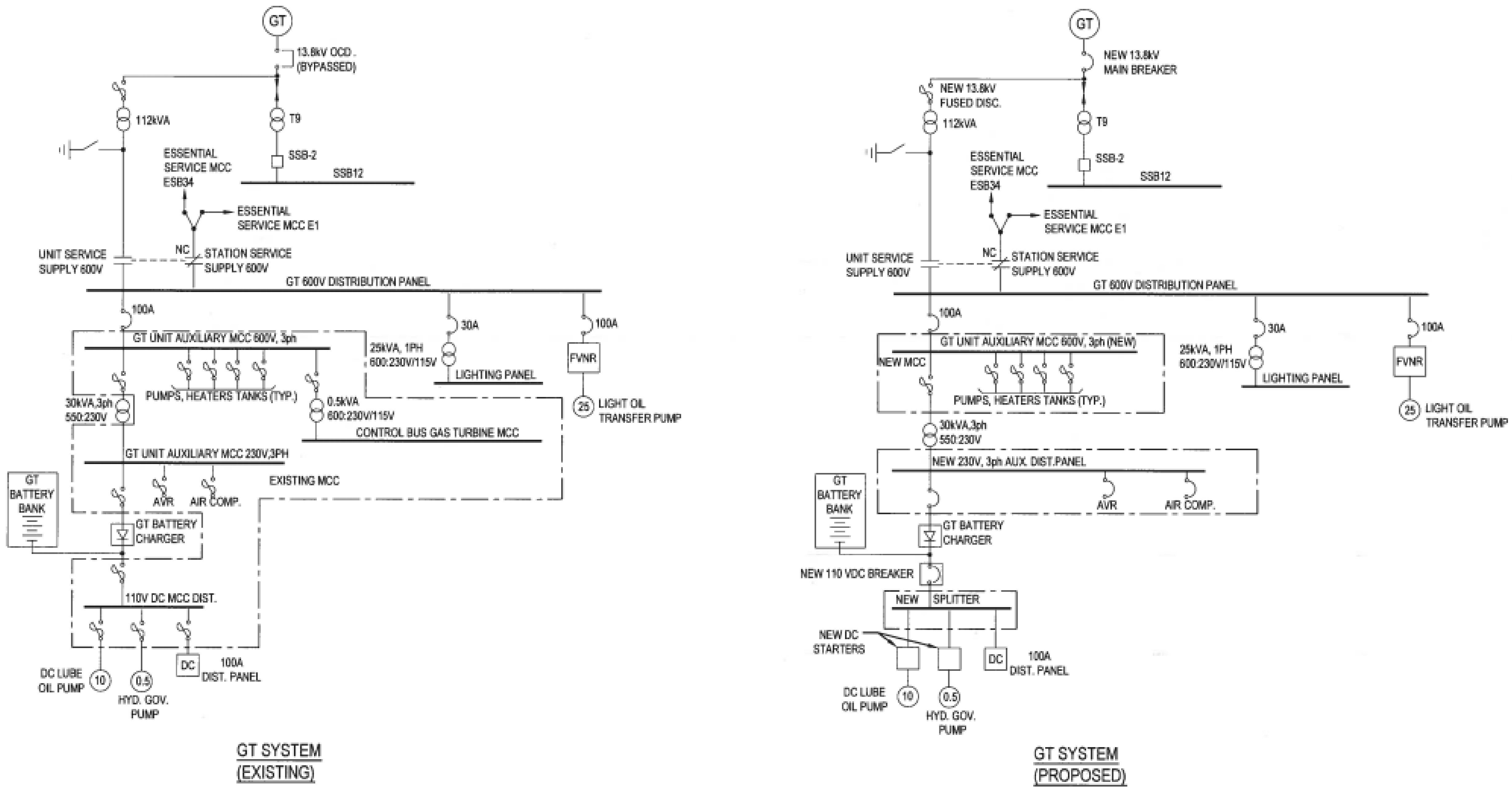


FIGURE 2-3 GAS TURBINE SINGLE LINE DIAGRAMS – CURRENT AND PROPOSED

2.3 Gas Turbine Balance of Plant (BOP) Equipment/Processes

Unit #:	GAS TURBINE
Asset Class #	BU 1273 Gas Turbine
SCI & System:	7202 Gas Turbine System
Sub-Systems:	7311 GT Aux Systems

2.3.1 Description

AC Lube Oil Cooler: The AC Lube Oil Cooler is located outside the GT building. The cooler has experienced a substantial amount of surface corrosion due to the environment. The fan is controlled by temperature logic in the lubricating oil loop. A thermostatically controlled valve is used to circulate sufficient oil flow to the cooler to maintain temperature. From discussions with site personnel the system appears to function adequately. In February 2011, the system was assessed by Siemens who noted in their report that it generally appeared in good condition but recommended some reconditioning.

Fire Protection System: The fire system is an Ansul Inergen total-flooding type system that can operate automatically via fire detection or manually via pull stations. The system is comprised of Inergen storage containers, piping, nozzles, control panel, actuators, detection and alarm devices, and pressure relief dampers. It was installed in 2000 to replace the Halon fire system in respect of the ozone depleting substance regulations.

Compressed Air & Nitrogen System: The compressed air system consists of a single 600 volt motor/compressor unit, a 310 L (82 gallon) storage tank, a Pall instrument air dryer, and a small control and monitoring panel. The system is designed to supply 700 kPa instrument air to operate the power turbine snow doors, the main generator exhaust and intake louvers, and the jet engine intake and exhaust cooling air louvers. It also has provisions for a four-bottle nitrogen back-up supply in the event of a compressor system failure. The control panel provides pressure indication for the system and a transfer valve to the nitrogen supply.

Diesel Generators: The Stage 1 and Stage 2 Diesel Generators and auxiliaries are not located within the GT building and are not part of the scope of this study. Nevertheless, they are critical to the operation of the GT units and are discussed briefly here. Two diesel units located within the main generating facility provide 600 V power for blackstart operation and start of the existing GT. They are anticipated to be required for any replacement black start generator as well.

Both diesel gensets are designed for controlled safe shutdown of the units. They have the necessary auxiliaries to be stand-alone – controls, switchgear, cooling, and lubrication.

The Stage 1 diesel was replaced in the last five years, and the Stage 2 diesel is currently planned to be replaced in 2015.

FIGURE 2-4 LIGHT OIL RECEIVING & LUBE OIL RADIATOR

EXHAUST STACK

AIR INTAKE

FIGURE 2-5 GTG EXHAUST STACK & AIR INTAKE

2.3.2 Major Maintenance History

The following is a summary of significant work completed since 2003. No major overhauls have been completed on the entire machine.

16 October 2003

- Intake plenum contained debris, chipped floor and flaking paint. Recommended clean up.

10 August 2004

- Air plenum cleaner than 2003 visit, holes still visible in walls.

27 September 2005

- Annual inspection and boroscope inspection;
- Corrosion/ Rust found in Plenum; and
- Hot gas leakage at Exhaust Transition duct to power turbine.

13 March 2006

- Leak in each end of the gearbox at the bearing seals. (Caused fire when oil leaked into insulation around PT and dripped onto top of tank). Greenray discovered turbine shaft/seal modifications, recommended machining and reconditioning.

13 April 2006

- None

25 May 2007

- Rebuild of the intake with securing bolts torque and locked; and
- Replace/ Repair exhaust snow doors.

21 May 2008

- Package filtration inspection;
- Plenum survey;
- Fuel/oil system: connection, fuel pump/ oil pump, pipelines, oil level & quality, filter and basket removal (replacement consumables); and
- On engine review: bleed valves, IGV ram (filter review), gearbox inspection (filters, speed pick up, consumable change), fuel control unit review, oil cooler, fuel filter change, burner removal (ultrasonic cleaning), fuel rail inspection, drain valve operation, thermocouple inspection (terminal cleaning), transition inspection, removal of insulation, rectify leaks, inspect LP blades.

10 June 2008

- Water pooling noted in intake plenum along with holes in structure and loose debris.

15 October 2009

- Exhaust stack needs replacement, lower components noted in good condition. Door opening components to be serviced; and
- Transition duct piston rings seals to be replaced.

20 November 2009

- Commissioning;

- Exhaust transition lagging replaced due to fuel saturation; and
- Split air manifold cracks, to be repaired.

2011

NL Hydro undertook a number of activities with vendors that have the OEM rights in order to conduct detailed internal inspections of the individual sections and prepare field inspection reports complete with refurbishment estimates.

- Rolls Wood Group has the OEM rights to the front end bearing assembly, compressor rotor, compressor casings, combustion assembly, nozzle casing, rear bearing housing, turbine assembly, exhaust unit, and accessories. They were recently contracted by NL Hydro to conduct detailed internal inspections of the above noted equipment and have prepared a field inspection report complete with refurbishment estimates.
- Braden Manufacturing is a company that specializes in the design and manufacturing of combustion turbine air filtration systems, air inlet systems, and exhaust systems. They were recently contracted by NL Hydro to perform detailed inspections of the GT air inlet plenum, air filtration system, air inlet plenum support structure, exhaust stack and exhaust stack support structure.

2.3.3 Condition Assessment & Remaining Life

TABLE 2-17 CONDITION ASSESSMENT – GAS TURBINE BOP

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset Level 3	Description	Detail	Cond. Summ. ID#	Condition	Status Identifier	Original Life (Base Load) Ops Hrs (Yrs)	Current Expected Minimum Remaining Life Years (Subject to Test)	End of Life (EOL) Required	Capability to Reach EOL	In Service
1273	7202	7311	0	GAS TURBINE AUXILIARY SYSTEMS	Fire System	Fire System	BOP1	Fire system upgraded in 2000 to Ansul Inergen total-flooding type (automatic via fire detection or manually via pull stations). All of existing Inergen system (storage containers, piping, nozzles, control panel, actuators, detection and alarm devices, and pressure relief dampers) are in good condition. Detection and suppression system did not detect 2010 GT gearbox fires - likely require some improvements.	4/10	(30)	10+	2020	Yes	2000
1273	7202	7311	0	GAS TURBINE AUXILIARY SYSTEMS	Lube Oil Cooler/Radiator	Radiator	BOP2	The cooler has experienced a substantial amount of surface corrosion due to the environment.Motor appears in good condition, but dirty. Corrosion has led to some tube leaks in 2010. Some ice freezing within containment area. Fan thermostatically controlled valve is working adequately. In February 2011 Siemens noted that the system appeared generally in good shape but recommended some reconditioning.	4	(20)	3	2020	No	1986
1273	7202	7311	0	GAS TURBINE AUXILIARY SYSTEMS	Lube Oil System	Lube Oil	BOP3	Overdue for overhaul. Gearbox lube oil seal leaks and subsequent fires have led to regulatory restriction on unit operation to emergency only.	4	(30)	0	2020	No	1986
1273	7202	7311	99003602	GAS TURBINE AUXILIARY SYSTEMS	Lube Oil Pumps	AC & DC pumps	BOP4	Siemens indicated AC and DC lube oil pumps in good condition, but no internal inspection or vibration test practical. Plant experienced that lube oil delivery engine driven pump was not maintaining sufficient main pressure, requiring the AC pump to operate continuously.	4/10	(30)	2	2020	No	1986
1297	7199	7205	0	COMPRESSED AIR SYSTEMS	Compressed Air Systems	N/A	BOP5	The single 600 volt motor/compressor unit, 310 L (82 gallon) storage tank, Pall instrument air dryer and small control and monitoring panel are fairly new and in good condition.The pressure vessels are inspected annually in accordance with government regulations. No indication of any significant degradation.	4	30	10+	2020	Yes	2000
1297	7199	7205	7231	COMPRESSED AIR SYSTEMS	Nitrogen(Compressed Air Back-up) System	N/A	BOP6	The four-bottle nitrogen back-up supply (used in the event of a compressor system failure) and its control panel driven transfer valve are in good operable condition. No issues identified.	4	30	10+	2020	Yes	2000

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

The current inspection and maintenance program for the diesels is reasonable and should suffice to allow the units to reach their normal end of life. If the existing level II generator replacement is delayed this will impact the reliability of the overall system to operate in black start.

The maintenance required on the AC lube oil cooler recommended by Siemens in the February 2011 report should be completed to ensure reliability.

Review of the information available on the fires on the existing GT does not mention any activation of the Inergen system. It was noted from inspection of the system in the turbine room that there appears to be only one discharge nozzle in which is located above the compressor section of the GT. This was later confirmed during a review of existing drawings. The fires occurred on the opposite side of the room behind the exhaust stack which would likely have reduced the effectiveness of the system in the event of a discharge. The three detectors in the room also appear to be heat detectors and not smoke which is possibly why the system did not react to the fires which have been described as a small amount of flame and smoke. These fires were extinguished by several portable units.

In general, the lube oil system is in poor shape and in need of refurbishment as part of the overhaul. The fire system, while relatively new and capable of lasting beyond 2020, requires modification for functionality reasons. The air compressor and nitrogen systems are relatively new and will last beyond 2020 with reasonable maintenance.

2.3.4 Risk Assessment

TABLE 2-18 RISK ASSESSMENT – GAS TURBINE BOP

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset Level 3	Description	Detail	Cond. Summ. ID#	Condition	Major Issues	Remaining Life Years	TECHNO-ECO RISK ASSESS MODEL			SAFETY RISK ASSESS MODEL			Possible Failure Event	Mitigation
										(Insufficient Info - Inspection Required Within (x) Years)	Likeli-- hood	Conse- quence	Risk Level	Likeli- hood	Conse- quence	Safety Risk		
1273	7202	7311	0	GAS TURBINE AUXILIARY SYSTEMS	Fire System	Fire System	BOP1	Fire system upgraded in 2000 to Ansul Inergen total-flooding type (automatic via fire detection or manually via pull stations). All of existing Inergen system (storage containers, piping, nozzles, control panel, actuators, detection and alarm devices, and pressure relief dampers) are in good condition. Detection and suppression system did not detect 2010 GT gearbox fires - likely require some improvements.	Fire detection failure and suppression failure exists.	10/0	4	C	High	3	D	High	Failure to detect and suppress fire	Modify detection and suppression system. In GTG area cameras for external monitoring.
1273	7202	7311	0	GAS TURBINE AUXILIARY SYSTEMS	Lube Oil Cooler/Radiator	Radiator	BOP2	The cooler has experienced a substantial amount of surface corrosion due to the environment.Motor appears in good condition, but dirty. Corrosion has led to some tube leaks in 2010. Some ice freezing within containment area. Fan thermostatically controlled valve is working adequately. In February 2011 Siemens noted that the system appeared generally in good shape but recommended some reconditioning.	Lube Oil cooler failure and leak - containment limits risk. Unit 8navailability.	3	3	B	Medium	3	A	Low	Tube failures. Unavailable due to ice freeze up.	Repair/replace with winter icing protection.
1273	7202	7311	0	GAS TURBINE AUXILIARY SYSTEMS	Lube Oil System	Lube Oil	BOP3	Overdue for overhaul. Gearbox lube oil seal leaks and subsequent fires have led to regulatory restriction on unit operation to emergency only.	Gearbox seal oil leaks exist and fires have occurred.	0	4	C	High	4	D	High	Fire	New seals; gearbox lube oil air vents; monitor. Improve fire detection and suppression.
1273	7202	7311	0	GAS TURBINE AUXILIARY SYSTEMS	Lube Oil Pumps	AC & DC pumps	BOP4	Siemens indicated AC and DC lube oil pumps in good condition, but no internal inspection or vibration test practical. Plant experienced that lube oil delivery engine driven pump was not maintaining sufficient main pressure, requiring the AC pump to operate continuously.	Lube oil system AC pump overuse	2	4	B	Medium	4	A	Low	Pump failure (DC back-up and shutdown)	Repair
1297	7199	7205	0	COMPRESSED AIR SYSTEMS	Compressed Air Systems	N/A	BOP5	The single 600 volt motor/compressor unit, 310 L (82 gallon) storage tank, Pall instrument air dryer and small control and monitoring panel are fairly new and in good condition.The pressure vessels are inspected annually in accordance with government regulations. No indication of any significant degradation.	None	10+	1	D	Low	1	A	Low	High pressure air storage failure. Winter stack doors don't open (N2 back-up)	Monitor
1297	7199	7205	7231	COMPRESSED AIR SYSTEMS	Nitrogen(Compressed Air Back-up) System	N/A	BOP6	The four-bottle nitrogen back-up supply (used in the event of a compressor system failure) and its control panel driven transfer valve are in good operable condition. No issues identified.	None	10+	1	D	Low	1	A	Low	High pressure N2 storage failure. Winter stack doors don't open	Monitor

2.3.5 Actions

TABLE 2-19 ACTIONS – GAS TURBINE BOP

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset Level 3	Description	Detail	Action Summ. ID#	Action	Year	Priority
1273	7202	7311	0	GAS TURBINE AUXILIARY SYSTEMS	Fire System	Fire System	BOP1	Modify fire detection and suppression system. Install GTG room cameras	2012	1
1273	7202	7311	0	GAS TURBINE AUXILIARY SYSTEMS	Lube Oil Cooler/Radiator	Radiator	BOP2	Replace/Repair/refurbish and eliminate icing issues. If re-conditioned, stem clean motor and perform no load and vibration tests.	2012	2
1273	7202	7311	0	GAS TURBINE AUXILIARY SYSTEMS	Lube Oil System	Lube Oil	BOP3	New seals; gearbox lube oil air vents; monitor. Improve fire detection and suppression.	2012	1
1273	7202	7311	99003602	GAS TURBINE AUXILIARY SYSTEMS	LUBE OIL PUMPS		BOP4	Overhaul AC and DC motors (steam clean). Perform VPI test for insulation. Perform no load and vibration tests. Install anti-condensation heaters.	2012	1
1297	7199	7205	0	COMPRESSED AIR SYSTEMS	COMPRESSED AIR SYSTEMS	N/A	BOP5	None - monitor		
1297	7199	7205	7231	COMPRESSED AIR SYSTEMS	NITROGEN (COMPRESSOR BACK-UP) SYSTEM	N/A	BOP6	None - monitor		

2.3.6 Life Assessment - Life Cycle Curves (Where Equipment Is Not To Be Overhauled/replaced and Life <2020 and Has Major Unit Operation Impacts)

No Life Cycle Curves are presented. The newer equipment and systems (compressed air, nitrogen) can all meet the 2020 end date with normal maintenance. The lube oil system requires refurbishment and with normal maintenance, should be able to meet the 2020 end date. The AC lube oil cooler fan is recommended to have the repairs recommended by Siemens to maximize the remaining life of the system or be replaced. It will then, with regular intervals of repair and maintenance, last to 2020.

The Stage 1 diesel, not a part of this assessment, but is relatively new and therefore expected to be operational until at least 2020. The Stage 2 diesel is original equipment, installed in 1979. It is at the end of its normal useful life.

2.3.7 Level 3 Inspections Required

No incremental to refurbishment Level 3 assessments are required.

2.3.8 Capital Enhancements

The suggested capital projects for the GT E&C systems are presented in Table 2-20.

TABLE 2-20 SUGGESTED TYPICAL CAPITAL ENHANCEMENTS – GAS TURBINE BOP

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset Level 3	Description	Detail	Cond. Summ. ID#	Capital Item	Date	Priority
1273	7202	7311	0	GAS TURBINE AUXILIARY SYSTEMS	Fire System	Fire System	BOP1	Modification of detection and suppression system for better protection and coverage. New monioring camera system.	2012	1
1273	7202	7311	0	GAS TURBINE AUXILIARY SYSTEMS	Lube Oil Cooler/Radiator	Radiator	BOP2	New lube oil cooler	2012	1
1273	7202	7311	0	GAS TURBINE AUXILIARY SYSTEMS	Lube Oil System	Lube Oil	BOP3	New gear box seals, lube oil venting	2012	1
1273	7202	7311	0	GAS TURBINE AUXILIARY SYSTEMS	Lube Oil Pumps	AC & DC pumps	BOP4	No Captial Requirement		
1297	7199	7205	0	COMPRESSED AIR SYSTEMS	Compressed Air Systems	N/A	BOP5	No Captial Requirement		
1297	7199	7205	7231	COMPRESSED AIR SYSTEMS	Nitrogen(Compressed Air Back-up) System	N/A	BOP6	No Captial Requirement		

2.3.8.1 Capital Refurbishment Requirements and Costs

The Stage 2 diesel and its auxiliary systems should be replaced to achieve 2020.

The AC lube oil cooler fan requires refurbishment as recommended by Siemens.

Since there is a likelihood of a fire in the area near the exhaust stack and above the gearbox, it is recommended that additional nozzles be added to the turbine room above the gearbox near the stack, and under the turbine in the vicinity of the origin of the fires to ensure unobstructed effective dispersion of the Inergen gas. It is also recommended that the addition of infrared flame detectors be considered as thermal lag on fixed temperature detectors can delay the activation of the system as can a slowly developing fire on rate of rise detectors. The flame detector effectiveness will depend on the ambient heat radiation from the gas turbine which can decrease its effectiveness.

The suggested typical capital enhancements for the gas turbine BOP include:

TABLE 2-21 CAPITAL COST – GAS TURBINE BOP

Capital cost estimate $ 1,000 Can 2011

BOP Systems		Material	Labour	Total	Range
	Fuel enclosure (See Civil/Structural)				
	Fuel piping	$60	$15	$75	$60-$90
	Stack removal	$0	$30	$30	$25-$35
	Inergen system	$7	$3	$10	$7-$15
	Lube oil cooler	$130	$20	$150	$75-$175
	Sub-Total	**$197**	**$68**	**$265**	**$150-$320**
10%	**Contingency**	**$20**	**$7**	**$27**	
	TOTAL BOP	**$217**	**$75**	**$292**	**$180-$350**

2.4 Gas Turbine/Fuel Oil Equipment/Processes

Unit #:	Common
Asset Class #	BU 1297 - Assets Common
SCI & System:	7199 HRD Common Systems
Sub-System	7209 Light Oil System
Components:	To Be Added

2.4.1 Description - Gas Turbine Generator Light Fuel Oil System

Light fuel oil (No.2 diesel) is delivered by truck to the unloading skid adjacent to the existing GT generator building. The single 600 volt off-loading pump with local start / stop control is located outdoors at the northwest corner of the gas turbine building and has above-ground piping connecting it to the bulk storage tanks. Power for the motor is supplied from the gas turbine MCC control centre. The two 100,000 litre above-ground fuel tanks were fabricated in 1998 to ULC-S601-93 standards with double wall construction and have a total storage capacity of 200,000 litres. The offloading system is comprised of a single 600 volt pump arrangement with local start / stop control. Power for the motor is supplied from the GT MCC control centre.

The piping installation is typical with a 3 inch Y strainer, isolation valves and piping to the storage tanks. Two 100%, 600 volt, centrifugal forwarding pumps provides low pressure No.2 diesel fuel for the jet engine. The fuel passes through a duplex suction strainer and a 5 micron discharge filter before reaching the jet engine. The fuel line also incorporates a fuel flow/totalizing meter and a fire system trip valve prior to entering the building.

Light oil (No.2 fuel oil) from the light oil fuel oil storage tanks is gravity fed. The light oil pressure at the main units is maintained through constant recirculation back to the light oil storage tanks through a pressure control valve and piping arrangement.

The existing fuel supply system to the GT, fire alarm fuel shut off valve, and fuel offloading system are located adjacent to the GT building and is exposed to a harsh marine environment and as a result, has heavy surface corrosion.

The fuel lines in the dike area are in better condition likely as a result of being at least partially protected from the elements.

Some fuel forwarding pumps are located in a small enclosure to protect them from the elements. The concrete containment system in which the pumps sit was filled with approximately 4 inches of oily water at the time of the inspection.

FIGURE 2-6 LIGHT OIL RECEIVING SYSTEM AND STORAGE TANKS

2.4.2 Major Maintenance History

Light Oil Storage Tanks & Receiving System: The light oil storage tanks are approximately 13 years old. Aside from the issue that the interstitial pressure was outside its normal design levels, we are not aware of any major maintenance items on these tanks. Inspection information was not considered given the relatively short duration since their in-service date. They are subject to API regulatory inspection.

Pipelines: The lines under the roadway have been replaced as part of road repair work carried out in 2007.

2.4.3 Condition Assessment & Remaining Life

The condition assessment of the fuel systems (light oil) is illustrated below in Table 2-22.

TABLE 2-22 CONDITION ASSESSMENT – GAS TURBINE FUEL OIL SYSTEM

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset Level 3	Description	Detail	Cond. Summ. ID#	Condition	Status Identifier	Original Life (Base Load) Ops Hrs (Yrs)	Current Expected Minimum Remaining Life Years (Subject to Test)	End of Life (EOL) Required	Capability to Reach EOL	In Service
1273	7202	7311	0	GAS TURBINE AUXILIARY SYSTEMS	LIGHT FUEL OIL SYSTEM									
1297	7199	7209	0	LIGHT OIL SYSTEM	GENERAL	General	LFO1	Exposed receiving and delivery system componets corroded. Build-ups of snow and ice freeze up in containment areas common.	4	(40)	(2)	2020	No	1986
1297	7199	7209	0	LIGHT OIL SYSTEM	PIPING	N/A	LFO2	Significant external corrosion and pitting.due to the marine environment, including the lines to the light oil storage tanks. Recent ultrasonic testing (Oct 2010) indicates that the piping is within acceptable wall thickness tolerances despite the external corrosion at the moment. The fuel pumps located in the small enclosures are not readily accessible and would be less so during the winter.significant weather that may prevent emergency repairs on the exposed fuel equipment in the event of a black start requirement.	4	(40)	(2)	2020	No	1986
1297	7199	7209	0	LIGHT OIL SYSTEM	GT TRANSFER PUMPS AND FILTERS	N/A	LFO3	The fuel pumps and filters are located in small enclosures are not readily accessible. Siemens indicated that motors appear in fair condition with some surface corrosion. Conduit appeared in good condition. A full assessment was not possible due to accessibility. The enclosures still fill somewhat with water and snow. The concrete containment system in which the pumps sit was filled approximately 4" with oily water at the time of the visit. THis may freeze in winter and snow makes them less accessible during the winter which may prevent emergency repairs on the exposed fuel equipment in the event of a black start requirement.	4	(40)	(2)	2020	No	1986
1297	7199	7209	0	LIGHT OIL SYSTEM	FUEL RECEIVING/FORWARDING PUMPS	N/A	LFO4	The fuel receiving/transfer pumps, fire alarm fuel shut off valve, and fuel offloading system are located adjacent to the Gas Turbine Building and exposed to a harsh marine environment and have heavy surface corrosion as a result. Snow and ice in winter makes them less accessible and may prevent emergency repairs on the exposed fuel equipment in the event of a black start requirement.	4	(40)	(2)	2020	No	1986
1297	7199	7209	99034713	LIGHT OIL SYSTEM	OIL STORAGE TANK	General	LFO5	Relatively new, about 13 years. No inspections that station are aware of.	3a	(40)	10+	2020	Yes	1998
1297	7199	7209	99034713	LIGHT OIL SYSTEM	OIL STORAGE TANK	N/A	LFO6	Interstitial vacuum pressure on both tanks are -35 and -38 mm Hg. Very faded warning stickers on the tanks indicated if the vacuum pressure was less than – 42 mm Hg the manufacturer should be contacted. While the gauges still indicate a high vacuum in each tank, there is a concern tahta Holyrood management acknowledged this as an ongoing issue with the tanks that they were aware of.	3a	(40)	10+	2020	Yes	1998
1297	7199	7209	99034713	LIGHT OIL SYSTEM	OIL STORAGE TANK	N/A	LFO7	Fuel oil tank penetrations on the top of the tank are showing heavy corrosion. No other data available.	3a	(40)	10+	2020	Yes	1998

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

A review of the 2006 SGE Acres report “Evaluation of Fuel Oil Storage Tanks, Associated Pipelines and dike Drainage System Holyrood Thermal Generating Station” was used to determine the existing condition of the tanks in conjunction with a walkthrough of the tank farm. During examination of the two light oil tanks, it was noted that the interstitial vacuum pressure on both tanks are -35 and -38 mm HG . Very faded warning stickers on the tanks indicated if the vacuum pressure was less than 42 mm hg the manufacture should be contacted. While the gauges still indicate a high vacuum in each tank, the concern was brought forward to Holyrood management and was acknowledged as an ongoing issue with the tanks that they were aware of.

It was also noted that the fuel oil tank penetrations on the top of the tank are showing heavy corrosion. Since these tanks are critical to the operation of diesel gensets, the black start gas turbine, and main unit ignition it is recommended that this corrosion be addressed through regular maintenance.

The light oil receiving, pumping and piping system located at the gas turbine building is operational, but have experienced significant external corrosion due to the marine environment, including the lines to the light oil storage tanks and to the powerhouse ignition oil system. Some data was made available on ultrasonic testing of the lines from October 2010, it appears from preliminary review of the results that the piping is within acceptable wall thickness tolerances despite the external corrosion at the moment. The fuel pumps located in the small enclosures are not readily accessible and would be less so during the winter.

The piping exterior is in poor condition due to its prolonged exposure to the marine environment. Extreme weather may prevent emergency repairs on the exposed fuel equipment during a black start event. Given their exposure to the harsh marine environment, the existing fuel supply system to the gas turbine, the fire alarm fuel shut off valve, and the fuel offloading system located adjacent to the G Building is not expected to continue to 2020. While the majority of the components are fairly standard and off the shelf, a failure of the Gas Turbine fuel system during black start would be costly both financially and in terms of time.

2.4.4 Risk Assessment

TABLE 2-23 RISK ASSESSMENT – GAS TURBINE FUEL OIL SYSTEM

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset Level 3	Description	Detail	Cond. Summ. ID#	Condition	Major Issues	Remaining Life Years (Insufficient Info - Inspection Required Within (x) Years)	TECHNO-ECO RISK ASSESS MODEL Likeli–hood	Conse-quence	Risk Level	SAFETY RISK ASSESS MODEL Likeli-hood	Conse-quence	Safety Risk	Possible Failure Event	Mitigation
1273	7202	7311	0	GAS TURBINE AUXILIARY SYSTEMS	LIGHT FUEL OIL SYSTEM													
1297	7199	7209	0	LIGHT OIL SYSTEM	GENERAL	General	LFO1	Exposed receiving and delivery system componets corroded. Build-ups of snow and ice freeze up in containment areas common.	Oil Leak; failure to operate and access easily.	(2)	3	A	Low	4	A	Medium	Modest oil spill within containment; inability to start unit until ice cleared	Install new fuel receing/handling shed
1297	7199	7209	0	LIGHT OIL SYSTEM	PIPING	N/A	LFO2	Significant external corrosion and pitting.due to the marine environment, including the lines to the light oil storage tanks. Recent ultrasonic testing (Oct 2010) indicates that the piping is within acceptable wall thickness tolerances despite the external corrosion at the moment. The fuel pumps located in the small enclosures are not readily accessible and would be less so during the winter.significant weather that may prevent emergency repairs on the exposed fuel equipment in the event of a black start requirement.	Oil Leak; failure to operate and access easily.	(2)	3	A	Low	4	A	Medium	Modest oil spill within containment; inability to start unit until ice cleared	Install new fuel receing/handling shed
1297	7199	7209	0	LIGHT OIL SYSTEM	GT TRANSFER PUMPS AND FILTERS	N/A	LFO3	The fuel pumps and filters are located in small enclosures are not readily accessible. The enclosures still fill somewhat with water and snow. The concrete containment system in which the pumps sit was filled approximately 4" with oily water at the time of the visit. THis may freeze in winter and snow makes them less accessible during the winter which may prevent emergency repairs on the exposed fuel equipment in the event of a black start requirement.	Oil Leak; failure to operate and access easily.	(2)	3	A	Low	4	A	Medium	Modest oil spill within containment; inability to start unit until ice cleared	Install new fuel receing/handling shed
1297	7199	7209	0	LIGHT OIL SYSTEM	FUEL RECEIVING/FORWARDING PUMPS	N/A	LFO4	The fuel receiving/transfer pumps, fire alarm fuel shut off valve, and fuel offloading system are located adjacent to the Gas Turbine Building and exposed to a harsh marine environment and have heavy surface corrosion as a result. Snow and ice in winter makes them less accessible and may prevent emergency repairs on the exposed fuel equipment in the event of a black start requirement.	Oil Leak; failure to operate and access easily.	(2)	3	A	Low	4	A	Medium	Modest oil spill within containment; inability to start unit until ice cleared	Install new fuel receing/handling shed
1297	7199	7209	99034713	LIGHT OIL SYSTEM	OIL STORAGE TANK	General	LFO5	Relatively new, about 13 years. No inspections that station are aware of.	Regulatory out of complince.	10+	2	A	Low	2	B	Medium	Ensure regulatoy inspection compliance undertaken.	Tank inspection.
1297	7199	7209	99034713	LIGHT OIL SYSTEM	OIL STORAGE TANK	N/A	LFO6	Interstitial vacuum pressure on both tanks are -35 and -38 mm Hg. Very faded warning stickers on the tanks indicated if the vacuum pressure was less than – 42 mm Hg the manufacturer should be contacted. While the gauges still indicate a high vacuum in each tank, there is a concern tahta Holyrood management acknowledged this as an ongoing issue with the tanks that they were aware of.	Operating outside vendor recommended limits. Leak..	10+	3	A	Low	2	B	Medium	Modest oil spill within containment; inability to start unit until ice cleared	Investigate rezson and repair. Replace warning stickers.

2.4.5 Actions

TABLE 2-24 ACTIONS – GAS TURBINE FUEL OIL SYSTEM

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset Level 3	Description	Detail	Action Summ. ID#	Action	Year	Priority
1273	7202	7311	0	GAS TURBINE AUXILIARY SYSTEMS	LIGHT FUEL OIL SYSTEM					
1297	7199	7209	0	LIGHT OIL SYSTEM	GENERAL	General	LFO1			
1297	7199	7209	0	LIGHT OIL SYSTEM	PIPING	N/A	LFO2	Replace fuel piping downstream of filters with stainless. Refurbsih remaining piping, vales etc. Enclose building related equipment in fuel shed.	2012	2
1297	7199	7209	0	LIGHT OIL SYSTEM	GT TRANSFER PUMPS AND FILTERS	N/A	LFO3	Replace fuel receiving and transfer piping. Enclose in fuel shed.	2012	1
1297	7199	7209	0	LIGHT OIL SYSTEM	FUEL RECEIVING/FORWARDING PUMPS	N/A	LFO4	Replace fuel receiving and transfer piping. Enclose in fuel shed.	2012	1
1297	7199	7209	99034713	LIGHT OIL SYSTEM	OIL STORAGE TANK	General	LFO5			
1297	7199	7209	99034713	LIGHT OIL SYSTEM	OIL STORAGE TANK	N/A	LFO6	Inspect per regulatory and maintain	2012	1
1297	7199	7209	99034713	LIGHT OIL SYSTEM	OIL STORAGE TANK	N/A	LFO7	Investigate interstial vacuum difference and repair. Replace warning stickers.	2012	2

2.4.6 Life Assessment - Life Cycle Curves (Where Equipment Is Not To Be Overhauled/Replaced and Life <2020 and Has Major Unit Operation Impacts)

No Life Cycle Curves are presented. The system should be capable of meeting the 2020 end date with reasonable maintenance. Modifications including stainless steel piping from filters to the GT, and the installation of a fuel shed and replacement of system to address winter weather impacts. The issue is primarily problems resulting from extreme weather impacts and less with the equipment itself. The oil storage tanks should with maintenance and regulatory inspection make the 2020 end date.

2.4.7 Level 3 Inspections Required

Given the condition historical data reviewed and recommended changes, no Level 3 analyses are necessary.

2.4.8 Capital Enhancements

The suggested capital projects for the GT E&C systems are presented in Table 2-25.

TABLE 2-25 SUGGESTED TYPICAL CAPITAL ENHANCEMENTS – GAS TURBINE FUEL OIL SYSTEM

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset Level 3	Description	Detail	Cond. Summ. ID#	Capital Item	Date	Priority
1273	7202	7311	0	GAS TURBINE AUXILIARY SYSTEMS	LIGHT FUEL OIL SYSTEM					
1297	7199	7209	0	LIGHT OIL SYSTEM	GENERAL	General	LFO1	New fuel shed.	2012	1
1297	7199	7209	0	LIGHT OIL SYSTEM	PIPING	N/A	LFO2	New stainless steel piping from filters to GTG	2012	1
1297	7199	7209	0	LIGHT OIL SYSTEM	GT TRANSFER PUMPS AND FILTERS	N/A	LFO3	New system	2012	1
1297	7199	7209	0	LIGHT OIL SYSTEM	FUEL RECEIVING/FORWARDING PUMPS	N/A	LFO4	New system	2012	1
1297	7199	7209	99034713	LIGHT OIL SYSTEM	OIL STORAGE TANK	General	LFO5	No Captial Requirement		
1297	7199	7209	99034713	LIGHT OIL SYSTEM	OIL STORAGE TANK	N/A	LFO6	No Captial Requirement		
1297	7199	7209	99034713	LIGHT OIL SYSTEM	OIL STORAGE TANK	N/A	LFO7	No Captial Requirement		

2.4.9 Capital/Refurbishment and Overhaul Costs (Capital)

It is recommended that the fuel system, fire alarm fuel shut off valve and fuel offloading system be refurbished/replaced and be enclosed in a full sized shelter. This will help protect the exposed equipment and allow for safe operation and repairs unhindered by weather and enclosures too small to work in.

The suggested equipment and installation costs (refurbishment of existing equipment) for the system are presented in Table 2-26.

TABLE 2-26 CAPITAL COST ESTIMATE – GAS TURBINE FUEL OIL SYSTEM

Item	Cost
Fuel enclosure	$40,000
Fuel piping	$75,000
Stack removal	$ 30,000
Inergen system	$10,000
Lube oil cooler	$150,000

2.5 Building and Structural/Civil Equipment

Unit #:	COMMON
Asset Class #	BU 1297 – Assets Common
SCI & System:	7255 HRD Buildings & Site
Sub-Systems:	272255 HRD Buildings
Components:	7307 HRD Gas Turbine Building
Sub-Components:	7307 HRD Gas Turbine Building

2.5.1 Description

The GT building at the plant houses the GT that is used in the event of a black start. The existing gas turbine building was constructed in 1986. The building is of pre-engineered, galvanized metal-panel construction, 40 ft in width and 50 ft in length with R20 exterior wall insulation. The foundation is of conventional reinforced concrete pier/wall and floor slab construction and incorporates the original turbine and module slabs. A full height concrete block partition wall was installed to completely separate the turbine/generator sections from the remaining building area. It houses a one tonne hoist/track provision to move equipment to the service area. The electrical area is divided into a battery room, a control room and an MCC/switchgear section. It has an oil drain provision for both the service and turbine rooms complete with a reinforced concrete trap. A rolling service door between the turbine and work area is provided for fire containment but easily removed for heavy equipment.

2.5.1.1 Gas Turbine Building Asbestos

Pinchin Leblanc undertook an "Asbestos Materials Re-Assessment" study of Holyrood for NL Hydro in 2010 (Pinchin Leblanc Project 02-02-004-01, November 19, 2010).

The study was not exhaustive and rather a review of areas identified previously, some of which had been addressed. It did not appear to address the GT building specifically, but did indicate that the metal sheet siding of some of the out buildings on the site were made of a material called Galbestos which had a backing of non-friable tarpaper containing chrysotile asbestos. The study indicated that this siding material should be repaired or removed following Type 1 (low risk) asbestos abatement procedures.

Given that the GT building was installed at the Holyrood site in 1986, it is unlikely that the siding material was Galbestos. Nevertheless, before any modification work is undertaken on the siding or other building components, the presence or absence of asbestos should be verified.

No cost or time has been allowed for asbestos evaluation or removal in this assessment, as the likelihood of its presence is low and the risk associated with its removal is identified by the report as being low.

2.5.2 Major Maintenance History

No inspection records specific to the turbine building were identified. A visual walkthrough of the gas turbine building was performed to gauge the existing condition of the building.

Structural: The structural systems that comprise the building are in excellent condition with very little corrosion found and no major structural deficiencies noted. There was significant surface corrosion found on the structural members located below the exhaust stack that sits on the roof of the building over the turbine.

Roofs & Siding: The siding and roof of the gas turbine building, specifically in the area around the stack, at the roofliner, and at the base of the building, show evidence of significant corrosion.

Exhaust Stack: The exhaust stack is extensively corroded with leaks into the building and into the turbine, and should be replaced.

Picture shows corroded exhaust stack

Picture shows corroded exhaust stack

Picture shows corroded exhaust stack

Picture shows corroded exhaust stack

FIGURE 2-7 CORRODED EXHAUST STACK (GAS TURBINE PLANT

2.5.3 Condition Assessment & Remaining Life

The condition assessment of the buildings and building M and E system is illustrated below in Table 2-27.

TABLE 2-27 CONDITION ASSESSMENT – GAS TURBINE BUILDINGS AND BUILDING M AND E SYSTEM

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset Level 3	Description	Detail	Cond. Summ. ID#	Condition	Status Identifier	Original Life (Base Load) Ops Hrs (Yrs)	Current Expected Minimum Remaining Life Years (Subject to Test)	End of Life (EOL) Required	Capability to Reach EOL	In Service
1297	7255	272255	7307	BUILDINGS	GAS TURBINE BUILDING	N/A	BLDG1	Generally in good condition with modest corrosion and no significant structural deficiencies noted, except where related to gas turbine intake and exhaust. Some surface corrosion on structural members located below the exhaust stack. Sidings and roofs of the Gas Turbine Building have some corrosion requiring repair.	4	(40)	10+	2020	Yes	1986
1273	7202	7311	0	GAS TURBINE BUILDING	Structure - General	Structure	BLDG2	The structural systems that comprise the building are in excellent condition with very little corrosion found and no major structural deficiencies noted. There was significant surface corrosion found on the structural members in the turbine room located immediately below the exhaust stack that sits on the roof of the building over the turbine.	4/10	(20)	10+	2020	Yes	1986
1273	7202	7311	0	GAS TURBINE BUILDING	Service Room:	Service Room:	BLDG3	Visible structural steel in service room is in excellent condition with paint covering the members and no signs of corrosion or major structural deficiencies. The masonry wall dividing the service room and turbine room is in excellent condition on this side.	4/10	(20)	10+	2020	Yes	1986
1273	7202	7311	0	GAS TURBINE BUILDING	Turbine Room	Turbine Room	BLDG4	Structural steel is in good condition except in the immediate vicinity of the exhaust stack. The steel members in this area have moderate corrosion owing to water infiltration around the stack. The masonry wall dividing the service room and turbine room is in excellent condition on this side.	4/10	(20)	10+	2020	Yes	1986
1273	7202	7311	0	GAS TURBINE BUILDING	Generator Room	Generator Room	BLDG5	Visible structural steel in generator room is in good condition except in the immediate vicinity of the exhaust stack. Steel members directly surrounding the exhaust ducting has minor corrosion owing to water infiltration at the roof. This evidenced by rust running down the side of the ducting.	4/10	(20)	10+	2020	Yes	1986
1273	7202	7311	0	GAS TURBINE BUILDING	Battery Room /MCC Room /Control Room	Battery Room	BLDG6	These rooms have their own infill structure that is covered by finishes. There does not appear to be any structural deficiencies in these areas. The building structural steel above these rooms is somewhat visible from the Service Room and looks to be in the same good condition as the steel in that room.	4/10	(20)	10+	2020	Yes	1986
1273	7202	7311	0	GAS TURBINE BUILDING	Roofing	Roofing	BLDG7	The roof of the gas turbine building, specifically in the area around the stack, at the roof liner, shows evidence of moderate corrosion. Unless these areas are repaired there is a risk the deterioration might accelerate and begin to affect the primary structural members. (ie. columns, beams)	4/10	(20)	10/1	2020	No	1986
1273	7202	7311	0	GAS TURBINE BUILDING	Siding	Siding	BLDG8	The siding of the gas turbine building, specifically at the base of the building, show evidence of significant corrosion. Unless these areas are repaired there is a risk the deterioration might accelerate and begin to affect the primary structural members. (ie. columns, beams)	4/10	(20)	10/1	2020	No	1986
1273	7202	7311	0	GAS TURBINE BUILDING	Hoists / Lifting	Hoists / Lifting	BLDG9	There is a main monorail which spans between the Service Room and Turbine Room. This monorail is excellent condition with no signs of corrosion or structural deficiencies. There are two minor lifting beams between the power generator and power turbine. These monorails are in good condition with only minor surface corrosion and no major structural deficiencies. There is a monorail in the generator room which is in excellent conditions with no signs of corrosion or structural deficiencies.	4/10	(20)	10+	2020	Yes	1986
1273	7202	7311	0	GAS TURBINE BUILDING	Exhaust Stack Structure	Exhaust Stack Structure	BLDG10	The steel support frame is good condition with only moderate corrosion, with paint covering the majority of the frame surface and no sign of major structural deficiencies. The structural frame holding up the exhaust cannot be assessed visually as it rests above the main structure obscured from view inside and above the roofline it is covered in flashing. The lifting lugs are in good condition with no signs of major corrosion. The sealant used to weather proof the connection of the frame to the roof is cracking and it should be assumed the frame exhibits similar corrosion as the primary structural steel inside. While not technically a structural item, the exhaust stack itself is extensively corroded above the roof line allowing water to leak into the building causing corrosion.	4/10	(20)	10/0	2020	No	1986

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

2.5.4 Risk Assessment

TABLE 2-28 RISK ASSESSMENT – GAS TURBINE BUILDINGS AND BUILDING M AND E SYSTEM

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset Level 3	Description	Detail	Cond. Summ. ID#	Condition	Major Issues	Remaining Life Years	TECHNO-ECO RISK ASSESS MODEL			SAFETY RISK ASSESS MODEL			Possible Failure Event	Mitigation
										(Insufficient Info - Inspection Required Within (x) Years)	Likeli-hood	Conse-quence	Risk Level	Likeli-hood	Conse-quence	Safety Risk		
1297	7255	272255	7307	BUILDINGS	GAS TURBINE BUILDING													
1273	7202	7311	0	GAS TURBINE BUILDING	Structure - General	Structure	BLDG1	The structural systems that comprise the building are in excellent condition with very little corrosion found and no major structural deficiencies noted. There was significant surface corrosion found on the structural members in the turbine room located immediately below the exhaust stack that sits on the roof of the building over the turbine.	Stack leaks causing structural member surface corrosion.	10+	1	B	Low	1	C	Medium	Structural steel member sigifican corrosion. Stack support failure.	Monitor. Replace/repair leaks in area of stack and check support.
1273	7202	7311	0	GAS TURBINE BUILDING	Service Room:	Service Room:	BLDG2	Visible structural steel in service room is in excellent condition with paint covering the members and no signs of corrosion or major structural deficiencies. The masonry wall dividing the service room and turbine room is in excellent condition on this side.	None	10+	1	A	Low	A	B	LOW	None expected.	Monitor
1273	7202	7311	0	GAS TURBINE BUILDING	Turbine Room	Turbine Room	BLDG3	Structural steel is in good condition except in the immediate vicinity of the exhaust stack. The steel members in this area have moderate corrosion owing to water infiltration around the stack. The masonry wall dividing the service room and turbine room is in excellent condition on this side.	Stack support failure 9eventual).	10+	3	B	Medium	1	C	Medium	Structural steel member sigifican corrosion. Stack support failure.	Monitor. Replace/repair leaks in area of stack and check support.
1273	7202	7311	0	GAS TURBINE BUILDING	Generator Room	Generator Room	BLDG4	Visible structural steel in generator room is in good condition except in the immediate vicinity of the exhaust stack. Steel members directly surrounding the exhaust ducting has minor corrosion owing to water infiltration at the roof. This evidenced by rust running down the side of the ducting.	Stack support failure 9eventual).	10+	3	B	Medium	1	C	Medium	Structural steel member sigifican corrosion. Stack support failure.	Monitor. Replace/repair leaks in area of stack and check support.
1273	7202	7311	0	GAS TURBINE BUILDING	Battery Room /MCC Room /Control Room	Battery Room	BLDG5	These rooms have their own infill structure that is covered by finishes. There does not appear to be any structural deficiencies in these areas. The building structural steel above these rooms is somewhat visible from the Service Room and looks to be in the same good condition as the steel in that room. MCC Requirements require more space.	Regulatory compliance re MCC's and other electrical equipment spacing.	1-Oct	3	B	Medium	3	C	Medium	Electrtical equipment failure in limited space. Regulatory non-compliance.	Increase space when replacing MCC's and/or other electrical room equipment.
1273	7202	7311	0	GAS TURBINE BUILDING	Roofing	Roofing	BLDG6	The roof of the gas turbine building, specifically in the area around the stack, at the roof liner, shows evidence of moderate corrosion. Unless these areas are repaired there is a risk the deterioration might accelerate and begin to affect the primary structural members. (ie. columns, beams)	Roof failure. Water damage in gas turbine causing major damage.	10/1	4	C	High	3	C	Medium	Power turbine water in-leakage causing failure. Stack support failure.	Replace/repair leaks in area of stack and check support. Replace stack.
1273	7202	7311	0	GAS TURBINE BUILDING	Siding	Siding	BLDG7	The siding of the gas turbine building, specifically at the base of the building, show evidence of significant corrosion. Unless these areas are repaired there is a risk the deterioration might accelerate and begin to affect the primary structural members. (ie. columns, beams)	Inleakage of marine salt laden air causing increased corrosion.	10/1	4	A	Medium	4	a	Medium	Structural steel member sigifican corrosion. Stack support failure.	Repair existing holes and sections. Check for asbestos.
1273	7202	7311	0	GAS TURBINE BUILDING	Hoists / Lifting	Hoists / Lifting	BLDG8	There is a main monorail which spans between the Service Room and Turbine Room. This monorail is excellent condition with no signs of corrosion or structural deficiencies. There are two minor lifting beams between the power generator and power turbine. These monorails are in good condition with only minor surface corrosion and no major structural deficiencies. There is a monorail in the generator room which is in excellent conditions with no signs of corrosion or structural deficiencies.	None	10+	1	C	Low	1	C	LOW	Failure during GT part lift.	Monitor
1273	7202	7311	0	GAS TURBINE BUILDING	Exhaust Stack Structure	Exhaust Stack Structure	BLDG9	The steel support frame is good condition with only moderate corrosion, with paint covering the majority of the frame surface and no sign of major structural deficiencies. The structural frame holding up the exhaust cannot be assessed visually as it rests above the main structure obscured from view inside and above the roofline it is covered in flashing. The lifting lugs are in good condition with no signs of major corrosion. The sealant used to weather proof the connection of the frame to the roof is cracking and it should be assumed the frame exhibits similar corrosion as the primary structural steel inside. While not technically a structural item, the exhaust stack itself is extensively corroded above the roof line allowing water to leak into the building causing corrosion.	Water inleakage into power turbine and gearbox area.	10/0	4	C	High	3	C	Medium	Power turbine failure. Stack support failure.	Replace stack and repair roof leaks.

2.5.5 Actions

TABLE 2-29 ACTIONS – GAS TURBINE BUILDINGS AND BUILDING M AND E SYSTEM

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset Level 3	Description	Detail	Action Summ. ID#	Action	Year	Priority
1297	7255	272255	7307	BUILDINGS	GAS TURBINE BUILDING	N/A	BLDG1	Generally repair areas of moisture penetration and air leaks.	2012	2
1273	7202	7311	0	GAS TURBINE BUILDING	Structure - General	Structure	BLDG2	Maintain and monitor	2012	2
1273	7202	7311	0	GAS TURBINE BUILDING	Service Room:	Service Room:	BLDG3	Maintain and monitor	2012	4
1273	7202	7311	0	GAS TURBINE BUILDING	Turbine Room	Turbine Room	BLDG4	Fix roof near stack and stack	2012	1
1273	7202	7311	0	GAS TURBINE BUILDING	Generator Room	Generator Room	BLDG5	Fix roof near stack and stack	2012	1
1273	7202	7311	0	GAS TURBINE BUILDING	Battery Room /MCC Room /Control Room	Battery Room & MCC Room /Control Room	BLDG6	Expand room per current codes when replacing equipment	2012	1
1273	7202	7311	0	GAS TURBINE BUILDING	Roofing	Roofing	BLDG7	Repair roofing around stack. Inspect and maintain balance.	2012	1
1273	7202	7311	0	GAS TURBINE BUILDING	Siding	Siding	BLDG8	Repair current corrosion areas	2012	2
1273	7202	7311	0	GAS TURBINE BUILDING	Hoists / Lifting	Hoists / Lifting	BLDG9	None - Inspect and monitor ongoing		
1273	7202	7311	0	GAS TURBINE BUILDING	Exhaust Stack Structure	Exhaust Stack Structure	BLDG10	Fix roof near stack and stack	2012	1

2.5.6 Life Assessment - Life Cycle Curves (Where Equipment Is Not To Be Overhauled/replaced and Life <2020 and Has Major Unit Operation Impacts)

No Life Cycle Curves are presented. The building with the recommended modifications and repairs can all meet the 2020 end date.

2.5.7 Level 3 Inspections Required

A higher level of inspection is required to confirm the lifting capability of the existing expansion joint / skid which exhaust fan is framed into. It was not confirmed if the existing building contains asbestos. If the roof is disturbed to service/replace the exhaust duct testing should be completed to determine if there is any asbestos in the roofing materials.

Removal of small sections of interior paneling and insulation in areas where corrosion exists in the turbine and power generator rooms should be carried out determine the condition of steel columns in areas where exterior siding has corroded through. These are considered outside of the scope of this assessment and part of the GT overhaul or facility asbestos program,

2.5.8 Capital Enhancements

The suggested capital projects for the GT building and building M and E systems are presented in Table 2-30.

TABLE 2-30 SUGGESTED TYPICAL CAPITAL ENHANCEMENTS – GAS TURBINE BUILDINGS AND BUILDING M AND E SYSTEM

BU # 1	Asset # 2	Asset # 3	Asset # 4	Asset Level 3	Description	Detail	Cond. Summ. ID#	Capital Item	Date	Priority
1297	7255	272255	7307	BUILDINGS	GAS TURBINE BUILDING	N/A	BLDG1	Expansion of building for electrical system requirements and for fuel oil shed.	2012	1
1273	7202	7311	0	GAS TURBINE BUILDING	Structure - General	Structure	BLDG2	No Captial Requirement		
1273	7202	7311	0	GAS TURBINE BUILDING	Service Room:	Service Room:	BLDG3	No Captial Requirement		
1273	7202	7311	0	GAS TURBINE BUILDING	Turbine Room	Turbine Room	BLDG4	No Captial Requirement		
1273	7202	7311	0	GAS TURBINE BUILDING	Generator Room	Generator Room	BLDG5	No Captial Requirement		
1273	7202	7311	0	GAS TURBINE BUILDING	Battery Room /MCC Room /Control Room	Battery Room /MCC Room /Control Room	BLDG6	Expansion of building for electrical system requirements.	2012	1
1273	7202	7311	0	GAS TURBINE BUILDING	Roofing	Roofing	BLDG7	No Captial Requirement		
1273	7202	7311	0	GAS TURBINE BUILDING	Siding	Siding	BLDG8	No Captial Requirement		
1273	7202	7311	0	GAS TURBINE BUILDING	Hoists / Lifting	Hoists / Lifting	BLDG9	No Captial Requirement		
1273	7202	7311	0	GAS TURBINE BUILDING	Exhaust Stack Structure	Exhaust Stack Structure	BLDG10	New stack	2012	1

2.5.9 Capital/Refurbishment Requirements and Costs

The following are the requirements for the complete refurbishment of the building:

- Repair sections of roofing and siding that are corroded and allowing water infiltration. Cost = Approximately $5,000;
- The addition of a building extension to shelter the turbine fuel line mechanical equipment from the elements, likely single span pre-engineered lean-to. Cost = Approximately $40,000;
- Addition of electrical building Cost = Approximately $40,000

2.6 Existing Unit De-Commissioning and Demolition in 2020

No significant incremental costs were identified for existing unit de-commissioning and/or demolition. It was felt that the value of the materials derived from the demolition could offset the cost to the contractor. If required as a sensitivity, then a value such as $40,000 (2011$) might be used, but this would not be expected to either sway the selection of a preferred option, nor impact the overall cost but rather be part of an overall project contingency regardless of any option selected.

2.7 Project Engineering and Management, Owner's Costs

It was assumed that the facility implementation would be undertaken largely as an engineer, procure, construct (EPC) external contract. NL Hydro would be responsible for getting the project approved and the necessary environmental and regulatory approvals. It may be necessary to maintain a schedule for NL Hydro to either procure a power turbine disk or at least a manufacturing slot for the materials and manufacturing pending an EPC which would be free-issued the same (with some guarantee provision exclusions likely).

EPC Costs

For the EPC contractor, the project engineering and management costs are based on the total project costs and a percentage for engineering and for management. For the purposes of this estimate, the engineering costs are estimated to be about 8% of direct costs. The project management and commissioning costs (excluding fuel, NL Hydro staff costs) are estimated to be 8% of direct costs.

Owner's Costs

Owner's costs are not included in the estimates, but are likely to be comparable regardless of the selected option. NL Hydro is assumed to undertake all the necessary environmental and regulatory permitting entirely internally or with some measure of external support (i.e. environmental modeling and engineering support, or full external scope). This cost is also not included but likely on the order of $55,000.

For the actual project implementation, the assumption is that NL Hydro would assume its own costs of this initial development and then assign a project manager for the life of the project to monitor and assure its successful completion. These and other NL Hydro costs (insurance, legal, supply chain, interest, owners' contingency, Holyrood station participation, commissioning fuel, commissioning labour) are not identified or included herein. It is likely that the Owner costs could amount to in the order of 1.5% of directs or about $150,000.

2.8 Existing GTG Refurbishment - Total Cost Estimate

The total existing GT refurbishment cost estimate is shown in Table 2-31. Details are provided in Appendix 7.

TABLE 2-31 EXISTING GTG REFURBISHMENT COST ESTIMATE

Capital cost estimate $1,000 Can 2011

Option Number	**0**
Option	**Existing GT Refurb**
GT/Diesel Cost	$2,950
Civil Works	$224
Electrical Works	$541
BOP Systems	$330
Existing Unit Demolition & Removal	$0
Sub-Total - Directs and Indirects	$4,046
Project Engineering	$324
Project Management	$283
Total	$4,652

+ Standby = Total	$4,825
+ New Rental Stdby = Total	$9,421

Owner's costs were not included, but are expected to be in the order of about 1.5% of direct and indirect cost, plus any taxes and interest where applicable. It should be noted that it may be possible to obtain a used power turbine disk and refurbish it, as opposed to buying a new disk. This may slightly reduce the overall cost slightly. The availability of other parts is considered to be relatively good, but uncertain until a formal tender is issued.

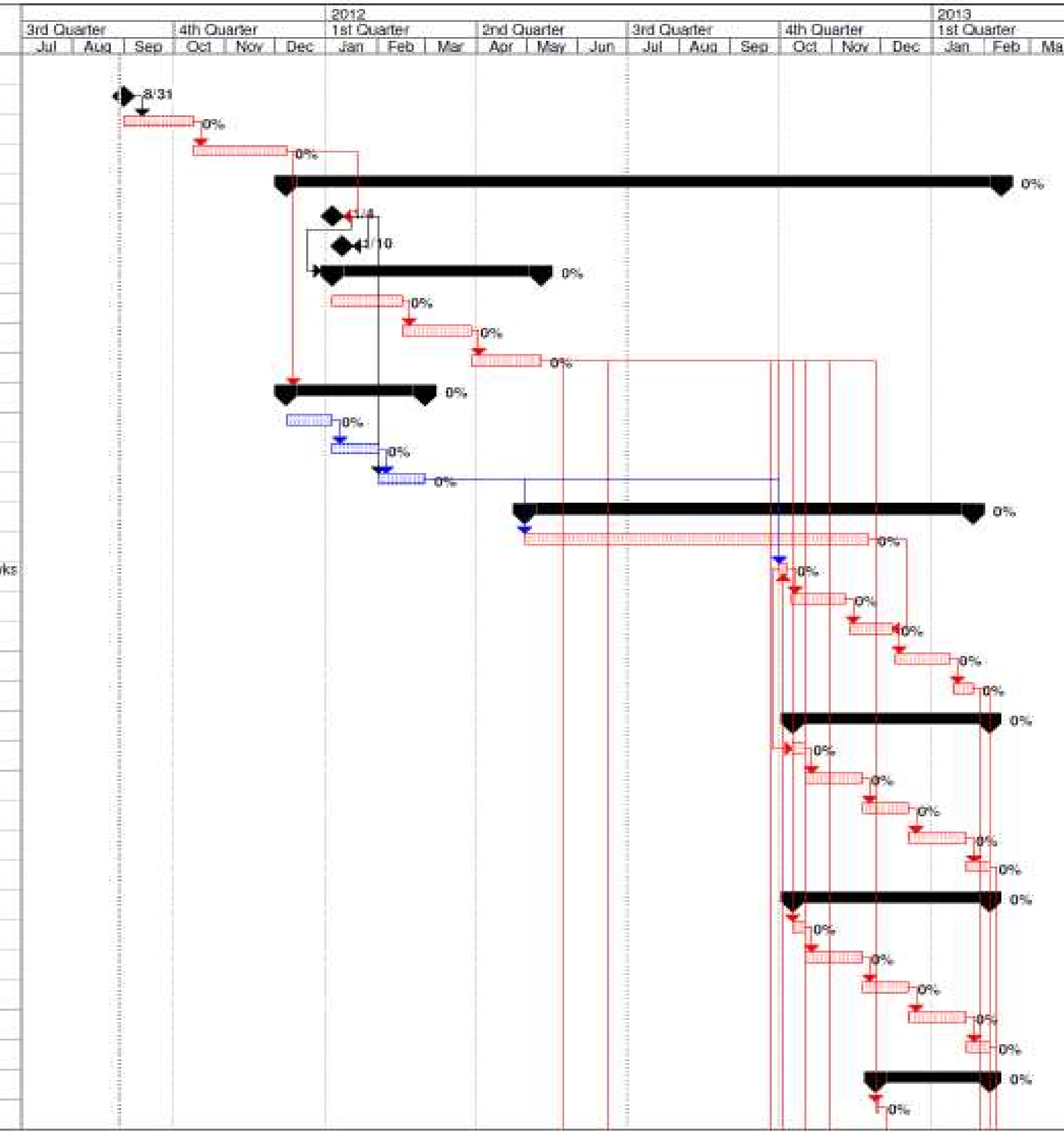
2.8.1 Schedule

The basic "earliest return to service" schedule for the existing GTG unit refurbishment is shown in Figure 2-8 below. Its in-service date is in February 2013. It assumes no replacement unit in six month outage window from September 2012 to February 2013. It is based on an EPC RFP, with the exception of the procurement of a Power Turbine disk which is then free-issued to the EPC contractor.

The outage occurs when Holyrood is normally required to operate. It is likely that the schedule would be allowed to slip to an in-service date in Oct 2013 to have the outage in April to Oct 2013.

FIGURE 2-8 EXISTING GTG REFURBISHMENT – BASE SCHEDULE (NO OUTAGE REPLACEMENT CAPACITY)

ID		Task Name	Duration	Start	Finish	Constraint Type	Predecessors
1							
2		Condition Assessment Study	0 wks	Wed 8/31/11	Wed 8/31/11	ish No Earlier Than	
3		Hydro Internal Capital Budget Proposal Development	6 wks	Thu 9/1/11	Wed 10/12/11	s Soon As Possible	2
4		Submission - Public Utilities Board & Approval	6 wks	Thu 10/13/11	Wed 12/7/11	s Soon As Possible	3
5		**Refurbish Unit**	**308 days**	**Thu 12/8/11**	**Mon 2/11/13**	**Soon As Possible**	
6		Project Limited Notice to proceed (LNTP) Approval	0 days	Wed 1/4/12	Wed 1/4/12	s Soon As Possible	4FF+4 wks
7		Project Full Notice to proceed (NTP)	0 days	Tue 1/10/12	Tue 1/10/12	s Soon As Possible	6FF+4 days
8		**Request for Proposal (RFP) - Engineer/Procure/Co**	**90 days**	**Thu 1/5/12**	**Wed 5/9/12**	**Soon As Possible**	6
9		Prepare	30 days	Thu 1/5/12	Wed 2/15/12	s Soon As Possible	
10		Bid	30 days	Thu 2/16/12	Wed 3/28/12	s Soon As Possible	9
11		Award	30 days	Thu 3/29/12	Wed 5/9/12	s Soon As Possible	10
12		**RFP for Power Turbine Disc Manufacture**	**60 days**	**Thu 12/8/11**	**Wed 2/29/12**	**Soon As Possible**	4
13		Prepare	20 days	Thu 12/8/11	Wed 1/4/12	s Soon As Possible	
14		Bid	20 days	Thu 1/5/12	Wed 2/1/12	s Soon As Possible	13
15		Award	20 days	Thu 2/2/12	Wed 2/29/12	s Soon As Possible	14,6
16		**Power Turbine**	**195 days**	**Mon 4/30/12**	**Fri 1/25/13**	**Soon As Possible**	
17		Manufacture Disc	30 wks	Mon 4/30/12	Fri 11/23/12	As Late As Possible	15
18		Strip and dissassemble plant	1 wk	Mon 10/1/12	Fri 10/5/12	s Soon As Possible	15,42,11FS+2 wks
19		Ship Rotor to overhaul plant	5 wks	Mon 10/8/12	Fri 11/9/12	s Soon As Possible	18
20		Overhaul and balance Rotor	4 wks	Mon 11/12/12	Fri 12/7/12	s Soon As Possible	17FF+2 wks,19
21		Ship Rotor to Holyrood	5 wks	Mon 12/10/12	Fri 1/11/13	s Soon As Possible	20
22		Rebuild and commission unit	2 wks	Mon 1/14/13	Fri 1/25/13	s Soon As Possible	21
23		**Gear Box Overhaul**	**85 days**	**Tue 10/9/12**	**Mon 2/4/13**	**Soon As Possible**	
24		Strip and dissassemble plant	1 wk	Tue 10/9/12	Mon 10/15/12	As Late As Possible	18SS
25		Ship to overhaul plant	5 wks	Tue 10/16/12	Mon 11/19/12	As Late As Possible	24
26		Overhaul and balance Rotor	4 wks	Tue 11/20/12	Mon 12/17/12	As Late As Possible	25
27		Ship to Holyrood	5 wks	Tue 12/18/12	Mon 1/21/13	s Soon As Possible	26
28		Rebuild and commission unit	2 wks	Tue 1/22/13	Mon 2/4/13	s Soon As Possible	27
29		**Avon Gas Generator Overhaul**	**85 days**	**Tue 10/9/12**	**Mon 2/4/13**	**Soon As Possible**	
30		Strip and dissassemble plant	1 wk	Tue 10/9/12	Mon 10/15/12	As Late As Possible	11FS+2 wks
31		Ship Rotor to overhaul plant	5 wks	Tue 10/16/12	Mon 11/19/12	As Late As Possible	30
32		Overhaul and balance Rotor	4 wks	Tue 11/20/12	Mon 12/17/12	As Late As Possible	31
33		Ship Rotor to Holyrood	5 wks	Tue 12/18/12	Mon 1/21/13	s Soon As Possible	32
34		Rebuild and commission unit	2 wks	Tue 1/22/13	Mon 2/4/13	s Soon As Possible	33
35		**Generator Rewind**	**49 days**	**Wed 11/28/12**	**Mon 2/4/13**	**Soon As Possible**	
36		Strip and dissassemble plant	2 days	Wed 11/28/12	Thu 11/29/12	As Late As Possible	11FS+2 wks



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Critical | Task | Baseline | Milestone | Project Summary | Deadline
Critical Split | Split | Baseline Split | Summary Progress | External Tasks
Critical Progress | Task Progress | Baseline Milestone | Summary | External Milestone

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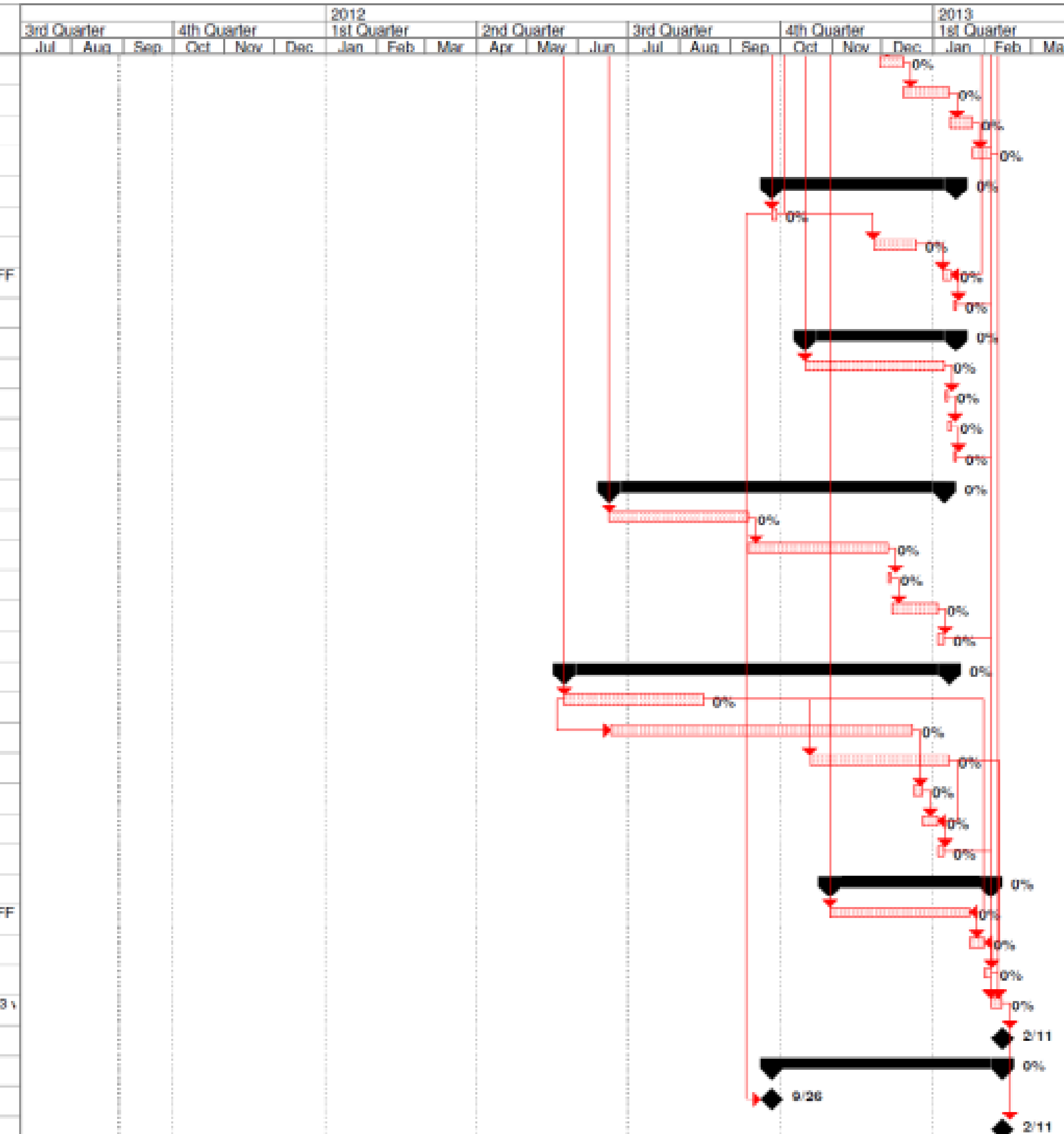
ID	Task Name	Duration	Start	Finish	Constraint Type	Predecessors
37	Ship Rotor to overhaul plant	2 wks	Fri 11/30/12	Thu 12/13/12	As Late As Possible	36
38	Overhaul, rewind, and balance Rotor	4 wks	Fri 12/14/12	Thu 1/10/13	As Late As Possible	37
39	Ship Rotor to Holyrood	2 wks	Fri 1/11/13	Thu 1/24/13	s Soon As Possible	38
40	Rebuild and commission unit	7 days	Fri 1/25/13	Mon 2/4/13	s Soon As Possible	39
41	**Exhaust Stack**	**79 days**	**Wed 9/26/12**	**Mon 1/14/13**	**Soon As Possible**	
42	Remove	3 days	Wed 9/26/12	Fri 9/28/12	As Late As Possible	11FS+2 wks
43	Repair/Replace	4 wks	Mon 11/26/12	Fri 12/21/12	As Late As Possible	42
44	Re-install	5 days	Mon 1/7/13	Fri 1/11/13	As Late As Possible	43FS+2 wks,22FF
45	Commission unit	1 day	Mon 1/14/13	Mon 1/14/13	s Soon As Possible	44
46	**Intake media**	**65 days**	**Tue 10/16/12**	**Mon 1/14/13**	**Soon As Possible**	
47	Order & Manufacture Filter media	12 wks	Tue 10/16/12	Mon 1/7/13	As Late As Possible	11FS+2 wks
48	Remove	2 days	Tue 1/8/13	Wed 1/9/13	As Late As Possible	47
49	Repair/Replace	2 days	Thu 1/10/13	Fri 1/11/13	As Late As Possible	48
50	Commission unit	1 day	Mon 1/14/13	Mon 1/14/13	s Soon As Possible	49
51	**Fuel System Refurbishments**	**144 days**	**Wed 6/20/12**	**Mon 1/7/13**	**Soon As Possible**	
52	Engineer	12 wks	Wed 6/20/12	Tue 9/11/12	As Late As Possible	11FS+2 wks
53	Order, Manufacture, Deliver	12 wks	Wed 9/12/12	Tue 12/4/12	As Late As Possible	52
54	Remove	2 days	Wed 12/5/12	Thu 12/6/12	As Late As Possible	53
55	Repair/Replace	4 wks	Fri 12/7/12	Thu 1/3/13	As Late As Possible	54
56	Commission unit	2 days	Fri 1/4/13	Mon 1/7/13	s Soon As Possible	55
57	**Electrical & Control Systmes**	**166 days**	**Thu 5/24/12**	**Thu 1/10/13**	**Soon As Possible**	
58	Engineer	12 wks	Thu 5/24/12	Wed 8/15/12	As Late As Possible	11FS+2 wks
59	Order & Manufacture Elect & Control Equip	26 wks	Thu 6/21/12	Wed 12/19/12	As Late As Possible	58SS+4 wks
60	GT Building Addition	12 wks	Fri 10/19/12	Thu 1/10/13	As Late As Possible	58
61	Remove Existing	4 days	Thu 12/20/12	Tue 12/25/12	As Late As Possible	59
62	Install New System	7 days	Wed 12/26/12	Thu 1/3/13	As Late As Possible	61,60FF-1 wk
63	Commission unit	2 days	Fri 1/4/13	Mon 1/7/13	s Soon As Possible	62
64	**Building & Systmes**	**69 days**	**Wed 10/31/12**	**Mon 2/4/13**	**Soon As Possible**	
65	Engineer	12 wks	Wed 10/31/12	Tue 1/22/13	As Late As Possible	11FS+2 wks,58FF
66	Modify and Refurbish	7 days	Wed 1/23/13	Thu 1/31/13	As Late As Possible	65,60FF
67	Commission unit	2 days	Fri 2/1/13	Mon 2/4/13	s Soon As Possible	66
68	Complete Unit Test	5 days	Tue 2/5/13	Mon 2/11/13	s Soon As Possible	34,40,22,45FS+3 v
69	Gas Turbine (GT) In-service (I/S)	0 days	Mon 2/11/13	Mon 2/11/13	s Soon As Possible	68
70	**UNIT OUTAGE**	**99 days**	**Wed 9/26/12**	**Mon 2/11/13**	**Soon As Possible**	
71	Unit Outage Start	0 days	Wed 9/26/12	Wed 9/26/12	s Soon As Possible	42SS
72	Unit Outage End	0 days	Mon 2/11/13	Mon 2/11/13	s Soon As Possible	68



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Critical | Critical Split | Critical Progress | Task | Split | Task Progress | Baseline | Baseline Split | Baseline Milestone | Milestone | Summary Progress | Summary | Project Summary | External Tasks | External Milestone | Deadline

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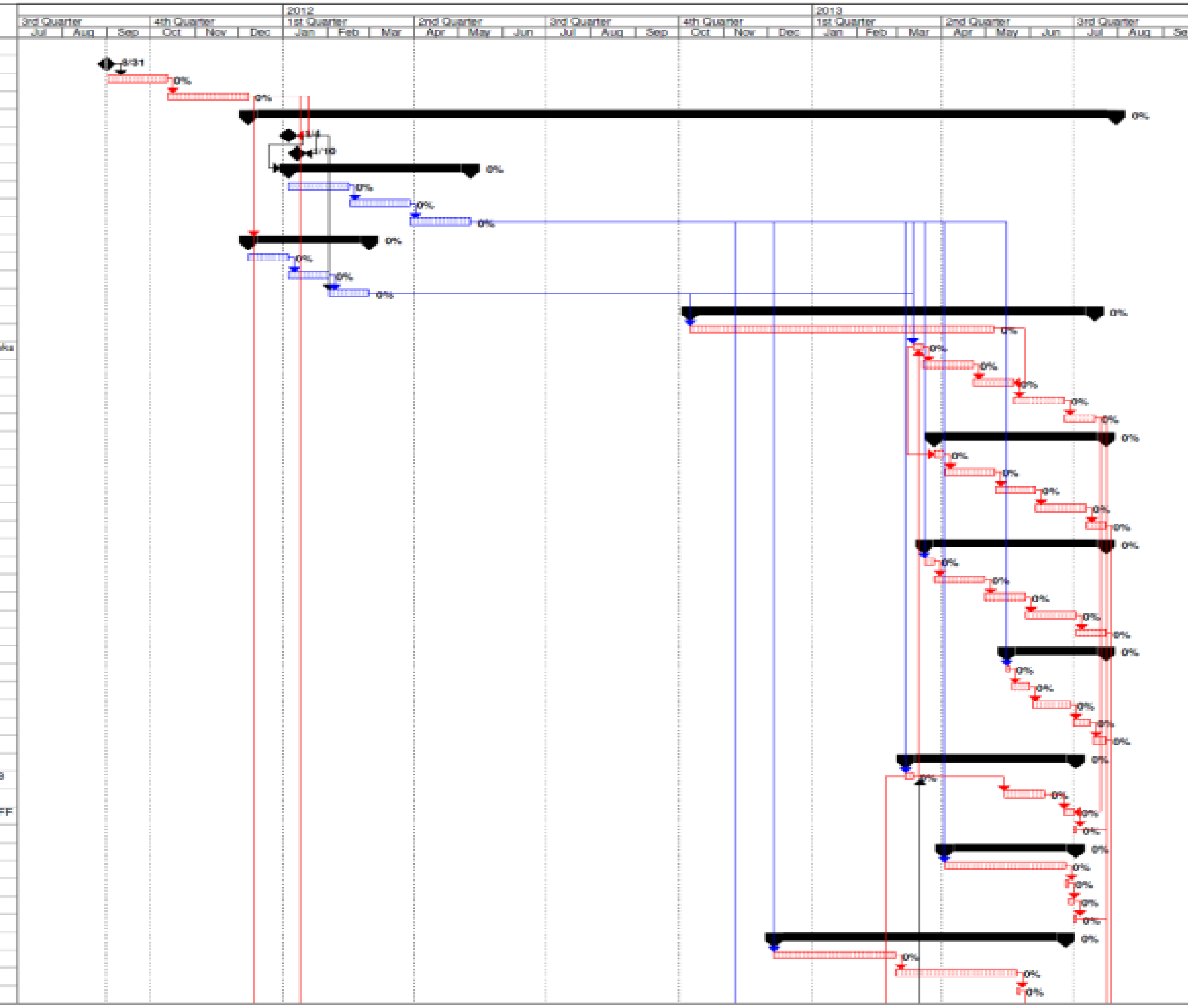
Figure 2-9 presents a variation of the basic "earliest return to service" schedule for the existing GTG unit refurbishment. It includes a replacement nearly new 2 x 5 MW GT during the outage window of the existing unit. The nearly new units would be in-service in March 2013. The resulting existing unit in-service date is end of July 2013, with a five month existing unit outage window from March to July 2013. It also is based on an EPC RFP, with the exception of the procurement of a Power Turbine disk which is free-issued to the EPC contractor. There is no significant period when black start capability is not available. A new 2 x 5MW unit would increase the schedule by about two months.

FIGURE 2-9 EXISTING GTG REFURBISHMENT – ALTERNATE SCHEDULE 1 (NEARLY NEW 2 X 5 MW GT REPLACEMENT DURING OUTAGE)

ID		Task Name	Duration	Start	Finish	Constraint Type	Predecessors
1							
2		Condition Assessment Study	0 wks	Wed 8/31/11	Wed 8/31/11	Finish No Earlier Than	
3		Hydro Internal Capital Budget Proposal Development	6 wks	Thu 9/1/11	Wed 10/12/11	As Soon As Possible	2
4		Submission - Public Utilities Board & Approval	8 wks	Thu 10/13/11	Wed 12/7/11	As Soon As Possible	3
5		**Refurbish Unit**	**429 days**	**Thu 12/8/11**	**Tue 7/30/13**	**As Soon As Possible**	
6		Project Limited Notice to proceed (LNTP) Approval	0 days	Wed 1/4/12	Wed 1/4/12	As Soon As Possible	4FF+4 wks
7		Project Full Notice to proceed (NTP)	0 days	Tue 1/10/12	Tue 1/10/12	As Soon As Possible	6FF+4 days
8		**Request for Proposal (RFP) - Engineer/Procure/Cor**	**90 days**	**Thu 1/5/12**	**Wed 5/9/12**	**As Soon As Possible**	**6**
9		Prepare	30 days	Thu 1/5/12	Wed 2/15/12	As Soon As Possible	
10		Bid	30 days	Thu 2/16/12	Wed 3/28/12	As Soon As Possible	9
11		Award	30 days	Thu 3/29/12	Wed 5/9/12	As Soon As Possible	10
12		**RFP for Power Turbine Disc Manufacture**	**60 days**	**Thu 12/8/11**	**Wed 2/29/12**	**As Soon As Possible**	**4**
13		Prepare	20 days	Thu 12/8/11	Wed 1/4/12	As Soon As Possible	
14		Bid	20 days	Thu 1/5/12	Wed 2/1/12	As Soon As Possible	13
15		Award	20 days	Thu 2/2/12	Wed 2/29/12	As Soon As Possible	14,6
16		**Power Turbine**	**200 days**	**Tue 10/9/12**	**Mon 7/15/13**	**As Soon As Possible**	
17		Manufacture Disc	30 wks	Tue 10/9/12	Mon 5/6/13	As Late As Possible	15
18		Strip and disassemble plant	1 wk	Tue 3/12/13	Mon 3/18/13	As Late As Possible	15,42,11FS-2 wks
19		Ship Rotor to overhaul plant	5 wks	Tue 3/19/13	Mon 4/22/13	As Late As Possible	18
20		Overhaul and balance Rotor	4 wks	Tue 4/23/13	Mon 5/20/13	As Late As Possible	17FF+2 wks,19
21		Ship Rotor to Holyrood	5 wks	Tue 5/21/13	Mon 6/24/13	As Soon As Possible	20
22		Rebuild and commission unit	3 wks	Tue 6/25/13	Mon 7/15/13	As Soon As Possible	21
23		**Gear Box Overhaul**	**85 days**	**Wed 3/27/13**	**Tue 7/23/13**	**As Soon As Possible**	
24		Strip and disassemble plant	1 wk	Wed 3/27/13	Tue 4/2/13	As Late As Possible	18SS
25		Ship to overhaul plant	5 wks	Wed 4/3/13	Tue 5/7/13	As Late As Possible	24
26		Overhaul and balance Rotor	4 wks	Wed 5/8/13	Tue 6/4/13	As Late As Possible	25
27		Ship to Holyrood	5 wks	Wed 6/5/13	Tue 7/9/13	As Soon As Possible	26
28		Rebuild and commission unit	2 wks	Wed 7/10/13	Tue 7/23/13	As Soon As Possible	27
29		**Avon Gas Generator Overhaul**	**90 days**	**Wed 3/20/13**	**Tue 7/23/13**	**As Soon As Possible**	
30		Strip and disassemble plant	1 wk	Wed 3/20/13	Tue 3/26/13	As Late As Possible	11FS+2 wks
31		Ship Rotor to overhaul plant	5 wks	Wed 3/27/13	Tue 4/30/13	As Late As Possible	30
32		Overhaul and balance Rotor	4 wks	Wed 5/1/13	Tue 5/28/13	As Late As Possible	31
33		Ship Rotor to Holyrood	5 wks	Wed 5/29/13	Tue 7/2/13	As Soon As Possible	32
34		Rebuild and commission unit	3 wks	Wed 7/3/13	Tue 7/23/13	As Soon As Possible	33
35		**Generator Rewind**	**49 days**	**Thu 5/16/13**	**Tue 7/23/13**	**As Soon As Possible**	
36		Strip and disassemble plant	2 days	Thu 5/16/13	Fri 5/17/13	As Late As Possible	11FS+2 wks
37		Ship Rotor to overhaul plant	2 wks	Mon 5/20/13	Fri 5/31/13	As Late As Possible	36
38		Overhaul, rewind, and balance Rotor	4 wks	Mon 6/3/13	Fri 6/28/13	As Late As Possible	37
39		Ship Rotor to Holyrood	2 wks	Mon 7/1/13	Fri 7/12/13	As Soon As Possible	38
40		Rebuild and commission unit	7 days	Mon 7/15/13	Tue 7/23/13	As Soon As Possible	39
41		**Exhaust Stack**	**84 days**	**Thu 3/7/13**	**Tue 7/2/13**	**As Soon As Possible**	
42		Remove	3 days	Thu 3/7/13	Mon 3/11/13	As Late As Possible	11FS+2 wks,108
43		Repair/Replace	4 wks	Tue 5/14/13	Mon 6/10/13	As Late As Possible	42
44		Re-install	5 days	Tue 6/25/13	Mon 7/1/13	As Late As Possible	43FS+2 wks,22FF
45		Commission unit	1 day	Tue 7/2/13	Tue 7/2/13	As Soon As Possible	44
46		**Intake media**	**65 days**	**Wed 4/3/13**	**Tue 7/2/13**	**As Soon As Possible**	
47		Order & Manufacture Filter media	12 wks	Wed 4/3/13	Tue 6/25/13	As Late As Possible	11FS+2 wks
48		Remove	2 days	Wed 6/26/13	Thu 6/27/13	As Late As Possible	47
49		Repair/Replace	2 days	Fri 6/28/13	Mon 7/1/13	As Late As Possible	48
50		Commission unit	1 day	Tue 7/2/13	Tue 7/2/13	As Soon As Possible	49
51		**Fuel System Refurbishments**	**144 days**	**Thu 12/6/12**	**Tue 6/25/13**	**As Soon As Possible**	
52		Engineer	12 wks	Thu 12/6/12	Wed 2/27/13	As Late As Possible	11FS+2 wks
53		Order, Manufacture, Deliver	12 wks	Thu 2/28/13	Wed 5/22/13	As Late As Possible	52
54		Remove	2 days	Thu 5/23/13	Fri 5/24/13	As Late As Possible	53



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Critical | Critical Split | Critical Progress | Task | Split | Task Progress | Baseline | Baseline Split | Baseline Milestone | Milestone | Summary Progress | Summary | Project Summary | External Tasks | External Milestone | Deadline

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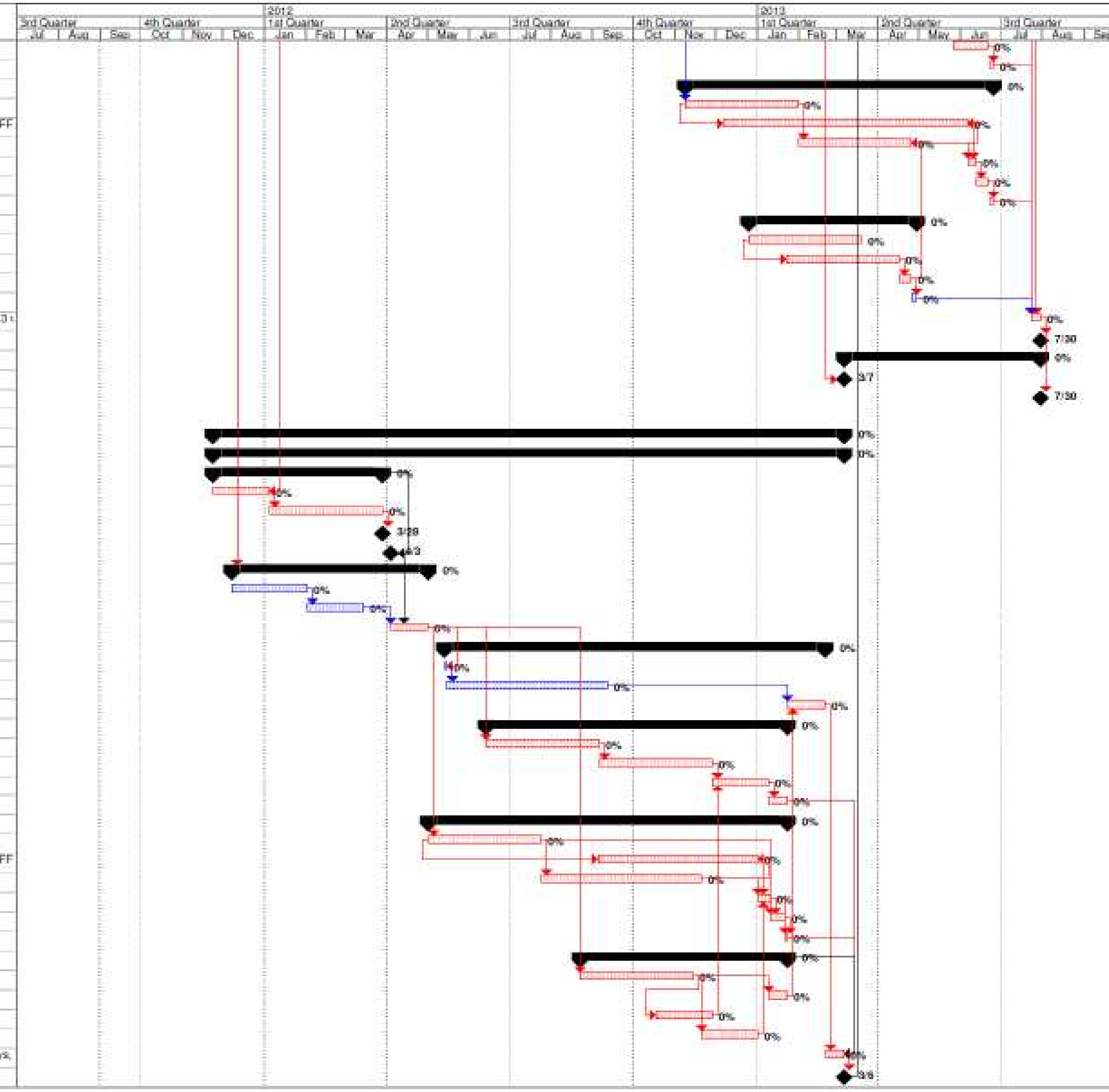
ID		Task Name	Duration	Start	Finish	Constraint Type	Predecessors
55		Repair/Replace	4 wks	Mon 5/27/13	Fri 6/21/13	As Late As Possible	54
56		Commission unit	2 days	Mon 6/24/13	Tue 6/25/13	As Soon As Possible	55
57		**Electrical & Control Systmes**	**163 days**	**Fri 11/9/12**	**Tue 6/25/13**	**As Soon As Possible**	
58		Engineer	12 wks	Fri 11/9/12	Thu 1/31/13	As Late As Possible	11FS+2 wks
59		Order & Manufacture Elect & Control Equip	26 wks	Fri 12/7/12	Thu 6/6/13	As Late As Possible	58SS+4 wks,60FF
60		GT Building Addition	12 wks	Fri 2/1/13	Thu 4/25/13	As Late As Possible	58,67FF
61		Remove Existing	4 days	Fri 6/7/13	Wed 6/12/13	As Late As Possible	60,59
62		Install New System	7 days	Thu 6/13/13	Fri 6/21/13	As Late As Possible	61
63		Commission unit	2 days	Mon 6/24/13	Tue 6/25/13	As Soon As Possible	62
64		**Building & Systmes**	**89 days**	**Wed 12/26/12**	**Mon 4/29/13**	**As Soon As Possible**	
65		Engineer	12 wks	Wed 12/26/12	Tue 3/19/13	As Late As Possible	
66		Order & Manufacture Elect & Control Equip	12 wks	Wed 1/23/13	Tue 4/16/13	As Late As Possible	65SS+4 wks
67		Modify and Refurbish	7 days	Wed 4/17/13	Thu 4/25/13	As Late As Possible	66
68		Commission unit	2 days	Fri 4/26/13	Mon 4/29/13	As Soon As Possible	67
69		Complete Unit Test	5 days	Wed 7/24/13	Tue 7/30/13	As Soon As Possible	34,40,22,45FS-3
70		Gas Turbine (GT) In-service (I/S)	0 days	Tue 7/30/13	Tue 7/30/13	As Soon As Possible	69
71		**UNIT OUTAGE**	**104 days**	**Thu 3/7/13**	**Tue 7/30/13**	**As Soon As Possible**	
72		Unit Outage Start	0 days	Thu 3/7/13	Thu 3/7/13	As Soon As Possible	42SS
73		Unit Outage End	0 days	Tue 7/30/13	Tue 7/30/13	As Soon As Possible	69
74							
75		**REPLACEMENT UNIT**	**335 days**	**Thu 11/24/11**	**Wed 3/6/13**	**As Soon As Possible**	
76		**Nearly New gas Turbine (GT) Generator Units**	**335 days**	**Thu 11/24/11**	**Wed 3/6/13**	**As Soon As Possible**	
77		**Project Environmental & Regulatory Approvals**	**90 days**	**Thu 11/24/11**	**Wed 3/28/12**	**As Soon As Possible**	
78		Prepare Dispersion Modelling & Submission	30 days	Thu 11/24/11	Wed 1/4/12	As Soon As Possible	4FF+4 wks
79		Regulatory Review and Approval	60 days	Thu 1/5/12	Wed 3/28/12	As Soon As Possible	78
80		Environmental Approval	0 days	Wed 3/28/12	Wed 3/28/12	As Soon As Possible	79
81		Project Full Release	0 days	Tue 4/3/12	Tue 4/3/12	As Soon As Possible	77FF+4 days
82		**Request for Proposal (RFP) for Engineer/Proc**	**104 days**	**Thu 12/8/11**	**Tue 5/1/12**	**As Soon As Possible**	**4**
83		Prepare	40 days	Thu 12/8/11	Wed 2/1/12	As Soon As Possible	
84		Bid	6 wks	Thu 2/2/12	Wed 3/14/12	As Soon As Possible	83
85		Award	20 days	Wed 4/4/12	Tue 5/1/12	As Soon As Possible	81,84
86		**Nearly New GT or Diesel Engine Generator**	**203 days**	**Mon 5/14/12**	**Wed 2/20/13**	**As Soon As Possible**	
87		Award GT/Diesel Engine Contract	2 days	Mon 5/14/12	Tue 5/15/12	As Soon As Possible	85FF+10 days
88		Manufacture & Deliver Transportable Engine	17 wks	Wed 5/16/12	Tue 9/11/12	As Soon As Possible	87
89		Install and Commission	4 wks	Thu 1/24/13	Wed 2/20/13	As Soon As Possible	88,104
90		**Fuel System**	**160 days**	**Thu 6/14/12**	**Wed 1/23/13**	**As Soon As Possible**	
91		Engineer	12 wks	Thu 6/14/12	Wed 9/5/12	As Late As Possible	85
92		Order, Manufacture, Deliver	12 wks	Thu 9/6/12	Wed 11/28/12	As Late As Possible	91
93		Install new fuel lines and receiving system	6 wks	Thu 11/29/12	Wed 1/9/13	As Late As Possible	92,105
94		Commission System	2 wks	Thu 1/10/13	Wed 1/23/13	As Late As Possible	93
95		**Electrical & Control Systmes**	**191 days**	**Wed 5/2/12**	**Wed 1/23/13**	**As Soon As Possible**	
96		Engineer	12 wks	Wed 5/2/12	Tue 7/24/12	As Late As Possible	85
97		Order & Manufacture Elect & Control (E&C) E	17 wks	Wed 9/5/12	Tue 1/1/13	As Late As Possible	96SS+4 wks,98FF
98		Electrical Building Manufacture, Delivery, Ins	17 wks	Wed 7/25/12	Tue 11/20/12	As Late As Possible	96
99		Install New System	7 days	Wed 1/2/13	Thu 1/10/13	As Late As Possible	97,98,106
100		RE-align Existing Plant Systems	7 days	Fri 1/11/13	Mon 1/21/13	As Late As Possible	96,99
101		Commission unit	2 days	Tue 1/22/13	Wed 1/23/13	As Soon As Possible	99,100
102		**Site Civil Work**	**110 days**	**Thu 8/23/12**	**Wed 1/23/13**	**As Soon As Possible**	
103		Engineer	12 wks	Thu 8/23/12	Wed 11/14/12	As Late As Possible	85
104		Generator area clearing and civil	2 wks	Thu 1/10/13	Wed 1/23/13	As Late As Possible	103FS-6 wks
105		Fuel line civil work	6 wks	Thu 10/18/12	Wed 11/28/12	As Late As Possible	103FS-4 wks
106		Electrical an contro cable civil work	6 wks	Wed 11/21/12	Tue 1/1/13	As Late As Possible	103FS-2 wks
107		Complete Unit Test	10 days	Thu 2/21/13	Wed 3/6/13	As Soon As Possible	89,94FF+30 days,
108		GT In-Service (I/S)	0 days	Wed 3/6/13	Wed 3/6/13	As Soon As Possible	107



Project: Project1 Exist & Repla near ne
Date: Wed 8/31/11

Critical · Critical Split · Critical Progress · Task · Split · Task Progress · Baseline · Baseline Split · Baseline Milestone · Milestone · Summary Progress · Summary · Project Summary · External Tasks · External Milestone · Deadline

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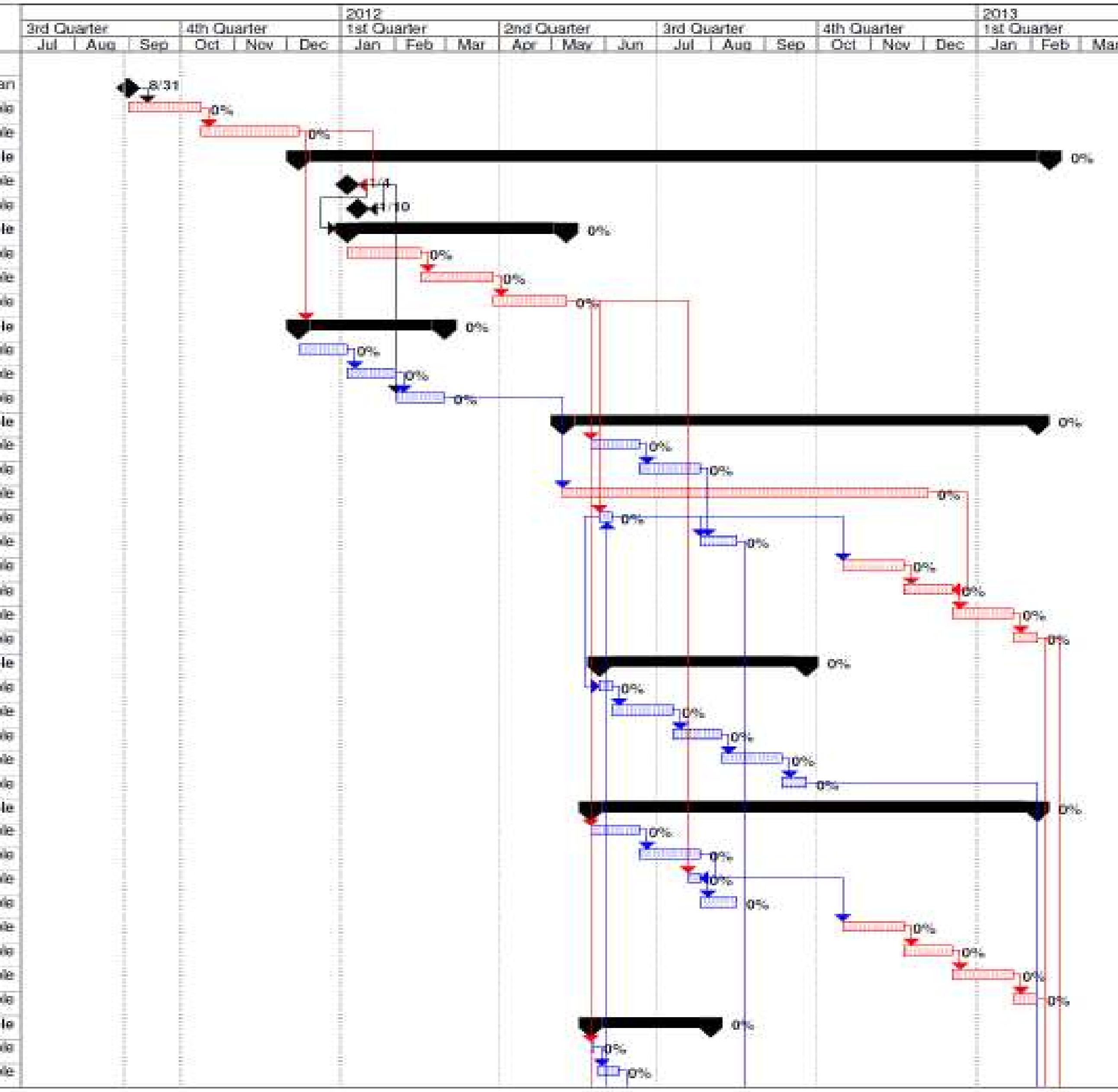
Figure 2-10 presents a second variation of the basic “earliest return to service” schedule for the existing GTG unit refurbishment. It assumes leased used replacements parts for the existing GT unit (the gas generator, the power turbine) to minimize the outage window, but does not. The in-service date is still February 2013, but with a longer outage window of 9 months from May 2012 to February 2013. The outage also occurs when Holyrood is normally required to operate, and given its duration would not be impacted by schedule shifting.

FIGURE 2-10 EXISTING GTG REFURBISHMENT – ALTERNATE SCHEDULE 2 (LEASED USED GAS GENERATOR AND POWER TURBINE DURING OUTAGE)

ID	Task Name	Duration	Start	Finish	Constraint Type
1					
2	Condition Assessment Study	0 wks	Wed 8/31/11	Wed 8/31/11	Finish No Earlier Than
3	Hydro Internal Capital Budget Proposal Development	6 wks	Thu 9/1/11	Wed 10/12/11	As Soon As Possible
4	Submission - Public Utilities Board & Approval	8 wks	Thu 10/13/11	Wed 12/7/11	As Soon As Possible
5	**Refurbish Unit**	**308 days**	**Thu 12/8/11**	**Mon 2/11/13**	**As Soon As Possible**
6	Project Limited Notice to proceed (LNTP) Approval	0 days	Wed 1/4/12	Wed 1/4/12	As Soon As Possible
7	Project Full Notice to proceed (NTP)	0 days	Tue 1/10/12	Tue 1/10/12	As Soon As Possible
8	**Request for Proposal (RFP) - Engineer/Procure/Construct (E**	**90 days**	**Thu 1/5/12**	**Wed 5/9/12**	**As Soon As Possible**
9	Prepare	30 days	Thu 1/5/12	Wed 2/15/12	As Soon As Possible
10	Bid	30 days	Thu 2/16/12	Wed 3/28/12	As Soon As Possible
11	Award	30 days	Thu 3/29/12	Wed 5/9/12	As Soon As Possible
12	**RFP for Power Turbine Disc Manufacture**	**60 days**	**Thu 12/8/11**	**Wed 2/29/12**	**As Soon As Possible**
13	Prepare	20 days	Thu 12/8/11	Wed 1/4/12	As Soon As Possible
14	Bid	20 days	Thu 1/5/12	Wed 2/1/12	As Soon As Possible
15	Award	20 days	Thu 2/2/12	Wed 2/29/12	As Soon As Possible
16	**Power Turbine**	**195 days**	**Tue 5/8/12**	**Mon 2/4/13**	**As Soon As Possible**
17	Procure Lease Disc and PT Assembly	4 wks	Thu 5/24/12	Wed 6/20/12	As Soon As Possible
18	Refurbish PT Replacement	5 wks	Thu 6/21/12	Wed 7/25/12	As Soon As Possible
19	Manufacture NEW PT Disc	30 wks	Tue 5/8/12	Mon 12/3/12	As Late As Possible
20	Strip and dissassemble plant	1 wk	Tue 5/29/12	Mon 6/4/12	As Soon As Possible
21	Rebuild and commission unit - Lease part	3 wks	Thu 7/26/12	Wed 8/15/12	As Soon As Possible
22	Ship Rotor to overhaul plant	5 wks	Tue 10/16/12	Mon 11/19/12	As Late As Possible
23	Overhaul and balance Rotor	4 wks	Tue 11/20/12	Mon 12/17/12	As Late As Possible
24	Ship Rotor to Holyrood	5 wks	Tue 12/18/12	Mon 1/21/13	As Soon As Possible
25	Replace lease part, rebuild and commission unit	2 wks	Tue 1/22/13	Mon 2/4/13	As Soon As Possible
26	**Gear Box Overhaul**	**85 days**	**Tue 5/29/12**	**Mon 9/24/12**	**As Soon As Possible**
27	Strip and dissassemble plant	1 wk	Tue 5/29/12	Mon 6/4/12	As Soon As Possible
28	Ship to overhaul plant	5 wks	Tue 6/5/12	Mon 7/9/12	As Soon As Possible
29	Overhaul and balance Rotor	4 wks	Tue 7/10/12	Mon 8/6/12	As Soon As Possible
30	Ship to Holyrood	5 wks	Tue 8/7/12	Mon 9/10/12	As Soon As Possible
31	Rebuild and commission unit	2 wks	Tue 9/11/12	Mon 9/24/12	As Soon As Possible
32	**Avon Gas Generator Overhaul**	**183 days**	**Thu 5/24/12**	**Mon 2/4/13**	**As Soon As Possible**
33	Procure Lease Disc and PT Assembly	4 wks	Thu 5/24/12	Wed 6/20/12	As Soon As Possible
34	Refurbish PT Replacement	5 wks	Thu 6/21/12	Wed 7/25/12	As Soon As Possible
35	Strip and dissassemble plant	1 wk	Thu 7/19/12	Wed 7/25/12	As Soon As Possible
36	Rebuild and commission unit - Lease part	3 wks	Thu 7/26/12	Wed 8/15/12	As Soon As Possible
37	Ship Rotor to overhaul plant	5 wks	Tue 10/16/12	Mon 11/19/12	As Late As Possible
38	Overhaul and balance Rotor	4 wks	Tue 11/20/12	Mon 12/17/12	As Late As Possible
39	Ship Rotor to Holyrood	5 wks	Tue 12/18/12	Mon 1/21/13	As Soon As Possible
40	Replace lease part, rebuild and commission unit	2 wks	Tue 1/22/13	Mon 2/4/13	As Soon As Possible
41	**Generator Rewind**	**49 days**	**Thu 5/24/12**	**Tue 7/31/12**	**As Soon As Possible**
42	Strip and dissassemble plant	2 days	Thu 5/24/12	Fri 5/25/12	As Soon As Possible
43	Ship Rotor to overhaul plant	2 wks	Mon 5/28/12	Fri 6/8/12	As Soon As Possible



Project: Project1 Exist & Repla Lease
Date: Mon 8/29/11

Critical | Task | Baseline | Milestone | Project Summary | Deadline
Critical Split | Split | Baseline Split | Summary Progress | External Tasks
Critical Progress | Task Progress | Baseline Milestone | Summary | External Milestone

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Holyrood Thermal Generating Station
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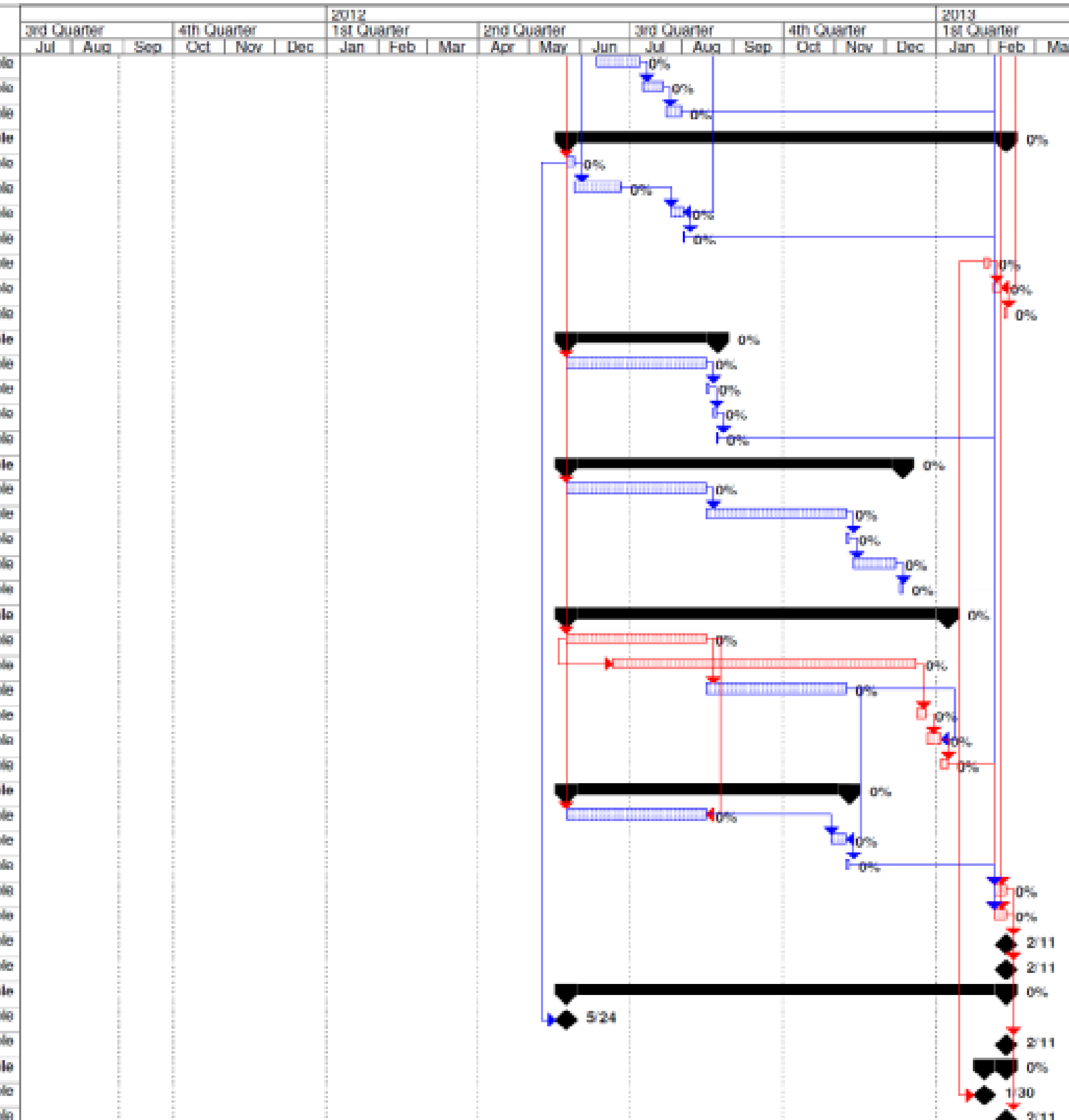
ID		Task Name	Duration	Start	Finish	Constraint Type
44		Overhaul, rewind, and balance Rotor	4 wks	Mon 6/11/12	Fri 7/6/12	As Soon As Possible
45		Ship Rotor to Holyrood	2 wks	Mon 7/9/12	Fri 7/20/12	As Soon As Possible
46		Rebuild and commission unit	7 days	Mon 7/23/12	Tue 7/31/12	As Soon As Possible
47		**Exhaust Stack**	**188 days**	**Thu 5/24/12**	**Mon 2/11/13**	**As Soon As Possible**
48		Remove	3 days	Thu 5/24/12	Mon 5/28/12	As Soon As Possible
49		Repair/Replace	4 wks	Tue 5/29/12	Mon 6/25/12	As Soon As Possible
50		Re-install	5 days	Thu 7/26/12	Wed 8/1/12	As Soon As Possible
51		Commission unit	1 day	Thu 8/2/12	Thu 8/2/12	As Soon As Possible
52		Remove new stack	3 days	Wed 1/30/13	Fri 2/1/13	As Late As Possible
53		Re-install	5 days	Mon 2/4/13	Fri 2/8/13	As Late As Possible
54		Commission unit	1 day	Mon 2/11/13	Mon 2/11/13	As Soon As Possible
55		**Intake media**	**65 days**	**Thu 5/24/12**	**Wed 8/22/12**	**As Soon As Possible**
56		Order & Manufacture Filter media	12 wks	Thu 5/24/12	Wed 8/15/12	As Soon As Possible
57		Remove	2 days	Thu 8/16/12	Fri 8/17/12	As Soon As Possible
58		Repair/Replace	2 days	Mon 8/20/12	Tue 8/21/12	As Soon As Possible
59		Commission unit	1 day	Wed 8/22/12	Wed 8/22/12	As Soon As Possible
60		**Fuel System Refurbishments**	**144 days**	**Thu 5/24/12**	**Tue 12/11/12**	**As Soon As Possible**
61		Engineer	12 wks	Thu 5/24/12	Wed 8/15/12	As Soon As Possible
62		Order, Manufacture, Deliver	12 wks	Thu 8/16/12	Wed 11/7/12	As Soon As Possible
63		Remove	2 days	Thu 11/8/12	Fri 11/9/12	As Soon As Possible
64		Repair/Replace	4 wks	Mon 11/12/12	Fri 12/7/12	As Soon As Possible
65		Commission unit	2 days	Mon 12/10/12	Tue 12/11/12	As Soon As Possible
66		**Electrical & Control Systmes**	**163 days**	**Thu 5/24/12**	**Mon 1/7/13**	**As Soon As Possible**
67		Engineer	12 wks	Thu 5/24/12	Wed 8/15/12	As Soon As Possible
68		Order & Manufacture Elect & Control Equip	26 wks	Thu 6/21/12	Wed 12/19/12	As Soon As Possible
69		GT Building Addition	12 wks	Thu 8/16/12	Wed 11/7/12	As Soon As Possible
70		Remove Existing	4 days	Thu 12/20/12	Tue 12/25/12	As Soon As Possible
71		Install New System	7 days	Wed 12/26/12	Thu 1/3/13	As Soon As Possible
72		Commission unit	2 days	Fri 1/4/13	Mon 1/7/13	As Soon As Possible
73		**Building & Systmes**	**122 days**	**Thu 5/24/12**	**Fri 11/9/12**	**As Soon As Possible**
74		Engineer	12 wks	Thu 5/24/12	Wed 8/15/12	As Soon As Possible
75		Modify and Refurbish	7 days	Tue 10/30/12	Wed 11/7/12	As Soon As Possible
76		Commission unit	2 days	Thu 11/8/12	Fri 11/9/12	As Soon As Possible
77		Complete Unit Test - Lease Parts	5 days	Tue 2/5/13	Mon 2/11/13	As Soon As Possible
78		Complete Unit Test - Original Replacement	5 days	Tue 2/5/13	Mon 2/11/13	As Soon As Possible
79		Gas Turbine (GT) In-service (I/S) - Lease Parts	0 days	Mon 2/11/13	Mon 2/11/13	As Soon As Possible
80		Gas Turbine (GT) In-service (I/S) - Original	0 days	Mon 2/11/13	Mon 2/11/13	As Soon As Possible
81		**UNIT OUTAGE -Lease Parts**	**188 days**	**Thu 5/24/12**	**Mon 2/11/13**	**As Soon As Possible**
82		Unit Outage Start	0 days	Thu 5/24/12	Thu 5/24/12	As Soon As Possible
83		Unit Outage End	0 days	Mon 2/11/13	Mon 2/11/13	As Soon As Possible
84		**UNIT OUTAGE - Original**	**9 days**	**Wed 1/30/13**	**Mon 2/11/13**	**As Soon As Possible**
85		Unit Outage Start	0 days	Wed 1/30/13	Wed 1/30/13	As Soon As Possible
86		Unit Outage End	0 days	Mon 2/11/13	Mon 2/11/13	As Soon As Possible



Project: Project1 Exist & Repla Lease
Date: Mon 8/29/11

Critical | Critical Split | Critical Progress | Task | Split | Task Progress | Baseline | Baseline Split | Baseline Milestone | Milestone | Summary Progress | Summary | Project Summary | External Tasks | External Milestone | Deadline

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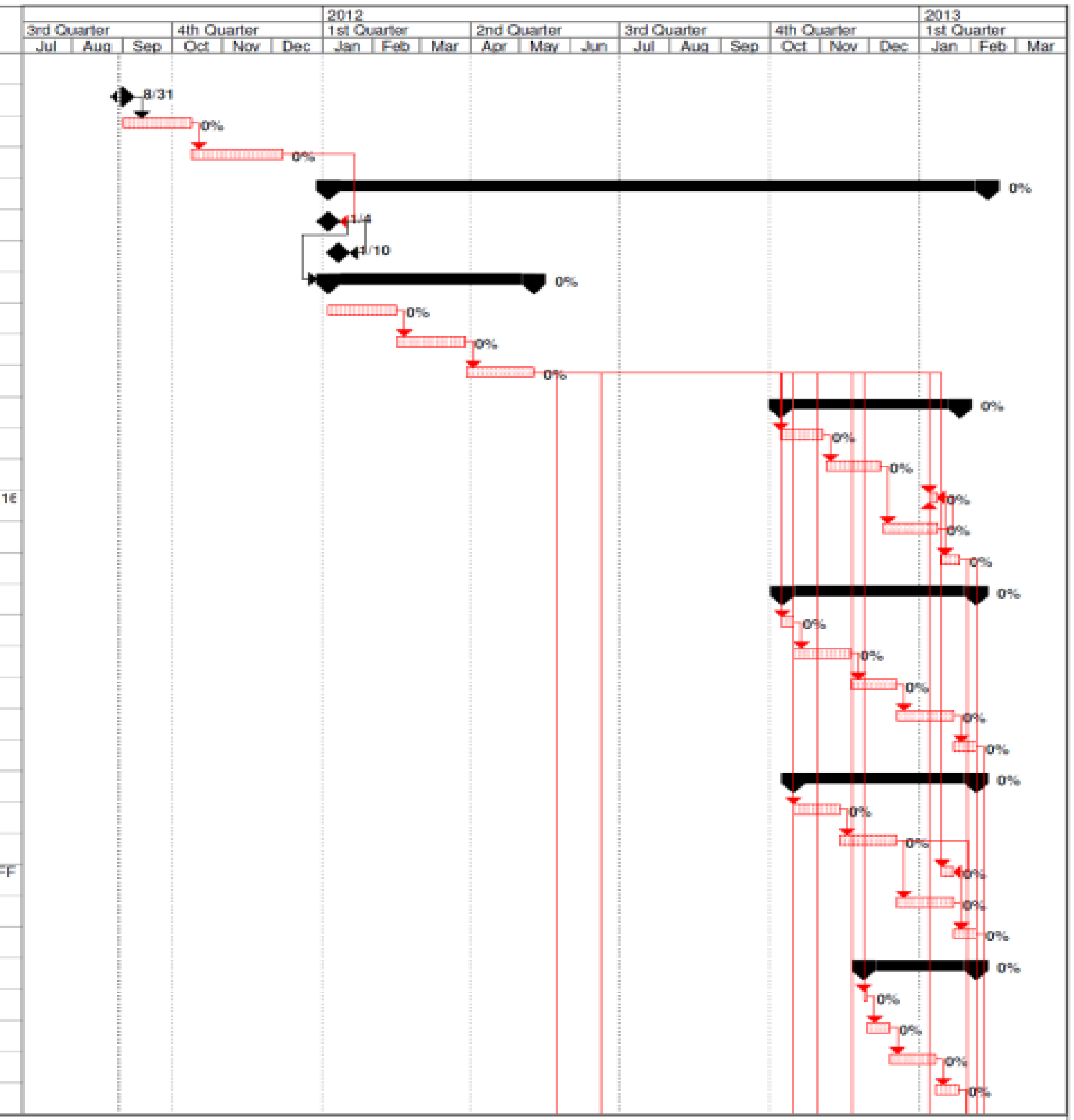
Figure 2-11 presents a third variation of the basic "earliest return to service" schedule for the existing GTG unit refurbishment. It assumes the purchase and refurbishment for use of used replacements parts for the existing GT unit (the gas generator, the power turbine) to minimize the outage window. Its in-service date is February 2013, but with an outage window of only four months from November 2012 to February 2013. The outage also occurs when Holyrood is normally required to operate, and the actual schedule would likely be shifted six months to allow for a May 2013 to August 2013 outage and August 2013 in-service.

FIGURE 2-11 EXISTING GTG REFURBISHMENT – ALTERNATE SCHEDULE 3 (USE OF PROCURED AND REFURBISHED GAS GENERATOR AND POWER TURBINE DURING OUTAGE)

ID		Task Name	Duration	Start	Finish	Constraint Type	Predecessors
1							
2		Condition Assessment Study	0 wks	Wed 8/31/11	Wed 8/31/11	Finish No Earlier Than	
3		Hydro Internal Capital Budget Proposal Development	6 wks	Thu 9/1/11	Wed 10/12/11	As Soon As Possible	2
4		Submission - Public Utilities Board & Approval	8 wks	Thu 10/13/11	Wed 12/7/11	As Soon As Possible	3
5		**Refurbish Unit**	**288 days**	**Wed 1/4/12**	**Mon 2/11/13**	**As Soon As Possible**	
6		Project Limited Notice to proceed (LNTP) Approval	0 days	Wed 1/4/12	Wed 1/4/12	As Soon As Possible	4FF+4 wks
7		Project Full Notice to proceed (NTP)	0 days	Tue 1/10/12	Tue 1/10/12	As Soon As Possible	6FF+4 days
8		**Request for Proposal (RFP) - Engineer/Procure/Co**	**90 days**	**Thu 1/5/12**	**Wed 5/9/12**	**As Soon As Possible**	**6**
9		Prepare	30 days	Thu 1/5/12	Wed 2/15/12	As Soon As Possible	
10		Bid	30 days	Thu 2/16/12	Wed 3/28/12	As Soon As Possible	9
11		Award	30 days	Thu 3/29/12	Wed 5/9/12	As Soon As Possible	10
12		**Power Turbine (PT)**	**80 days**	**Mon 10/8/12**	**Fri 1/25/13**	**As Soon As Possible**	
13		Procure Refurbished Disc and PT Assembly	4 wks	Mon 10/8/12	Fri 11/2/12	As Late As Possible	11
14		Refurbish PT Replacement	5 wks	Mon 11/5/12	Fri 12/7/12	As Late As Possible	13
15		Strip and dissassemble plant	1 wk	Mon 1/7/13	Fri 1/11/13	As Late As Possible	37,11FS+2 wks,16
16		Ship Rotor to Holyrood	5 wks	Mon 12/10/12	Fri 1/11/13	As Soon As Possible	14
17		Rebuild and commission unit	2 wks	Mon 1/14/13	Fri 1/25/13	As Soon As Possible	16,15
18		**Gear Box Overhaul**	**85 days**	**Tue 10/9/12**	**Mon 2/4/13**	**As Soon As Possible**	
19		Strip and dissassemble plant	1 wk	Tue 10/9/12	Mon 10/15/12	As Late As Possible	11FS+4 wks
20		Ship to overhaul plant	5 wks	Tue 10/16/12	Mon 11/19/12	As Late As Possible	19
21		Overhaul and balance Rotor	4 wks	Tue 11/20/12	Mon 12/17/12	As Late As Possible	20
22		Ship to Holyrood	5 wks	Tue 12/18/12	Mon 1/21/13	As Soon As Possible	21
23		Rebuild and commission unit	2 wks	Tue 1/22/13	Mon 2/4/13	As Soon As Possible	22
24		**Avon Gas Generator Overhaul**	**80 days**	**Tue 10/16/12**	**Mon 2/4/13**	**As Soon As Possible**	
25		Procure Refurbished Disc and PT Assembly	4 wks	Tue 10/16/12	Mon 11/12/12	As Late As Possible	11
26		Refurbish PT Replacement	5 wks	Tue 11/13/12	Mon 12/17/12	As Late As Possible	25
27		Strip and dissassemble plant	1 wk	Tue 1/15/13	Mon 1/21/13	As Late As Possible	11FS+2 wks,26FF
28		Ship Rotor to Holyrood	5 wks	Tue 12/18/12	Mon 1/21/13	As Soon As Possible	26
29		Rebuild and commission unit	2 wks	Tue 1/22/13	Mon 2/4/13	As Soon As Possible	28,27
30		**Generator Rewind**	**49 days**	**Wed 11/28/12**	**Mon 2/4/13**	**As Soon As Possible**	
31		Strip and dissassemble plant	2 days	Wed 11/28/12	Thu 11/29/12	As Late As Possible	11FS+2 wks
32		Ship Rotor to overhaul plant	2 wks	Fri 11/30/12	Thu 12/13/12	As Late As Possible	31
33		Overhaul, rewind, and balance Rotor	4 wks	Fri 12/14/12	Thu 1/10/13	As Late As Possible	32
34		Ship Rotor to Holyrood	2 wks	Fri 1/11/13	Thu 1/24/13	As Soon As Possible	33



Project: Project1 Exist Repla GT parts
Date: Mon 8/29/11

Critical	Task	Baseline	Milestone	Project Summary	Deadline
Critical Split	Split	Baseline Split	Summary Progress	External Tasks	
Critical Progress	Task Progress	Baseline Milestone	Summary	External Milestone	

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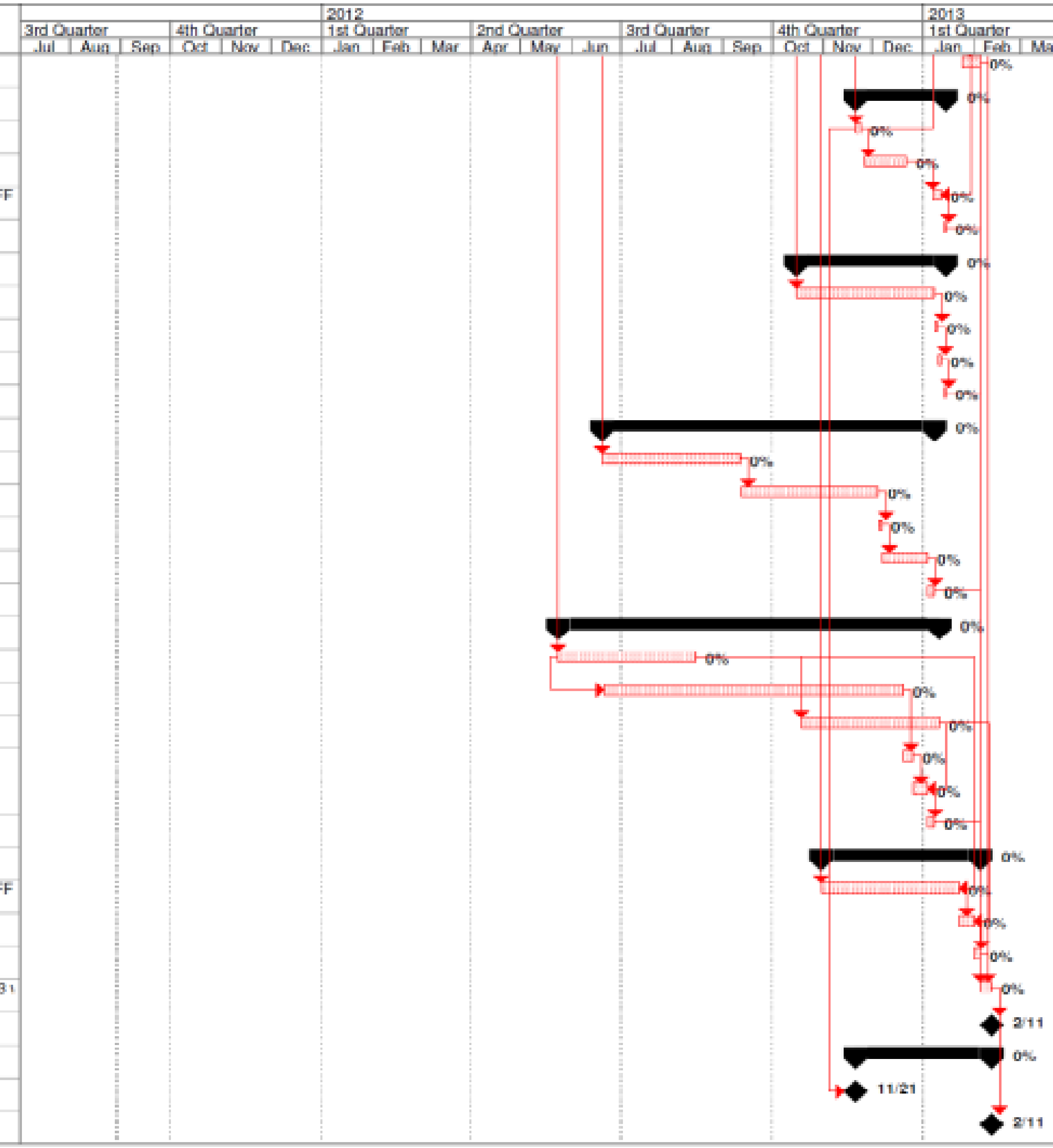
Newfoundland and Labrador Hydro a NALCOR Energy Co.
Holyrood Thermal Generating Station
Gas Turbine Condition Assessment & Options Study

ID		Task Name	Duration	Start	Finish	Constraint Type	Predecessors
35		Rebuild and commission unit	7 days	Fri 1/25/13	Mon 2/4/13	As Soon As Possible	34
36		**Exhaust Stack**	**39 days**	**Wed 11/21/12**	**Mon 1/14/13**	**As Soon As Possible**	
37		Remove	3 days	Wed 11/21/12	Fri 11/23/12	As Late As Possible	11FS+2 wks
38		Repair/Replace	4 wks	Mon 11/26/12	Fri 12/21/12	As Late As Possible	37
39		Re-install	5 days	Mon 1/7/13	Fri 1/11/13	As Late As Possible	38FS+2 wks,17FF
40		Commission unit	1 day	Mon 1/14/13	Mon 1/14/13	As Soon As Possible	39
41		**Intake media**	**65 days**	**Tue 10/16/12**	**Mon 1/14/13**	**As Soon As Possible**	
42		Order & Manufacture Filter media	12 wks	Tue 10/16/12	Mon 1/7/13	As Late As Possible	11FS+2 wks
43		Remove	2 days	Tue 1/8/13	Wed 1/9/13	As Late As Possible	42
44		Repair/Replace	2 days	Thu 1/10/13	Fri 1/11/13	As Late As Possible	43
45		Commission unit	1 day	Mon 1/14/13	Mon 1/14/13	As Soon As Possible	44
46		**Fuel System Refurbishments**	**144 days**	**Wed 6/20/12**	**Mon 1/7/13**	**As Soon As Possible**	
47		Engineer	12 wks	Wed 6/20/12	Tue 9/11/12	As Late As Possible	11FS+2 wks
48		Order, Manufacture, Deliver	12 wks	Wed 9/12/12	Tue 12/4/12	As Late As Possible	47
49		Remove	2 days	Wed 12/5/12	Thu 12/6/12	As Late As Possible	48
50		Repair/Replace	4 wks	Fri 12/7/12	Thu 1/3/13	As Late As Possible	49
51		Commission unit	2 days	Fri 1/4/13	Mon 1/7/13	As Soon As Possible	50
52		**Electrical & Control Systmes**	**166 days**	**Thu 5/24/12**	**Thu 1/10/13**	**As Soon As Possible**	
53		Engineer	12 wks	Thu 5/24/12	Wed 8/15/12	As Late As Possible	11FS+2 wks
54		Order & Manufacture Elect & Control Equip	26 wks	Thu 6/21/12	Wed 12/19/12	As Late As Possible	53SS+4 wks
55		GT Building Addition	12 wks	Fri 10/19/12	Thu 1/10/13	As Late As Possible	53
56		Remove Existing	4 days	Thu 12/20/12	Tue 12/25/12	As Late As Possible	54
57		Install New System	7 days	Wed 12/26/12	Thu 1/3/13	As Late As Possible	56,55FF-1 wk
58		Commission unit	2 days	Fri 1/4/13	Mon 1/7/13	As Soon As Possible	57
59		**Building & Systems**	**69 days**	**Wed 10/31/12**	**Mon 2/4/13**	**As Soon As Possible**	
60		Engineer	12 wks	Wed 10/31/12	Tue 1/22/13	As Late As Possible	11FS+2 wks,53FF
61		Modify and Refurbish	7 days	Wed 1/23/13	Thu 1/31/13	As Late As Possible	60,55FF
62		Commission unit	2 days	Fri 2/1/13	Mon 2/4/13	As Soon As Possible	61
63		Complete Unit Test	5 days	Tue 2/5/13	Mon 2/11/13	As Soon As Possible	29,35,17,40FS+3
64		Gas Turbine (GT) In-service (I/S)	0 days	Mon 2/11/13	Mon 2/11/13	As Soon As Possible	63
65		**UNIT OUTAGE**	**59 days**	**Wed 11/21/12**	**Mon 2/11/13**	**As Soon As Possible**	
66		Unit Outage Start	0 days	Wed 11/21/12	Wed 11/21/12	As Soon As Possible	37SS
67		Unit Outage End	0 days	Mon 2/11/13	Mon 2/11/13	As Soon As Possible	63



Project: Project1 Exist Repla GT parts
Date: Mon 8/29/11

Critical | Task | Baseline | Milestone | Project Summary | Deadline
Critical Split | Split | Baseline Split | Summary Progress | External Tasks
Critical Progress | Task Progress | Baseline Milestone | Summary | External Milestone

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2.9 Annual OMA Cost Estimate to 2020

2.9.1 Historical OMA

Historical operations, maintenance and administration (OMA) data was obtained from the station cost database for the period 2000 to 2011. Information prior to that was not available. Also provided were several recent purchase order invoices from Alba Power for recent boroscope and physical inspections that are assumed to be included in the work order totals, but which may be somewhat out of synchronization. Copies of the "Cost Report by Work Order/Asset" are attached in Appendix 3.

TABLE 2-32 HISTORICAL OMA COST ASSUMPTIONS

OMA

	Maintenance		Fueling	Ops	Total
Year	Work Order k$/Yr OMA	PO Data k$/Yr OMA	k$/Yr Fuel	PO Data k$/Yr OMA	Work Order k$/Yr OMA
2000-2002	$10				
2003	$14		$37	$33	$83
2004	$31		$37	$33	$100
2005	$19		$37	$33	$89
2006	$129	$100	$201	$59	$388
2007	$34	$74	$201	$59	$293
2008	$45	$15	$201	$59	$304
2009	$283	$182	$201	$59	$542
2010	$45	$50	$201	$59	$304
2011	$182		$22	$8	$212
Av/Yr Hist	$68	$84	$126	$44	$257

Most of the historical costs are for relatively minor repairs and do not include major changes such as controls change outs or other major capital modifications. These major costs are not particularly relevant to the OMA analyses going forward.

Several interesting issues arose during the period:

- Ice and snow blockage of parts of lube oil cooler and fuel oil system (led to enclosure of pumps and filters) identified beginning in 2004 and beyond
- GT generator vibration checks (issue) in 2007
- Leak and pressure check on GT gearbox in 2006. Filter not cleaned regularly. Issue in 2003 (last cleaned filter). Fittings change. Gearbox drain valve change -
- Modify/Addition of gear box lube oil vent to relieve pressure in 2007 and 2008
- Lube oil at gearbox cleanup in 2008, 2009, Attempt to fix by Alba 2010; Increase generator end gearbox bearing drain. Fire 2010/2011.
- Several issues in recent years with snow doors operation and rusting, annual checks done
- 2008 lube oil radiator leak

Several major systems had been replaced/modified: controls (twice), gearbox seals, lube oil radiator

2.9.2 Estimated Future OMA

Operating and maintenance (O&M) costs going forward for completely refurbished or new units are not significantly relevant given their level of operation. Most such O&M costs will be for ongoing annual inspection costs. Significant maintenance costs as have been seen recently with the existing unit should not occur if regular inspection and maintenance is undertaken. For completeness, the costs were assumed to include the ongoing maintenance costs (annual inspections, repairs, etc.), the operations costs (costs to run the unit on test), the fuelling costs (fuel costs to run the tests), and an electricity value credit.

The operating costs are shown for both a refurbished case and a non-refurbished case. The assumptions used for fuel, operations, and electricity value are illustrated in Table 2-33. The “electricity value” is a revenue stream premised on recovering fuelling costs plus marginal operating and maintenance costs. The maintenance costs are based on historical maintenance data and information from vendors. The fuelling and electricity prices are intended as representative and based on running the units 150 hours per year, whereas actual hours could be as half of this.. The actual values (average run capacity, sent out heat rate (SOHR) and hence fuel and electricity depend on how the testing is actually done.

TABLE 2-33 EXISTING GTG – FUTURE OMA COST ASSUMPTIONS

Assumptions

		Fuelling
#2 Oil Fuel Price (A)	$/MMBTU	$21.47
Unit Efficiency (B)	BTU/kWh	13,656
Average Running Capacity (C)	MW	4
Average Running Cost (D) = AxBxC/1000	$/Hr	$1,173
Electricity Value (E) = AxB/1000 + $50 Mtce	$/MWh	$343
Electricity Value (F) = E*C	$/Hr OP	$1,373

Operations	
2	Persons/Start (U)
4	Hrs/Start (V)
$70	$/PersonHr (W)
$560	$/Start (Z) = UxVxW

The following OMA costs have been assumed going forward. The non-refurbished case includes an assumption of an equipment failure with modest consequential damage in 2016. “Electricity value” is a revenue stream for electricity sold during testing.

TABLE 2-34 EXISTING GTG – FUTURE OMA COSTS

Existing Unit
1000's Cnd $ - 2011/Yr

	Maintenance		Operations		Fuelling		Sub-Total		Electricity Value		Total	
	With Rehab	Without Rehab	With Rehab	Without Rehab	With Rehab	Without Rehab	With Rehab	Without Rehab	With Rehab	Without Rehab	With Rehab	Without Rehab
2012	$15	$15	$0	$0	$0	$0	$15	$15	$0	$0	$15	$15
2013	$20	$15	$40	$0	$176	$0	$236	$15	($206)	$0	$30	$15
2014	$20	$15	$40	$0	$176	$0	$236	$15	($206)	$0	$30	$15
2015	$20	$15	$40	$0	$176	$0	$236	$15	($206)	$0	$30	$15
2016	$20	$1,500	$40	$1	$176	$88	$236	$1,589	($206)	($103)	$30	$1,486
2017	$20	$15	$40	$0	$176	$0	$236	$15	($206)	$0	$30	$15
2018	$20	$15	$40	$0	$176	$0	$236	$15	($206)	$0	$30	$15
2019	$20	$15	$40	$0	$176	$0	$236	$15	($206)	$0	$30	$15
2020	$0	$0	$40	$0	$176	$0	$216	$0	($206)	$0	$10	$0
TOTAL	$155	$1,605	$323	$1	$1,408	$88	$1,885	$1,694	($1,648)	($103)	$238	$1,591

The actual maintenance costs going forward can be expected to vary widely and could easily be twice those noted, depending on the actual operation of the unit. The costs for operations and for fuel, as well as fuel value are comparable in value or larger.

3 TASK B – REPLACEMENT OPTIONS ASSESSMENT

3.1 Task Details

Mobile/transportable GT and diesel generators were evaluated for their ability to provide Holyrood Thermal Generating Station with black start capability until the year 2020. Following 2020, it is expected the Holyrood plant will no longer be operating as a generating facility**.** The mobile/transportable gas turbine and diesel generators would be available post-2020 for other temporary power uses within NL Hydro's system, and possibly for similar uses prior to 2020 as warranted.

3.2 Assessment Basis

The assessment will be based on an evaluation of Hydro and vendor supplied information regarding the existing Holyrood infrastructure, and new or nearly new transportable power generation units which will either be GT or diesel.

TABLE 3-1 ASSESSMENT CRITERIA

Criteria	Description
Generator	1) Gas Turbine Gen Set 5 MW X 2 – new or nearly new/used 2) Diesel Gen Set 2 MW X5 – new or nearly new/used
Transportability	Transportability - system must be capable of being set up within a week, to ensure that the system can be used elsewhere as needed, particularly after its service has ended at Holyrood. Must comply with local road regulations.
Footprint	Minimize space site requirement of the generator. Set selected must be able to fit on the parking lot adjacent to the emergency response building. This site was selected through discussions with Nalcor personnel.
Electrical output	The system must be able to generate at 13.8 KV, combined system output to be approximately 10 MW peak, with a block load of about 3 to 3.5 MW.
Black Start	Systems must be capable of black start function for the plant and require no more than 600 volt 316 kW for black start
Fuel Type	Must use No. 2 fuel oil
Site Preparation	Unit trailers must be self levelling and require no concrete foundation.
Certification	CSA Certification
Emissions	**Diesel Gensets**: The equipment is assumed to be classified as stationary. The province has jurisdiction, and all existing regulations apply. (In Ontario, the generally accepted practice is that a unit is considered to be stationary if it remains within the same municipal boundaries for 12 continuous months regardless if it's mounted on wheels or not.) Regulations require a dispersion model be prepared to demonstrate compliance with regulations of ground level concentrations of pollutants at the property boundaries or nearest critical receptor. The key parameter is oxides of nitrogen (NOx) and the permitted concentration limit is, for non-emergency generation,

	400 micro-grams per cubic meter of air. The emergency generator limit permitted in NL is not readily identifiable (Ontario NO_x concentration limit for emergency generators is 1880 mg/m3 of air). Newfoundland & Labrador air emissions regulations do require Best Available Control Technology (BACT), but provide for reasonable economics and also for Ministerial exemptions. This would need to be addressed in environmental regulatory approvals. **GT Gensets:** Canadian Council of Ministers of the Environment (CCME) 1992 National Emission Guidelines for Stationary Combustion Turbines may be followed. They do not apply to "Emergency" or "Standby GT" (a unit not normally required for the supply of energy or motive power to meet normal system operational requirements. A "Peaking GT" is a unit ordinarily used to supply electric or motive power in periods of high demand but typically has restricted hours (<3000 hours over 5 years in summer; <7500 hours over 5 years total). The GT Emission Guideline values for diesel fuel are as follows. These units may, however, still have to meet ground level concentration limits, assumed to be 400 ug/m^3 of air, based on dispersion modeling. Peaking Emergency NO_X 530 g/GJ Exempt Notes: g/GJ = grams of NOx as nitrogen dioxide (NO2) per gigajoule (GJ) of net electrical energy output (where 1 megawatthour (MWh) of electricity = 3.6 GJ. AMEC has assessed the diesel emission regulations and considers that the installation would be considered a "stationary source". It is likely to also be considered an emergency unit.

3.3 Options 2 – 2 x 5 MW GT (New, Nearly-New)

3.3.1 Description

In this option, two 5 MW units would be utilized to provide black start capability. Sizing at 5 MW each would allow the units to be more transportable than larger units. Both units would be required to operate simultaneously to provide sufficient power for black start. Vendor information was received from TOROMONT CAT, PETERSON Power Systems CAT, Solar Turbines, and Rolls Royce/Allison Turbine.

These will be mobile units supplied by a vendor and will not require a GT building. Several items will however be required, such as:

- Turbine trailers area with site work to ensure sufficient ground support for the mobile turbines.
- A pre-engineered shelter for electrical equipment, including concrete foundation and floor slab. Approximately 30 ft x 30 ft.
- A reinforced concrete pipe/trench for cables running from the turbines to the main building and from the turbines to the existing fuel lines.
- Electrical and I&C connections to the existing plant facilities

3.3.2 Performance Characteristics

The performance characteristics are based on information from Solar Turbines Taurus 60, (**APPENDIX 4).** Vendors are Peterson, Toromont, and Solar. Peterson also sells used Taurus 60 gen packages.

TABLE 3-2 TURBINE PERFORMANCE CRITERIA

Criteria	Value
KW Gross Output @ ISO Conditions	5,510kW
Voltage	13.8 KV
Site Ambient Temperature for Performance Analysis:	15 C (59 F)
Site Elevation for Performance Analysis:	320 Feet
Site Ambient Relative Humidity for Performance Analysis:	60%
Turbine Inlet Pressure Loss:	4” H20 (inches of water gauge pressure)
Turbine Outlet Pressure Loss:	4”H20
Turbine Fuel Consumption @ specified site conditions (Lower Heating value(LHV)	59 MBTU/hr (Millions of British Thermal Units Per Hour)
KW Gross Output @ specified site conditions:	5,301 kW
Turbine Auxiliary Power Consumption:	15 kW
Net Turbine Power Production	5,286 kW
Black Start kW Requirement (Turbine Generator Set Only)	A 250kW, 480VAC, 3 phase, Black Start Generator is required for turbine starting in the event 13.8kV power is not available.
Fuel Consumption	8.0 gallons per minute (gpm) (30 Liters/min (L/min)). This implies for black start with two units running there would be a total of 16 gpm (60 L/min) and assuming a 24 hour period would require almost 24,000 gallons (90,849 L) of fuel. The current fuel oil tanks as previously noted are 26,417 gallons (100,000 L) each.
Inlet Filter Media	Suitable for Marine Environment

3.3.2.1 Emission Requirements

For a peaking GT unit on oil emission limits would be:

NO_x (Oxides of Nitrogen (NO,NO_2):	530 g (NO_x as NO_2)/ GJ electric energy (1 MWh = 3.6 GJ).
SO_2 (Sulphur dioxide):	970 g SO_2/GJ of electric output. Current 0.2% sulphur (S) in oil (specification) = approximately1572 grams as NO_2/GJ output
CO (Carbon Monoxide):	50 ppm at full load (corrected to 15% O2, dry basis)

Operating time limits could be placed on peaking units. An emergency unit for black start only might be exempt, but could thereby limit its future.

No specific GT applicable Newfoundland air pollution regulations were identified. There is however a general requirement for Best Available Control Technology (BACT), with provisions for an exemption based on economics and on a Ministerial exemption for practical purposes. The typical emission performance for Solar GT units on diesel oil is presented in Table 3-3.

TABLE 3-3 SOLAR GT TYPICAL EMISSIONS

Exhaust Emissions At Stack (Solar)	Measurement	Per Unit
NO_x	parts per million (ppm) @ 15% O2 in flue gas	74
	lb/MMBTU, HHV (Pounds/Million BTU, Higher Heating Value)	0.284
	Pounds/Hour (lb/hr)	17.8
	tons/year	78
CO (Carbon Monoxide)	ppm @ 15% O2	25
	lb/MMBTU, HHV	0.058
	lb/hr	3.7
	tons/year	16
UHC (Unburnt Hydrocarbons	ppm @ 15% O2	25
	lb/MMBTU, HHV	0.033
	lb/hr	2.1
	tons/year	9.2
VOC Volatile Organic Compounds	ppm @ 15% O2	25
	lb/MMBTU, HHV	0.033
	lb/hr	2.1
	tons/year	9.2
$PM_{10}/PM_{2.5}$ (Particulate Matter – Less than 10 and 2.5 microns in size)	lb/hr	2.4
	lb/MMBTU, HHV	0.039
	tons/year	10.7
SO_2	lb/hr	12.91
	lb/MMBTU, HHV	0.20555
	tons/year	56.5
Greenhouse Gas Emissions	lbs of carbon dioxide (CO_2)/MMBTU (HHV)	162

SO_2 emissions depend upon the fuel's sulfur content. The SO_2 estimate is based upon the assumption of 100% conversion of fuel sulphur to SO_2, using assumed values for various fuels that may not reflect actual fuel composition.

3.3.2.2 Transition

The existing GT system is to remain active while new system is independently installed. A short outage will be required during a transition period during which final connections to the electrical, instrumentation and controls, and fuel systems are made.

3.3.2.3 Decommissioning

The existing GT unit will be decommissioned, including those parts of the fuel system and electrical connections not required for the new units. This will occur once the new transportable units are in place and operational. A modified fuel offloading/receiving system will remain.

3.3.3 General Arrangement Sketch

See attached GA sketch based on dimensional information provided by Solar Turbines located in Appendix 4.

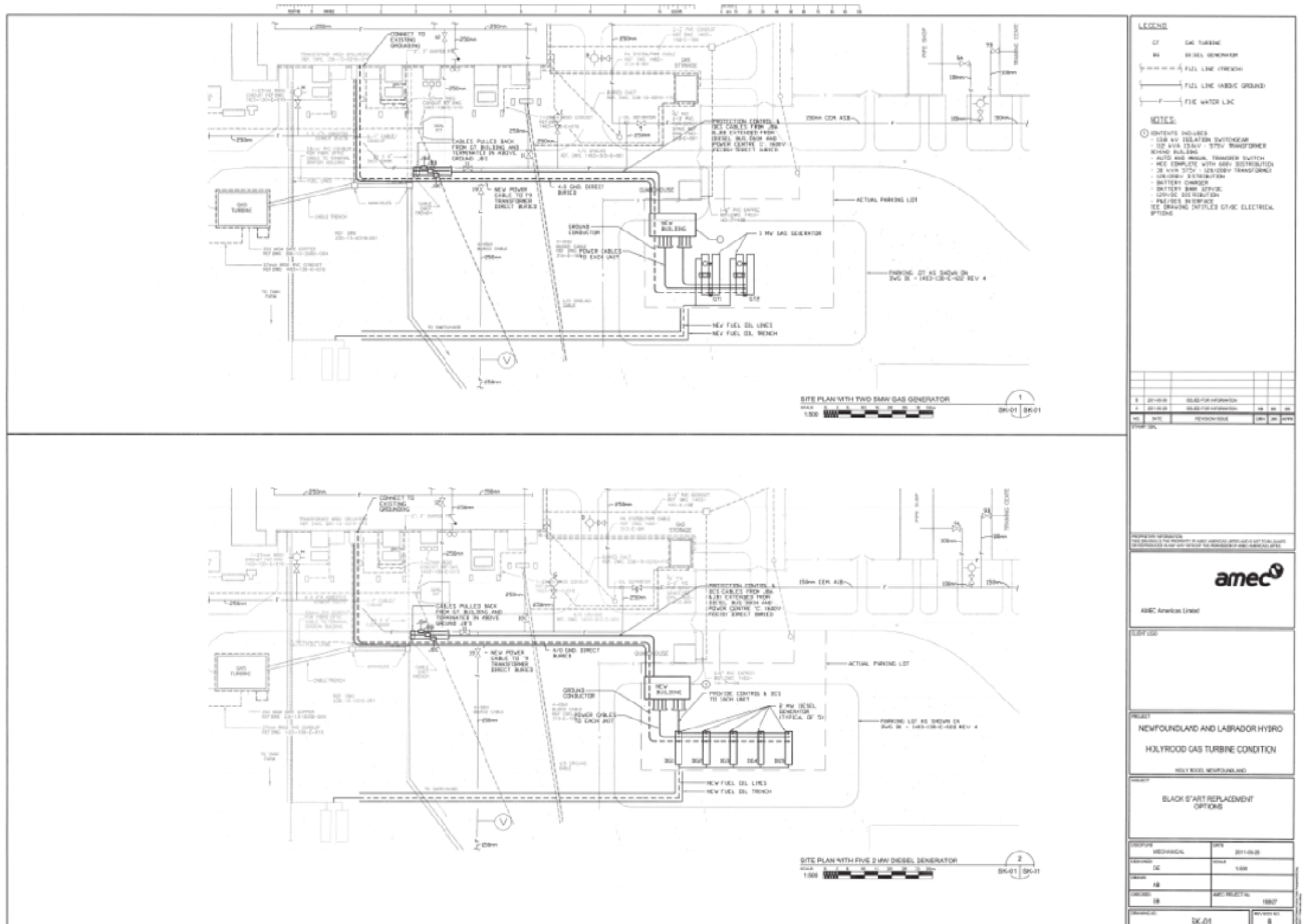


FIGURE 3-1 GENERAL ARRANGEMENT - 2 X 5 MW GAS TURBINE GENERATORS

3.3.4 Capital Cost Estimate

The following estimates are based on budgetary information provided by Solar Turbines (Details in Appendix 4) and Peterson Power Systems (Details in Appendix 5), and Rolls Royce (details in Appendix 6). Following a review of the vendor information, it appears that used units can be available much quicker than a new purchase. The vendors contacted noted that they did not typically have many of these systems available and that they are sold fairly quickly. On Power Inc who use the Rolls Royce 501 turbine noted that they have 4 units being refurbished for sale which may be able to convert to a mobile configuration. The price would be approximately $ 1 M less than a new package.

Note that Peterson Power Systems deals with the rental and sale of used Taurus mobiles whereas Solar Turbines deals with the sale only of new Taurus mobiles. Rolls Royce has indicated that they would require about 1 year for delivery.

There is not expected to be a significant difference in price between the New and Nearly New options, the advantage between these options is the possibility that a Nearly New set of units will be available and lead/delivery times are significantly reduced.

TABLE 3-4 SOLAR TURBINE QUOTE FOR NEW TRANSPORTABLE GTG

Item	Description	Unit Price	Quantity	Cost
1.	Liquid Fuel TAURUS 60-7901S Mobile Power Unit Turbine Generator Set (New) Solar Quote **APPENDIX 4**	$4,535,000.00	2	$9,070,000.00
2.	Commissioning Parts, Start-up, and Site Testing	$70,000	2	$140,000
3	Shipping	$92,100	2	$184,200
4	6% Balance of Plant Contingency	$5,500	2	$11,000
5	Estimation of cost per ISO rating kilowatt for selected equipment	$853		$0
6*	Training*	$9720	1	$29,160
7	Mobile Winterization Package (-40 C)	$219,000	2	$438,000
8	Marine Grade Inlet Air filter	$12,000	2	$24,000
				$9,896,360

- Duties and taxes not included in estimate.
- This quote is provided for budgetary purposes only and does not represent a firm quote.
- Based on Peterson rates.

TABLE 3-5 ROLLS ROYCE QUOTE FOR NEW TRANSPORTABLE GTG

Item	Description	Unit Price	Quantity	Cost
1.	Rolls Royce Allison 501-KB7 mobile GenSet, **APPENDIX 6**	$4,300,000.00	2	$8,600,000.00
2.	Commissioning Parts, Startup, and Site Testing	$70,00.00	2	$140,000.00
3	Shipping	$92,100.00	2	$184,200.00
4	6% Balance of Plant Contingency	$5,500.00	2	$11,000.00
5	Estimation of cost per ISO rating kilowatt for selected equipment	$853.00		$0.00
6	Training	$9720.00	3	$29,160.00
7	Mobile Winterization Package (-40 C)	$219,000.00	2	$438,000.00
8	Marine Grade Inlet Air filter	$12,000.00	2	$24,000.00
				$9,426,360.00

TABLE 3-6 PETERSON QUOTE FOR NEARLY NEW/USED GT'S

Item	Description	Unit Price	Quantity	Cost
1.	Liquid Fuel TAURUS T60 Mobile Power Unit Turbine Generation I Generator Set (Used) Peterson Quote (APPENDIX 5)	$3,800,000.00		$7,600,000
2.	Commissioning Parts, Startup, and Site Testing	$ 63,900.00		$127,800
3	Shipping	$ 92,100.00		$184,200
4	6% Balance of Plant Contingency	$ 5,500.00		$11,000
5	Estimation of cost per ISO rating kilowatt for selected equipment	$ 853.00		$0
6	Training	$ 9,720.00		$29,160
7	Mobile Winterization Package (-40 C)	$ 219,000.00		$438,000
8	Marine Grade Inlet Air filter	$ 12,000.00		$24,000
				$8,414,160

3.3.4.1 Gas Turbine Trailer Units

For consideration under this project, GT packaged trailer systems shall have the following systems and items included with the gas turbine trailer or support trailer. The following is based on information provided by Solar Turbine (Appendix 4).

TABLE 3-7 TRANSPORTABLE GAS TURBINE PACKAGE COMPONENTS

Component	Description
Turbine MODULE:	5.2 MW Output, 13.8 Kilovolts, 60 Hertz, Direct drive starter and lube system, Lube oil cooler, Turbine Weatherproof acoustic enclosure, Power control room weatherproof acoustic enclosure, Fuel oil filter, High Temperature Detection and Alarm, Auxiliary Systems, Lights, On Crank and On Line Water Wash, Ventilation Silencers and Fans, CO2 Fire Suppression System, Fire Detection and Gas Monitoring System, High Efficiency Combustion Air Barrier Filter and Silencer, Trailer mounted exhaust stack and silencer, Control System with local and remote interface and monitoring.
TURBINE TRAILER (Model TK95LCS)	Tri-Axle Transport Trailer with Two Axle Pivoting Booster Length 48' + 14'1" Booster (removable at site) Width 8'6", 9'0" across trailer axles 133" Swing Clearance 49" 5th wheel Height (loaded) Air Ride Suspension and Air Raise and Lowering Kit Steel Disc Wheels with 275/70R x 22.5 Tire Three Tail Light Package Landing Gear (2) 6 Additional Landing Gears with Soil Bearing Plates for Levelling/Stabilization at Site Overall transport height: 14'2" Approximate transport weight: 118,000 lbs (without tractor)
POWER CONTROL MODULE (consists of the following):	Power Control Room (PCR) mounted on Two Axle Transport Trailer, Power Control Room HVAC system, Generator Main Circuit Breaker, Single interface point to power grid, Auxiliary Transformer Feeder Circuit Breaker, Bus PTs, Feeder CTs, Metering CTs and PTs, Beckwith M-3425 Protective Relay Module with the following relays:- Impedance (21), Reverse Power Protection (32), Loss of Field Protection (40), Negative Phase Sequence Protection (46), PT Blown Fuse Protection (60), Time Overcurrent Protection (50/51 V), Neutral Overcurrent Protection (51 N) – utilized in grounded site design, Bus Ground Fault Detection (59N) – utilized in ungrounded site design, Generator Differential Fault Protection (87 G), One High Speed Tripping Relay (86) for Circuit Breaker Trip, Lockout, and Turbine Shutdown Settings, Programming, and Testing, Lightning Arrestor and Surge Capacitor, Motor Control Center. Serves Turbine Generator Auxiliary Loads, 120VDC Turbine Generator Battery System with Charger, Dedicated 120VDC Switchgear Battery System with Charger, Start Motor Variable Frequency Drive (VFD), DC Backup Lube Oil Pump Contactor, Interior Lighting, Photocell Controlled Exterior Lighting at Access Doors, Emergency Eyewash Station, Ancillary Equipment. Installed onto the Power Control Room Module are the following: Gas Turbine Lube Oil Cooler, Neutral Ground Resistor, Auxiliary Load Transformer
Power Control Room Trailer (Model TK70LCS)	Two Axle Transport Trailer, Trailer Length 46' Overall, Width 8'6", 49" 5th wheel Height (loaded), Air Ride Suspension and Air Raise and Lower Kit, Steel Disc Wheels with 255/70R x 22.5 Tires, Three Tail Light Package, Landing Gear, 4 Additional Landing Gears with Soil Bearing Plates for Levelling/Stabilization at Site, Overall Transport Height: 14'0", Approximate transport weight: 48,000 lbs. (without tractor)

3.3.4.2 Site Civil Works

Site/civil works requirements are primarily related to the gas turbine generator trailer site, and to electrical and fuel connections. The major costs are expected to be:

- Confirming the bearing capacity of soil = $4,000
- Pre-engineered shelter for elec. equipment = $45,000
- Concrete cable trench = $70,000

Oil piping excavation is included in the cost of the piping.

3.3.4.3 Gas Turbine Generator Unit Modifications

For this application, the gas turbine units should be provided with air filter media suitable for use in a marine environment as well as have coatings on external components designed for such environments.

3.3.4.4 New Gas Turbine Generator Mechanical Requirements

Aside from fuel oil supply, it is expected that the gas turbine units would be self contained and not require any additional mechanical equipment. If required for the water wash system, a water line would be provided.

Connection and Changes to Existing Oil System

From supplier information, each turbine at its maximum output would consume fuel at a rate of about 8.0 gpm (30 L/min). This implies for black start with two units running there would be a total of 16 gpm (60 L/min). For a 24 hour period, the fuel oil storage requirement would be about 24,000 gallons (90,849 L) of fuel. The current Fuel oil tanks as previously noted are 26,417 gal (100,000 L) each.

The fuel requirement makes portable tanks impractical for the 8 year solution and this will also have to be considered in the gas turbine transportability consideration. The new gas turbine units will be located approximately 160 m from the existing GT building and will require new fuel oil supply and return piping from the existing system. Since two gas turbines would be provided under this option it is anticipated that only two line connections would be required. Piping could be routed through a trenched containment system.

TABLE 3-8 NEW GTG – MECHANICAL SYSTEM COSTS

Item	Cost
3" supply and return fuel line	$77,100.00
Project Engineering Costs Mechanical	$17,000.00

3.3.5 New Gas Turbine Option – Electrical, Instrumentation, and Control Requirements

Option 1 is 2 x 5 MW gas turbine generators rated at 13.8 kV. This option involves the replacement of the existing GTG with two (2) GT units rated at 5 MW. Each has a generator output voltage of 13.8kV and is connected to the delta primary of the existing T9 transformer.

3.3.5.1.1 Connections to the Existing Electrical and Control System

Each GT unit will be a completely self contained capable of operating in 'isochronous' or 'droop' mode, having its own main breaker (52), AVR, control and protection, synchronizing, load sharing, paralleling, monitoring and ability to connect to the existing station DCS.

All these functions will connect to a new building. Each generator breaker will be cabled to an item of isolating switchgear. The isolating switchgear will consist of two (2) 13.8kV disconnect switches, one (1) fused disconnect for auxiliaries, and one disconnect for connection of the zig-zag grounding transformer.

An isolation switch allows the individual GT unit to be taken out of service at any time. Each generator breaker (52) is synchronized for connection to the station service bus through the 13.8kV:4160V transformer T9, either individually or as a pair of generators.

The two GT units will be designed with high resistance grounding consisting of a grounding transformer and NGR to limit the ground fault current to less than 10A as normal standard.

The governor and voltage regulation control of the two units is common in utilities. Another advantage is the reliability of the emergency supply source and it is felt the probability of successful starts of one of the two units is better than one GT. For essential auxiliaries loads it requires only one unit running to secure the station during total loss of AC power (black-out).

The 13.8kV fused disconnect FSWI will feed a 112 kVA, 13.8 kV:575 V, 3 phase transformer to provide 600 V service via a new 600 A, 600 V, 3 phase, 60 Hz, 3 W MCC. The MCC will typically provide starters or fused disconnects for pumps, heating, 120/208 V distribution via a 30 kVA transformer and the battery charger. The battery charger supplies the 129 VDC battery and distribution.

Alternative supplies to the MCC will be via an automatic transfer switch (ATS) and a manual transfer switch (MTS), and will be from the diesel bus DB34 and power centre 'C', both in the powerhouse.

Protection and Control/DCS (P&C/DCS) interfaces will combine the requirements of the new units with the requirements of the existing T9 transformer and 4160V breaker SSB2.

3.3.5.1.2 Changes to existing El and C System

The existing protection, control and DCS cables entering the present GT building will be pulled back and terminated in a weatherproof Junction Box (JB). New teck cables will be connected to these existing cables and direct-buried from the JB to the P&C/DCS interface in the new building.

Similarly, the 600 V feeds from the diesel bus DB34 and power centre 'C' will be pulled-back and terminated in weatherproof JB's. New teck cables will be connected to these existing cables and direct-buried from the JB's to the manual transfer switch (MTS) in the new 'building'.

All new weatherproof JB's will be mounted above ground.

Power cables from the common bus of the isolating switchgear to the existing T9 transformer will replace the existing cables, and will be direct-buried from T9 transformer to the switchgear.

Changes will be made as necessary to the P&C located in Panel 13 (in the powerhouse) and also in Panel 2 (in the powerhouse). Screens will be reconfigured in the control room involving the two new units and their monitoring, control, indication, and alarm functions.

Each unit will be capable of operating in parallel when connected to an isolated 4160 V bus through a transformer (T9 Step-down), i.e. isochronous mode load sharing.

Each unit will be capable of energizing step-down transformer T9 to pick-up essential loads on the 4160 V bus.

The two unit operation will be controlled through a master controller to direct which unit is to pick-up dead-bus, and which unit is to synchronize with the other unit.

The start/stop commands are given from the master controller for auto-operation or manually from the control room.

Voltage Drop on the 4160 V Bus

The voltage drop on the 4160 V bus during starting the largest MV motor - 3000 horsepower (hp) boiler feed pump (BFP) motor under the condition of both 5 MW units running (in islanded mode) is about 10% below the recommended minimum of 80% by NEMA MGI. At the same time, starting of a 3000 hp BFP with isolation transformer was found to be unacceptable following preliminary simulation calculations from ETAP. Therefore a detailed procedure must be prepared for the black-start of MV motors.

3.3.5.2 4160 V Generator Voltage Option

The 2 x 5 MW generators with outputs at 4160 V are no longer considered for the following reasons:

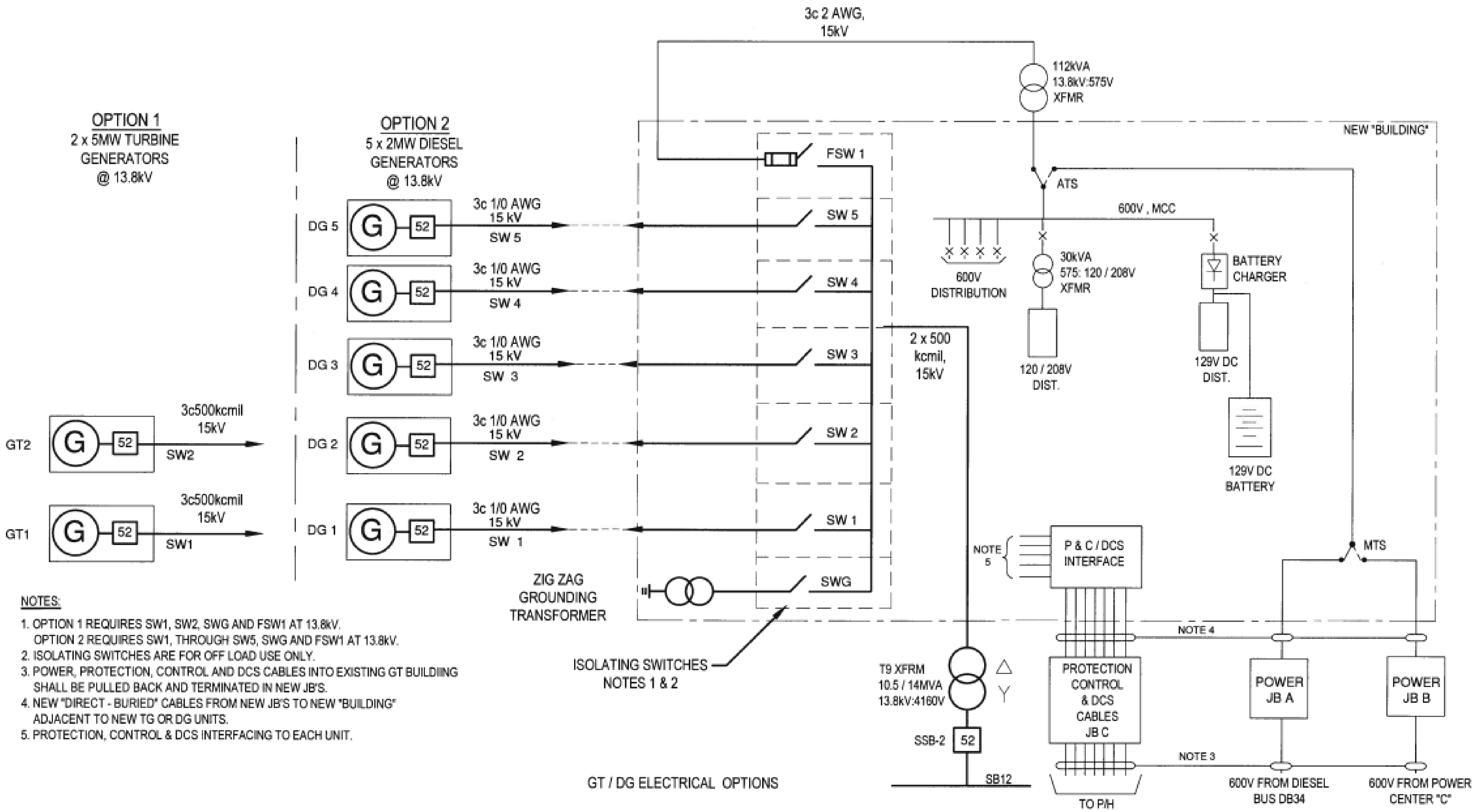
1. The 4160 V generator characteristics are not suitable for large motor starting, even without the step-down transformer.

2. The distance between the generators and the 4160 V bus is long (+200 M), therefore the voltage drop will be more, which results in costly power cables.

3. The existing ground fault current of the 4160 V bus is 1000 A, therefore the generators must have the generator neutral current of 1000 A. With low grounding resistance there is the possibility of third harmonic current circulating from one generator to another. The 4160 V diesel gensets submitted by the vendor cannot be connected to 4160 V because of them being unable to withstand the 1000 A ground fault on the 4160 V bus.

4. With generator connected directly to the 4160 V bus which is normally fed from the grid, three-phase short circuit current contribution from the grid (to the internal fault near the line end of the generator winding), is significant which results in more damage to the generator windings.

In conclusion, this option is not preferred compared to the other option of 2 x 5 MW units.



NOTES:

1. OPTION 1 REQUIRES SW1, SW2, SWG AND FSW1 AT 13.8kV.
   OPTION 2 REQUIRES SW1, THROUGH SW5, SWG AND FSW1 AT 13.8kV.
2. ISOLATING SWITCHES ARE FOR OFF LOAD USE ONLY.
3. POWER, PROTECTION, CONTROL AND DCS CABLES INTO EXISTING GT BUILDIING SHALL BE PULLED BACK AND TERMINATED IN NEW JB'S.
4. NEW "DIRECT - BURIED" CABLES FROM NEW JB'S TO NEW "BUILDING" ADJACENT TO NEW TG OR DG UNITS.
5. PROTECTION, CONTROL & DCS INTERFACING TO EACH UNIT.

FIGURE 3-2 SINGLE LINE SKETCH – NEW GAS TURBINE GENSET

TABLE 3-9 ELECTRICAL & CONTROL EQUIPMENT AND INSTALLATION COSTS (OPTION 1) 2 X 5MW TG'S

Item #	Desciption	Qty	Unit	Material	Labour	Total	Comments
1	3c500 kemil, Teck 15kV cable (2 runs)	550	m	112,750	10000	122,750	Power from T9 to switchgear and to generators
2	13.8kV isolating switchgear (3+1 fused switch)	1	ea	95,000	10,000	105,000	
3	P&C/DCS interface	1	ea	55,000	10,000	65,000	Will contain interfacing requirements of the new units to T9 and SSB2.
4	10 x 3c12AWG, Teck, 1000V cable	250	m	960	2250	3210	from P&C/DCS interface to GTI and GT2 for protection and control
5	2 x 25c16AWG, Teck, 1000V cable	350	m	8505	3150	11655	Cables from P&C/DCS interface to junction box JBC
	4 x 4c12AWG, Teck, 1000V cable	700	m	3290	6300	9590	Cable from FSWI to 112kV transformer
	1 x 12C12AWG, Teck, 1000V cable	175	m	2240	1575	3815	Cable ATS to MTS and JBA/JBB to MTS
6	3c2AWG, Teck, 15kV cable	15	m	945	250	1195	
7	2 x 3c1/0, Teck, 1000V cable	125	m	4500	1125	5625	
8	112kVA, 13.8kV:575V, 3ph, 60Hz transformer	1	ea	30000	3000	33000	
9	200A, 600V, 3ph, 60Hz automatic transfer switch	1	ea	5336	1500	6836	
10	200A, 600V, 3ph, 60Hz manual transfer switch	1	ea	2000	1000	3000	
11	MCC, 600A, 600V, 3ph, 3W	1	ea	30000	5000	35000	
12	30kVA, 575:120/280V, 3ph, 60Hz transformer	1	ea	1000	500	1500	
13	129VDC distribution panel, motor starters and disconnects	1	ea	35000	6500	41500	
14	100A, 120/208V, 3ph, 60Hz distribution panel c/w breakers	1	ea	1418	350	1768	
15	600V, battery charger, 129VDC output	1	ea	16,000	3220	19,220	
16	129VDC battery bank	1	ea	39,000	7500	46,500	
17	All interconnecting cabling	1	lot	16000	12000	28000	Includes MCC feeders, heating and lighting
18	Miscellaneous 4/0 ground wire, conducts trays and hardware	1	lot	16000	9000	25000	
19	Reconfiguration of DCS screens, and existing system	1	lot		25,000	25000	
20	25kVA, 13.8kV, 3ph, 60Hz, zig-zag grounding transformer	1	ea	31,000	2,000	33,000	
	Commissioning			-	63,000	63,000	
	Totals			505,944	184220	690,164	

3.3.6 Existing Unit De-Commissioning and Demolition

No significant incremental costs were identified for existing unit de-commissioning and/or demolition. It was felt that the value of the materials derived from the demolition could offset the cost to the contractor. If required as sensitivity, then a value such as $40,000 might be used, but this would not be expected to either sway the selection of a preferred option, or impact the overall cost but rather be part of an overall project contingency regardless of any option selected.

3.3.7 Project Engineering and Management, Owner's Costs

It was assumed that the facility implementation would be undertaken largely as an engineer, procure, construct (EPC) external contract. Hydro would be responsible for getting the project approved and the necessary environmental and regulatory approvals.

EPC Costs

For the EPC contractor, the project engineering and management costs are based on the total project costs and a percentage for engineering and for management. For the purposes of this estimate, the engineering costs are estimated to be 5% of direct costs of the GT or diesel package and 10% of the balance of plant. The project management and commissioning costs (excluding fuel, Hydro staff costs) are estimated to be 7% of total direct costs. .

Owner's Costs

Owner's costs are not included in the estimates, but are likely to be comparable regardless of the selected option. NL Hydro is assumed to undertake the early steps to get its Public Utilities Board (PUB) approvals as part of its ongoing operations cost. Hydro is also assumed to undertake all the necessary environmental and regulatory permitting entirely internally or with some measure of external support (i.e. environmental modeling and engineering support, or full external scope). This cost is also not included but likely on the order of $55,000.

For the actual project implementation, the assumption is that NL Hydro would assume its own costs of this initial development and then assign a project manager for the life of the project to monitor and assure its successful completion. These and other NL Hydro costs (insurance, legal, supply chain, interest, owners' contingency, Holyrood station participation, commissioning fuel, commissioning labour) are not identified or included herein. It is likely that Owner costs could amount to on the order of 1.5% of directs or about $150,000.

3.3.8 Total New and Nearly New 2 x 5MW GTG Capital Cost Estimate

The total New and Nearly New 2 x 5 MW GTG cost estimate is as follows. The difference in the New and Nearly New is mostly in the capital costs. It should be noted that there may be some additional costs required to retrofit nearly new units to meet the same or required standards as the new units that are designed to meet Holyrood requirements.

TABLE 3-10 CAPITAL COST ESTIMATE – TRANSPORTABLE GTG

Capital Cost Comparison
Capital cost estimate $1,000 Can 2011

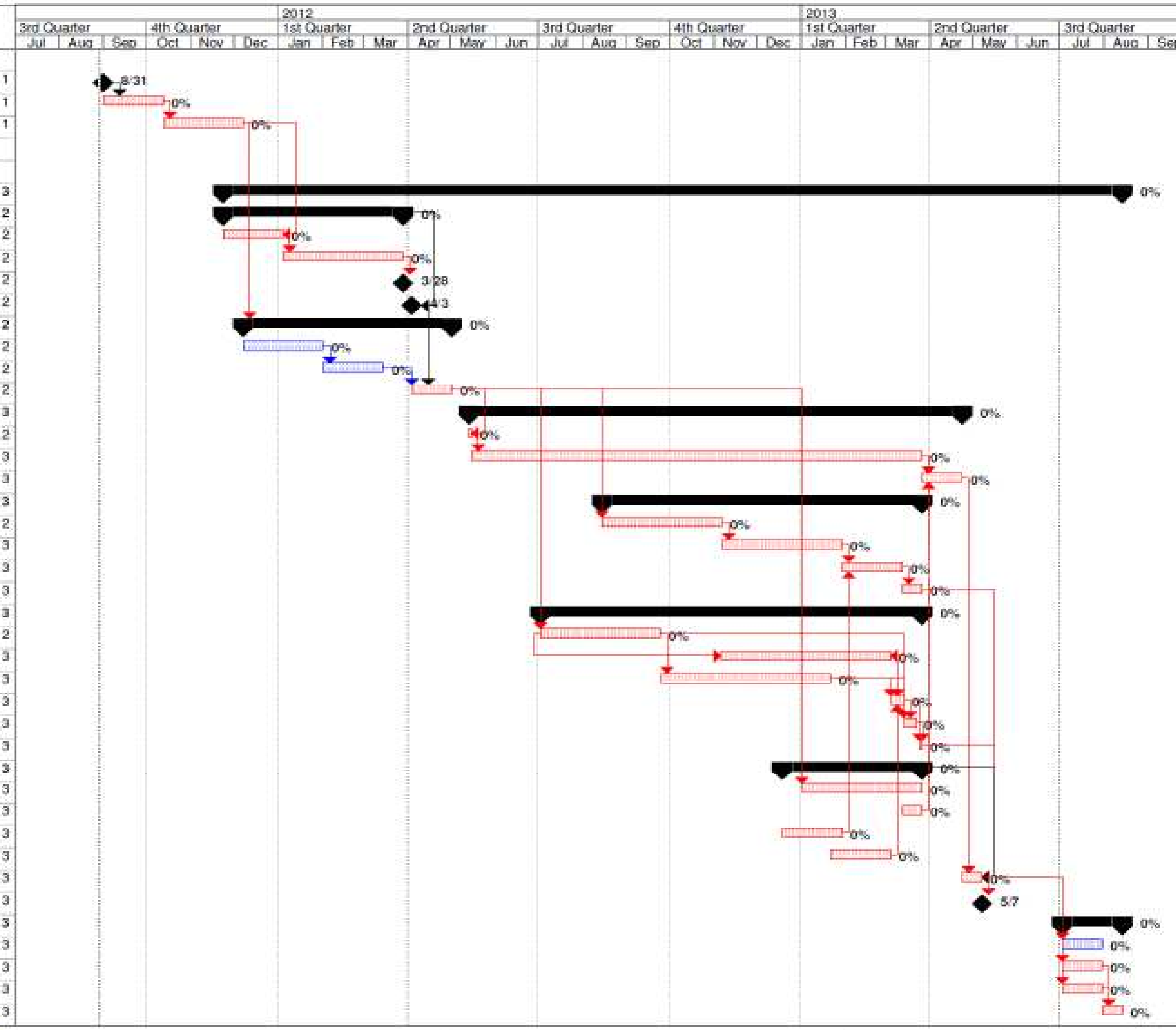
Option Number	1	1A
Option	**New 2 x 5 MW GT**	**Used 2 x 5 MW GT**
GT/Diesel Cost	$10,865	$9,234
Civil Works	$131	$131
Electrical Works	$759	$759
BOP Systems	$129	$129
Existing Unit Demolition & Removal	$7	$7
Sub-Total - Directs and Indirects	$11,891	$10,260
Project Engineering	$625	$544
Project Management	$832	$718
Total	$13,348	$11,522

3.3.9 Schedule

The schedules for the new and nearly new 2 X 5 MW GTG are illustrated below. The basic schedule highlights are as follows:

Task	New GT	Nearly New GT
Review of Options Report	Sept 2011	
Project Approvals and Release	Sept 2011 - Dec 2011	
Engineer, Procure, Construct Contract	May 2012	
In-Service of New 2 x 5 MW GT	May 2013	March 2013
Decommission Existing GT	Aug/Dec 2013	Aug/Dec 2013

ID	Task Name	Duration	Start	Finish
1				
2	Condition Assessment Study	0 wks	Wed 8/31/11	Wed 8/31/11
3	Hydro Internal Capital Budget Proposal Development	6 wks	Thu 9/1/11	Wed 10/12/11
4	Submission - Public Utilities Board & Approval	8 wks	Thu 10/13/11	Wed 12/7/11
5				
6				
7	**New GT or Diesel Units**	**449 days**	**Thu 11/24/11**	**Tue 8/13/13**
8	**Project Environmental & Regulatory Approvals**	**90 days**	**Thu 11/24/11**	**Wed 3/28/12**
9	Prepare Dispersion Modelling & Submission	30 days	Thu 11/24/11	Wed 1/4/12
10	Regulatory Review and Approval	60 days	Thu 1/5/12	Wed 3/28/12
11	Environmental Approval	0 days	Wed 3/28/12	Wed 3/28/12
12	Project Full Release	0 days	Tue 4/3/12	Tue 4/3/12
13	**Request for Proposal (RFP) for Engineer/procure/Cons**	**104 days**	**Thu 12/8/11**	**Tue 5/1/12**
14	Prepare	40 days	Thu 12/8/11	Wed 2/1/12
15	Bid	6 wks	Thu 2/2/12	Wed 3/14/12
16	Award	20 days	Wed 4/4/12	Tue 5/1/12
17	**New Gas Turbien or Diesel Engine Generator**	**247 days**	**Mon 5/14/12**	**Tue 4/23/13**
18	Award Gas Turbine (GT)/Engine Contract	2 days	Mon 5/14/12	Tue 5/15/12
19	Manufacture & Deliver Transportable Engines	45 wks	Wed 5/16/12	Tue 3/26/13
20	Install and Commission	4 wks	Wed 3/27/13	Tue 4/23/13
21	**Fuel System**	**160 days**	**Wed 8/15/12**	**Tue 3/26/13**
22	Engineer	12 wks	Wed 8/15/12	Tue 11/6/12
23	Order, Manufacture, Deliver	12 wks	Wed 11/7/12	Tue 1/29/13
24	Install new fuel lines and receiving system	6 wks	Wed 1/30/13	Tue 3/12/13
25	Commission System	2 wks	Wed 3/13/13	Tue 3/26/13
26	**Electrical & Control Systmes**	**191 days**	**Tue 7/3/12**	**Tue 3/26/13**
27	Engineer	12 wks	Tue 7/3/12	Mon 9/24/12
28	Order & Manufacture Elect & Control (E&C) Equip	17 wks	Tue 11/6/12	Mon 3/4/13
29	Electrical Building Manufacture, Delivery, Install	17 wks	Tue 9/25/12	Mon 1/21/13
30	Install New System	7 days	Tue 3/5/13	Wed 3/13/13
31	RE-align Existing Plant Systems	7 days	Thu 3/14/13	Fri 3/22/13
32	Commission unit	2 days	Mon 3/25/13	Tue 3/26/13
33	**Site Civil Work**	**70 days**	**Wed 12/19/12**	**Tue 3/26/13**
34	Engineer	12 wks	Wed 1/2/13	Tue 3/26/13
35	Generator area clearing and civil	2 wks	Wed 3/13/13	Tue 3/26/13
36	Fuel line civil work	6 wks	Wed 12/19/12	Tue 1/29/13
37	Electrical an contro cable civil work	6 wks	Tue 1/22/13	Mon 3/4/13
38	Complete Unit Test	10 days	Wed 4/24/13	Tue 5/7/13
39	Gas Turbine (GT) In-Service (I/S)	0 days	Tue 5/7/13	Tue 5/7/13
40	**Decommission Existing GT**	**30 days**	**Wed 7/3/13**	**Tue 8/13/13**
41	Fuel delivery system	4 wks	Wed 7/3/13	Tue 7/30/13
42	Electrical & Controls	4 wks	Wed 7/3/13	Tue 7/30/13
43	GT	4 wks	Wed 7/3/13	Tue 7/30/13
44	Building	2 wks	Wed 7/31/13	Tue 8/13/13



Project: Project1 New.mpp
Date: Mon 8/29/11

Critical	Task	Baseline	Milestone	Project Summary
Critical Split	Split	Baseline Split	Summary Progress	External Tasks
Critical Progress	Task Progress	Baseline Milestone	Summary	External Milestone
				Deadline

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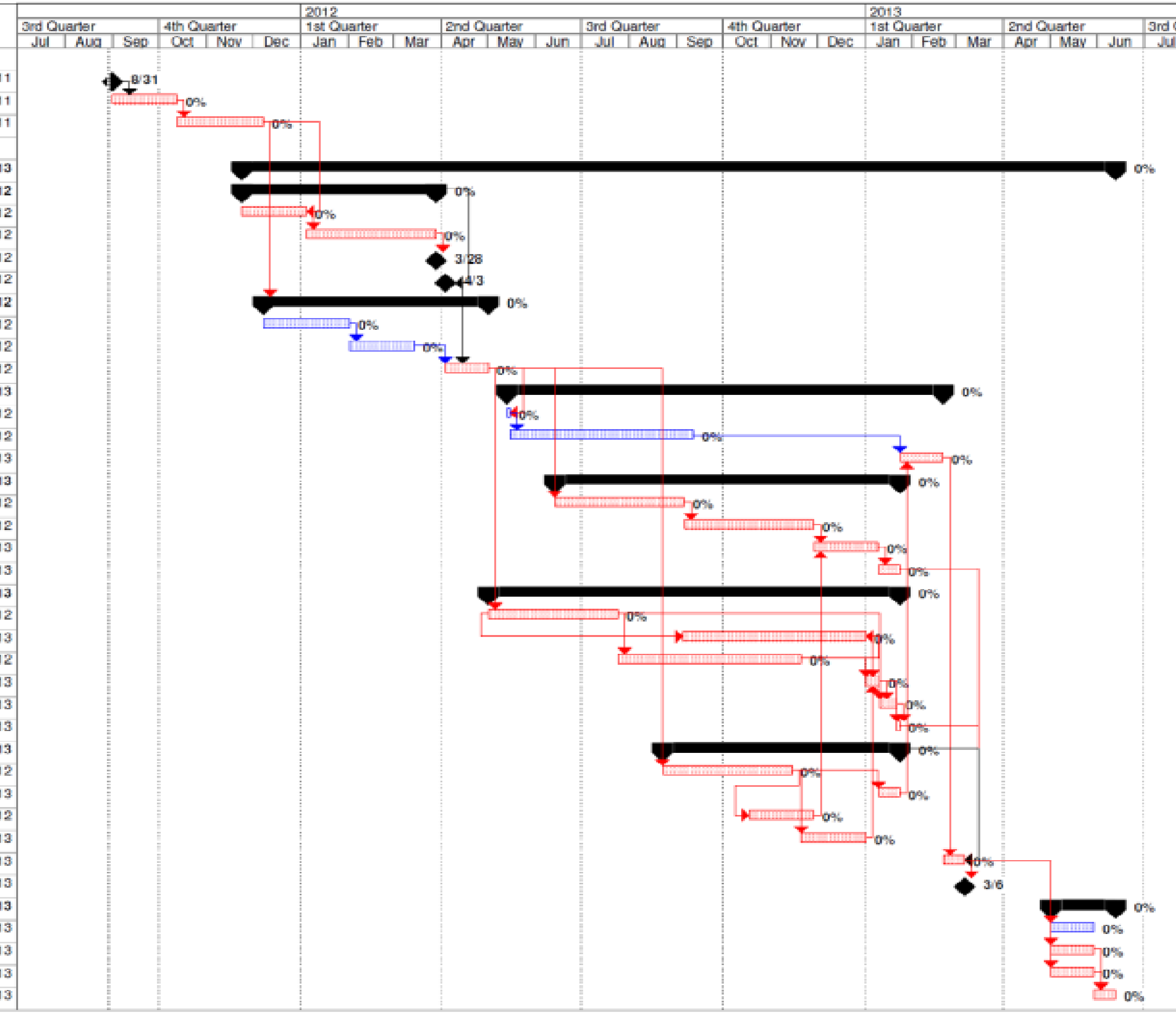
FIGURE 3-3 SCHEDULE – NEW TRANSPORTABLE 2 X 5 MW GTG

ID	Task Name	Duration	Start	Finish
1				
2	Condition Assessment Study	0 wks	Wed 8/31/11	Wed 8/31/11
3	Hydro Internal Capital Budget Proposal Development	6 wks	Thu 9/1/11	Wed 10/12/11
4	Submission - Public Utilities Board & Approval	8 wks	Thu 10/13/11	Wed 12/7/11
5				
6	**Nearly New gas Turbine (GT) or Diesel Generator Units**	**405 days**	**Thu 11/24/11**	**Wed 6/12/13**
7	**Project Environmental & Regulatory Approvals**	**90 days**	**Thu 11/24/11**	**Wed 3/28/12**
8	Prepare Dispersion Modelling & Submission	30 days	Thu 11/24/11	Wed 1/4/12
9	Regulatory Review and Approval	60 days	Thu 1/5/12	Wed 3/28/12
10	Environmental Approval	0 days	Wed 3/28/12	Wed 3/28/12
11	Project Full Release	0 days	Tue 4/3/12	Tue 4/3/12
12	**Request for Proposal (RFP) for Engineer/Procure/Construct (**	**104 days**	**Thu 12/8/11**	**Tue 5/1/12**
13	Prepare	40 days	Thu 12/8/11	Wed 2/1/12
14	Bid	6 wks	Thu 2/2/12	Wed 3/14/12
15	Award	20 days	Wed 4/4/12	Tue 5/1/12
16	**Nearly New GT or Diesel Engine Generator**	**203 days**	**Mon 5/14/12**	**Wed 2/20/13**
17	Award GT/Diesel Engine Contract	2 days	Mon 5/14/12	Tue 5/15/12
18	Manufacture & Deliver Transportable Engines	17 wks	Wed 5/16/12	Tue 9/11/12
19	Install and Commission	4 wks	Thu 1/24/13	Wed 2/20/13
20	**Fuel System**	**160 days**	**Thu 6/14/12**	**Wed 1/23/13**
21	Engineer	12 wks	Thu 6/14/12	Wed 9/5/12
22	Order, Manufacture, Deliver	12 wks	Thu 9/6/12	Wed 11/28/12
23	Install new fuel lines and receiving system	6 wks	Thu 11/29/12	Wed 1/9/13
24	Commission System	2 wks	Thu 1/10/13	Wed 1/23/13
25	**Electrical & Control Systmes**	**191 days**	**Wed 5/2/12**	**Wed 1/23/13**
26	Engineer	12 wks	Wed 5/2/12	Tue 7/24/12
27	Order & Manufacture Elect & Control (E&C) Equip	17 wks	Wed 9/5/12	Tue 1/1/13
28	Electrical Building Manufacture, Delivery, Install	17 wks	Wed 7/25/12	Tue 11/20/12
29	Install New System	7 days	Wed 1/2/13	Thu 1/10/13
30	RE-align Existing Plant Systems	7 days	Fri 1/11/13	Mon 1/21/13
31	Commission unit	2 days	Tue 1/22/13	Wed 1/23/13
32	**Site Civil Work**	**110 days**	**Thu 8/23/12**	**Wed 1/23/13**
33	Engineer	12 wks	Thu 8/23/12	Wed 11/14/12
34	Generator area clearing and civil	2 wks	Thu 1/10/13	Wed 1/23/13
35	Fuel line civil work	6 wks	Thu 10/18/12	Wed 11/28/12
36	Electrical an contro cable civil work	6 wks	Wed 11/21/12	Tue 1/1/13
37	Complete Unit Test	10 days	Thu 2/21/13	Wed 3/6/13
38	GT In-Service (I/S)	0 days	Wed 3/6/13	Wed 3/6/13
39	**Decommission Existing GT**	**30 days**	**Thu 5/2/13**	**Wed 6/12/13**
40	Fuel delivery system	4 wks	Thu 5/2/13	Wed 5/29/13
41	Electrical & Controls	4 wks	Thu 5/2/13	Wed 5/29/13
42	GT	4 wks	Thu 5/2/13	Wed 5/29/13
43	Building	2 wks	Thu 5/30/13	Wed 6/12/13



Project: Project1 Nearly New.mpp
Date: Mon 8/29/11

Critical		Task		Baseline		Milestone		Project Summary		Deadline	
Critical Split		Split		Baseline Split		Summary Progress		External Tasks			
Critical Progress		Task Progress		Baseline Milestone		Summary		External Milestone			

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FIGURE 3-4 SCHEDULE – NEARLY NEW/USED TRANSPORTABLE 2 X 5 MW GTG

3.3.10 OMA Cost Estimate to 2020

Operating costs were assumed to include the ongoing maintenance costs (annual inspections, repairs, etc.), the operations costs (costs to run the unit on test), the fuelling costs (fuel costs to run the tests), and an electricity value credit. The operating costs shown are the same for both the new and nearly new cases. For the type of operation required, peak and emergency operation (typically <=60 Hrs/Yr, the GT packages normally would require only an annual service and inspection by qualified service personnel. Most utilities would exercise the equipment once a month to verify proper operation.

The costs were assumed to include the ongoing maintenance costs (annual inspections, repairs, etc.), the operations costs (costs to run the unit on test), the fuelling costs (fuel costs to run the tests), and an electricity value credit. The vendor indicated that for the 6 month inspection the cost was to be $10,000 and for the yearly it was $18,000 and that these costs would be the same for both new and nearly new. A lower value was actually used reflecting their very limited use – essentially an annual inspection similar to what is done now.

The assumptions used for fuel, operations, and electricity value are illustrated below. The electricity value is premised on receiving the same value per MWh as the existing units would if they were to recover their fuelling costs plus marginal operating and maintenance costs. The fuelling and electricity prices are intended as representative and based on running the units 150 hours per year, whereas actual hours could be as half of this.. The actual values (average run capacity, sent out heat rate (SOHR) and hence fuel and electricity depend on how the testing is actually done.

The assumptions used for fuel, operations, and electricity value are illustrated below. The electricity value is premised on recovering fuelling costs plus marginal operating costs.

TABLE 3-11 NEW GTG OMA COST ASSUMPTIONS

Assumptions

#2 Oil Fuel Price (A)	$/MMBTU	$21.47
Unit Efficiency (B)	BTU/kWh	12,000
Average Running Capacity (C)	MW	4
Average Running Cost (D) = AxBxC/1000	$/Hr	$1,031
Electricity Value (E) = Value for existing GT	$/MWh	$343.25
Electricity Value (F) = E*C	$/Hr OP	$1,373

2	Persons/Start (U)
4	Hrs/Start (V)
$70	$/PersonHr (W)
$560	$/Start (Z) = UxVxW

TABLE 3-12 NEW GTG OMA COSTS

New/Near New GT
1000's Cnd $ - 2011/Yr

	Maintenance	Operations	Fuelling	Sub-Total	Electricity Value		Total
2012	$15	$0	$0	$15	$0		$15
2013	$20	$40	$155	$215	($206)		$9
2014	$20	$40	$155	$215	($206)		$9
2015	$20	$40	$155	$215	($206)		$9
2016	$20	$40	$155	$215	($206)		$9
2017	$20	$40	$155	$215	($206)		$9
2018	$20	$40	$155	$215	($206)		$9
2019	$20	$40	$155	$215	($206)		$9
2020	$0	$40	$155	$195	($206)		($11)
TOTAL	$155	$323	$1,237	$1,714	($1,648)		$67

3.4 Option 2 – 5 x 2 MW Diesel Engine Generator (DG) at 13.8kV (New and Nearly New Option)

3.4.1 Description

In this option, five 2 MW diesel engine generator units would be utilized to provide black start capability. Sizing at 2 MW each would allow the units to be more transportable than larger units. In addition, this is approximately the maximum size available for portable units. With this arrangement, all five of the units would be required to operate simultaneously to provide sufficient power for black start. A generator voltage of 13.8 kV connected to the delta primary of the existing T9 transformer would be utilized. Other units from Cummins Diesel are available as packaged two 1 MW units. However, NL Hydro expressed reliability and operational concerns with 10 diesel units and they have not been considered further.

Vendor information was received from TOROMONT CAT. These will be mobile units supplied by a vendor and will not require a diesel building. Several items will however be required, such as:

- Turbine trailers areas with site work to ensure sufficient ground support for the mobile diesel genset units.
- A pre-engineered shelter for electrical equipment, including concrete foundation and floor slab. Approximately 30 ft x 30 ft.
- A reinforced concrete pipe/trench for cables running from the diesel gensets to the main building and from the diesel gensets to the existing fuel lines.
- Electrical and I&C connections to the existing plant facilities

3.4.2 Connections to the Existing E and C System

Each diesel/generator unit will be a completely self contained unit capable of operating in isochronous or droop mode, having its own main breaker (52), AVR, control and protection, synchronizing, load sharing, paralleling, monitoring and ability to connect to the existing station DCS.

All these functions will connect to a new building. Each generator output breaker will be cabled to an item of isolating switchgear. The isolating switchgear will consist of five (5) 13.8 kV disconnect switches, one (1) fused disconnect for auxiliaries, and one disconnect for connection of the zig-zag grounding transformer.

An isolation switch allows the individual GT unit to be taken out of service at any time. Each generator breaker (52) is synchronized for connection to the station service bus through the 13.8 kV:4160 V transformer (T9), either individually or as any combination of generators.

The five DG units will be designed with high resistance grounding consisting of a grounding transformer and NGR to limit the ground fault current to less than 10 A as normal standard.

The 13.8KV fused disconnect fused switch #1 (FSWI) will feed a 112 kVA, 13.8 kV:575 V, 3 phase transformer to provide 600 V service via a new 600 A, 600 V, 3phase, 60 Hz, 3 W MCC. The MCC will typically provide starters or fused disconnects for pumps, hearing, 120/208 V distribution via a 30 kVA transformer and the battery charger. The battery charger supplies the 129 VDC battery and distribution.

Alternative supplies to the MCC will be via an automatic transfer switch (ATS) and a manual transfer switch (MTS) and will be from the diesel bus DB34 and power center ‘C’, both located in the powerhouse.

Protection & Control/DCS interfaces will combine the requirements of the new units with the requirements of the existing T9 transformer and 4160 V breaker SSB2.

3.4.2.1.1 Changes to Existing EI&C Systems

The existing protection, control and DCS cables entering the present GT building will be pulled-back and terminated in a weatherproof JB. New teck cables will be connected to these existing cables and direct-buried from the JB to the P&C/DCS interface in the new building.

Similarly the 600 V feeds from the diesel bus DB34 and power centre ‘C’ will be pulled-back and terminated in weatherproof JB’s. New teck cables will be connected to these existing cables and direct-buried from the JB’s to the MTS in the new ‘building’.

All new weatherproof JB’s will be mounted above ground.

Power cable from the common bus of the isolating switchgear to the existing T9 transformer will replace the existing cables, and will be direct-buried from T9 to the switchgear.

Changes will be made as necessary to P&C in Panel 13 (in the powerhouse) and also in Panel 2 (in the powerhouse). Screens will be reconfigured in the control room involving the five new units and their monitoring, control, indication, and alarm functions.

3.4.3 Performance Characteristics

Diesel gensets have several ratings.

> Standby – Applicable for supplying continuous electrical power (at variable load) in the event of a utility power failure. No overload is permitted on these ratings. The generator on the generator set is peak prime rated (as defined in ISO8528-3) at 30°C (86°F).
>
> Prime – Applicable for supplying continuous electrical power (at variable load) in lieu of commercially purchased power. There is no limitation to the annual hours of operation and the generator set can supply 10% overload power for 1 hour in 12 hours.

NL Hydro noted that for blackstart only, their requirement is for the standby rating. Information on prime is provided for comparison.

TABLE 3-13 DIESEL PERFORMANCE CRITERIA

Generator Set Technical Data	Units	60 Hz Prime	60 Hz Standby
Performance Specification		DM8264	DM8264
Power Rating	kW (kVA)	1825 (2281)	2000 (2500)
Lubricating System Oil pan capacity	L (gal)	401.3 (106)	401.3 (106)
Fuel System Fuel Consumption 100% load 75 % load 50 %load Fuel tank capacity Running time @ 75% rating	L (gal) L (gal) L (gal) L (gal) Hours	483.2 (127.6) 380 (100.4) 270.5 (71.5) 4731 (1,250) 12.5	525.7 (138.9 408.2 (107.8) 294.2 (77.7) 4731 (1,250) 11.5
Cooling System Radiator coolant capacity including engine	L (gal)	630 (166)	630 (166)
Air Requirements Combustion air flow Maximum air cleaner restriction Generator cooling air	m3/min (cfm) kPa (in H2O) m3/min (cfm)	174.7 (6169) 6.2 (24.9) 168 (4,995)	180.3 (6367) 6.2 (24.9) 168 (4,995)
Exhaust System Exhaust flow at rated kW Exhaust stack temperature at rated kW dry exhaust	m3/min (cfm) °C (°F)	404 (14,260) 387 (728)	428.6 (15,137) 405 (762)
Noise Rating (with enclosure) @ 7 meters (23 feet) @15 meters (50 feet)	dB(A) dB(A)	78 74	79 75

3.4.3.1 Emission Requirements

For new diesel units on oil, the requirement is uncertain. In the United States, the United States Environmental protection Agency (USEPA) is clearly moving to even tighter diesel genset limits. Canada has only adopted those for mobile (on-road) sources, not stationary sources. There is also the issue of emergency use (black-start would apply) and non-emergency (distribution support, grid support is likely to apply):

- For stationary (including transportable genset units) in emergency use (i.e. black start only)
  - In US would likely be a USEPA Tier 2 (a diesel requiring advanced combustion systems)
  - In Canada, no specific regulations could be identified. Diesel units are likely similar to those required in the US, or comparable to the Canadian guideline requirement for gas turbines above

- For stationary (including transportable genset) in a non-emergency use (i.e. distribution support).
  - In the US, a USEPA Tier 4 (a diesel unit required to have advanced combustion and post combustion control such as selective catalytic reduction (SCR) using ammonia or urea and would also require ultralow sulphur diesel fuel (15 ppm sulphur)
  - In Canada, no specific regulations identified – the study assumes for the role required that Tier 2 would suffice. A question may arise where the plan is for their use in distribution system support. This should likely be considered an emergency role and not result in more onerous restrictions. At worst, assuming a requirement comparable to that for gas turbines above for peaking purposes is reasonable.

Operating time limits could be placed on peaking units. An emergency unit for black start only might be exempt, but could thereby limit its future.

No specific diesel genset applicable to Newfoundland air pollution regulations were identified. There is however a general requirement for BACT, with provisions for an exemption based on economics and on a ministerial exemption for practical purposes.

In emergency and non-emergency applications, dispersion modeling is likely required to demonstrate ground level concentrations are acceptable.

3.4.3.2 Transition

The existing gas turbine system is to remain active while the new system is independently installed. A short outage will be required during a transition period during which final connections to the electrical, instrumentation and controls, and fuel systems are made.

3.4.3.3 Decommissioning

The existing GT unit will be decommissioned, including those parts of the fuel system and electrical connections not required for the new units. This will occur once the new transportable units are in place and operational. A modified fuel offloading/receiving system will remain.

3.4.4 General Arrangement Sketch

See attached GA sketch based on dimensional information provided by TOROMONT CAT (APPENDIX 3).

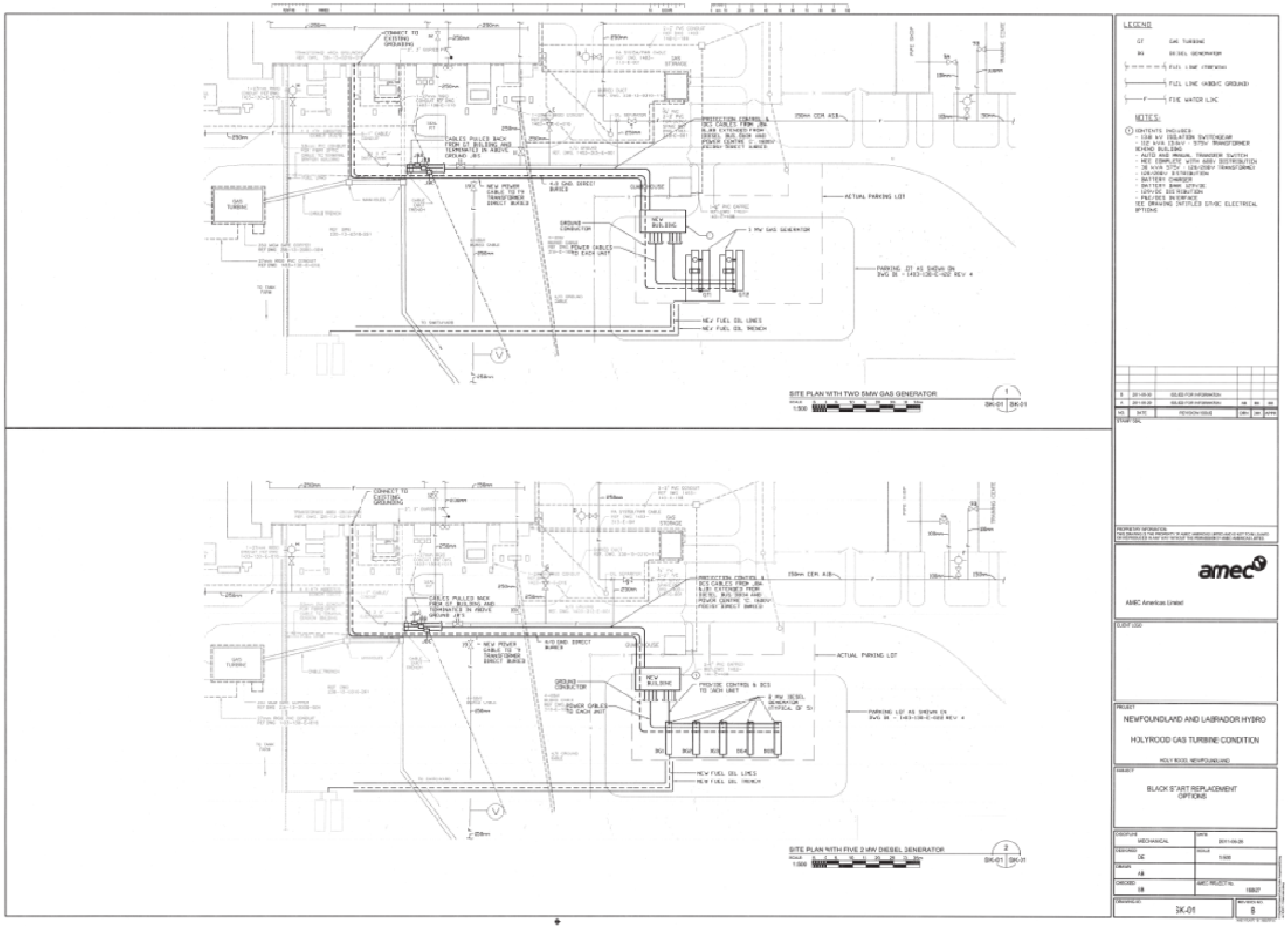


FIGURE 3-5 GENERAL ARRANGEMENT – 5 X 2 MW DIESEL GENSETS

3.4.5 Capital Cost Estimate (Differentiate New and Nearly New Option)

Budget pricing supplied by CAT indicated that the transportable diesel genset cost would be in the order of $1,500,000.00 per unit. However, there could be a 50% increase in price if the units are required to meet more stringent emission limits in emission regulations likely to be adopted soon by the federal government. AMEC has requested this information but as not received any additional details on these requirements, and their applicability to this application for black start capability and short term distribution system maintenance support.

There is not expected to be a significant difference in price between the New and Nearly New options. The advantage between these options is the possibility that a Nearly New set of units will be available and lead/delivery times are significantly reduced.

TABLE 3-14 DIESEL GENSET CAPITAL COST

Item	Description	Unit Price	Quantity	Cost
1.	XQ2000 with 13.8kv output $1.5m per unit (x5) under current emissions rules.	$1,500,000	5	$7,500,000
2.	Commissioning Parts, Start-up, and Site Testing	$20,000	5	$100,000
4	Shipping	$25,000	5	$125,000
5	Training	$5,000	5	$25,000
6	Marine Grade Filter (Included)			
				$7,750,000

- Duties and taxes not included in estimate.
- This quote is provided for budgetary purposes only and does not represent a firm quote.

3.4.5.1 Diesel Trailer Units

TABLE 3-15 DIESEL PACKAGE COMPONENTS

Component	Description
Engine	▪ EPA approved Tier 2 3516C Caterpillar engine ▪ Heavy duty air cleaner with service indicator ▪ 60-Amp charging alternator ▪ Fuel filters – primary and duplex secondary with integral water separator and change-over valve ▪ Lubricating oil system with spin-on, full flow oil filters and water cooled oil cooler ▪ Oil drain lines routed to engine rail ▪ Jacket water heater ▪ Fuel cooler and priming pump ▪ Electronic ADEM™ A3 controls ▪ 24V electric starting motors with battery rack and cables

Component	Description
	▪ 110% spill containment of onboard engine fluids
Generator	▪ SR-4B brushless, permanent magnet excited, three-phase with Caterpillar digital voltage regulator (CDVR),space heater, 6-lead design, Class H insulation operating at Class F temperature for extended life, ▪ winding temperature detectors and anti-condensation space heaters (120/240 V 1.2 kW)
Containerized Module	▪ 40' ISO high cube container, CSC certified ▪ 3-axle, 40' ISO container chassis ▪ Seven (7) sound attenuated air intake louvers and 4 lockable personnel doors with panic release ▪ Side bus bar access door, external access load connection bus bars ▪ Shore power connection via distribution block connections for jacket water heater, battery charger, space heaters, and generator condensate heaters ▪ Standard lighting 3 AC/4 DC, one (1) single duplex service receptacle, 2 external break-glass emergency stop push buttons ▪ 1,250 gal fuel tank, UL listed, double wall, 9 hr runtime @ prime rating ▪ Sound attenuated 75 dB(A) @ 50 ft ▪ Spill containment 110% of all engine fluids ▪ Four (4) oversized maintenance-free batteries, battery rack and 20-Amp battery charger ▪ Hospital grade, internally insulated, rectangular exhaust silencer with vertical discharge ▪ Vibration isolators, corrosion resistant hardware and hinges ▪ External drain access to standard fluids ▪ Fire extinguishers (Qty 2) ▪ Standard Cat rental decals and painted standard Cat power module white ▪ Interior walls and ceilings insulated with 100 mm of acoustic paneling ▪ Floor of container insulated with acoustic glass and covered with galvanized steel
Cooling	▪ Standard cooling provides 43° C ambient capability (60 Hz) at prime +10% rating ▪ Vertically mounted, separate ATAAC and JW cores with vertical air discharge

Component	Description
Generator Paralleling Control	▪ Custom switchgear control with EMCP 3.3 genset mounted controller and wall mounted paralleling controls Provides single unit and/or multi-unit/utility paralleling components. Standby, load sense/load demand, import, export, and base load modes. Comes standard with Basler Utility Multi-function Relay IPS-100. ▪ Exclusive Caterpillar Digital Voltage Regulator (CDVR) Three-phase sensing and adjustable Volts-per- Hertz regulation give precise control, excellent block loading, and constant voltage in the normal operating range. ▪ Automatic start/stop with cool down timer ▪ Protections: 25, 27/59, 40, 32, 81 O/U ▪ Utility multi-function relay protections: 25,27/59, 32, 47, 50/51, 62, 67, 81 O/U ▪ UMR is IEEE1547-2003 compliant in most applications ▪ Reverse compatibility module provided for interface to legacy power modules ▪ Touch screen controls with event log ▪ Multi-mode operation (island, multi-island and utility parallel), load sharing (multi-unit only) ▪ Import & export control (utility parallel only), manual and automatic paralleling capability ▪ Touch screen display (status and alarms) ▪ Metering display: voltage, current, frequency, power factor, kW, WHM, kVAR, and synchroscope
Quality	▪ Standard genset and package factory tested ▪ UL, NEMA, ISO and IEEE standards
Other	

3.4.5.2 Site Civil Works – Trailer Site and Electrical & Gas Connections

Site/civil works requirements are primarily related to the diesel generator trailer site, and to electrical and fuel connections. The major costs are expected to be:

- Confirming the bearing capacity of soil = $4,000
- Pre-engineered shelter for elec. equipment = $45,000
- Concrete cable trench = $70,000

Oil piping excavation is included in the cost of the piping.

3.4.5.3 Existing Gas Turbine Generator Unit Modifications

For this application the gas turbine units should be provided with air filter media suitable for use in a marine environment as well as have coatings on external components designed for such environments.

3.4.5.4 New Diesel Genset Mechanical Requirements

Aside from fuel oil supply, it is expected that the diesel genset units would be self contained and not require any additional mechanical equipment. Specific to diesel engine trailers, each trailer must have 15.6 m clearance on both sides to ensure adequate ventilation and combustion airflow.

Connection to Fuel Oil System and Changes to Existing Oil System

From supplier information each turbine at its maximum output would consume fuel at a rate of 2.3 gpm (8.7 L/min). This implies for black start with five units running there would be a total of 11.5 gpm (43.5 L/min). For a 24 hour period, the fuel oil storage requirement would be about 16,500 gallons (62, 459 L) of fuel. The current fuel oil tanks as previously noted are 26,417 gal (100,000 L) each.

The new diesel units will be located approximately 160 m away from the existing GT building and will require new fuel oil supply and return piping from the existing system. Since five diesels would be provided under this option, it is anticipated that five connections would be required. Due to spacing requirements of the diesels gen sets this manifold system would be quite extensive. Piping could be routed through a trenched containment system. Preliminary sizing indicates that the supply and return lines would be 3 inch with a total length of 130 m each.

TABLE 3-16 DIESEL GENSET – MECHANICAL SYSTEM COSTS

Item	Cost
3” supply and return fuel line	$77,100.00
Project Engineering Costs Mechanical	$15,000.00

3.4.6 New Diesel Genset Option – Electrical, Instrumentation, and Control Requirements

With generators connected directly to the 4160 V bus which is normally fed from the grid, the three-phase short circuit current contribution from the grid (to the internal fault near the line end of the generator winding) is significant which results in more damage to the generator windings.

With the 5 X 2 MW generators, the calculated voltage drop at the 4160 V bus results are improved, but potential drawbacks are expected as follows:

1. The starting reliability of 5 generators (following total loss of station AC supply) is questionable. The successful starting of 5 units is not easy to achieve. With our experience of multiple diesel starting at once, there is a high probability that 100% success is not easily achieved compared to two 5 MW units on the assumption that one 5 MW unit is suitable for plant essential loads.

2. The isochronous load sharing of 5 units requires 5 electronic governors and a complicated master controller. This is necessary to manage the paralleling operation of 5 units during isochronous mode, particularly during starting of MV motors. This will cost more.

3. With the same contribution of fault current from the grid through the l0 MVA step-down transformer, may exceed the damaging level of the 2 MW generator for internal fault of the stator (close to line end of windings).

4. The 13.8 kV switchgear line-up would be much larger than the 2 X 5 MW option.

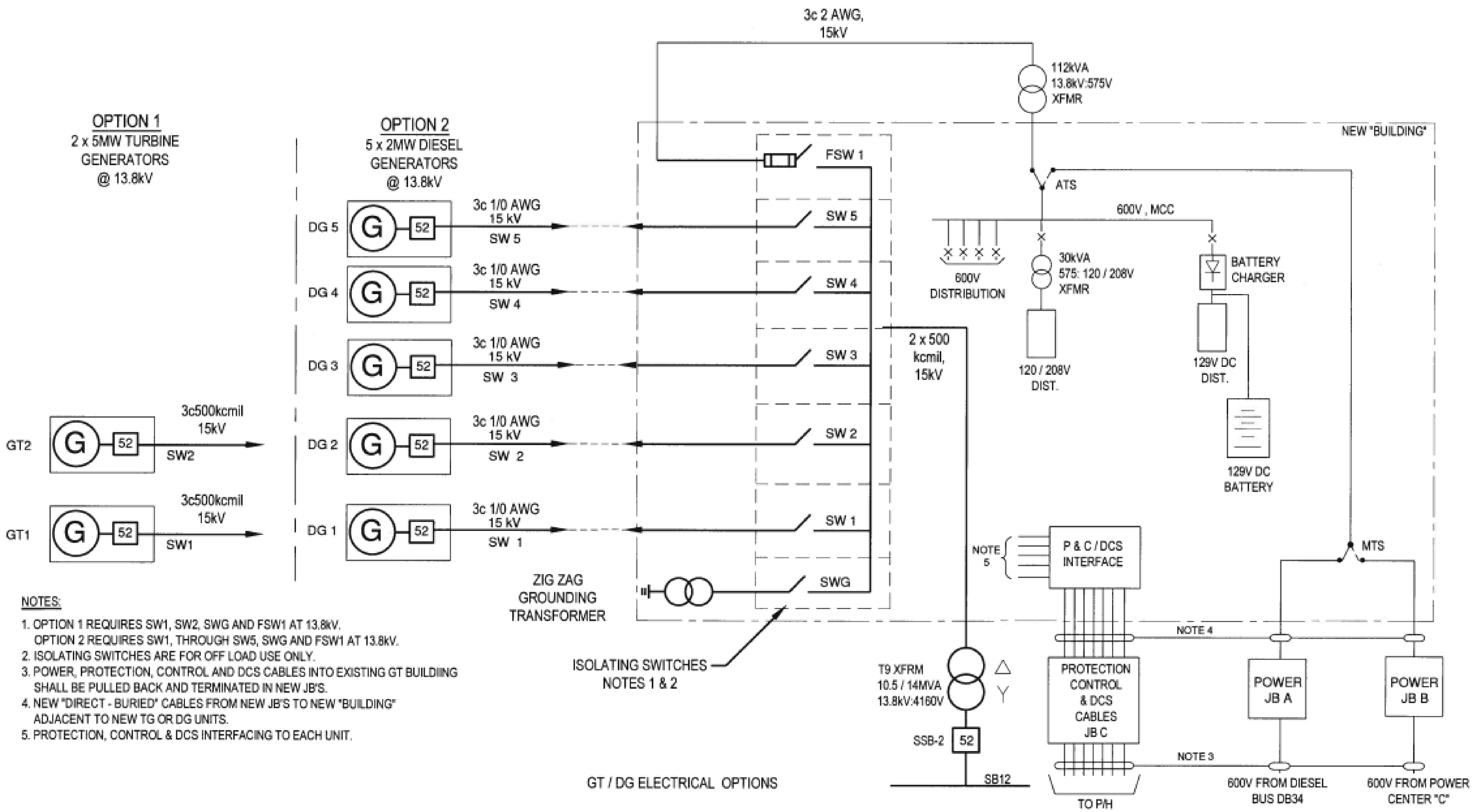


FIGURE 3-6 SINGLE LINE SKETCH – NEW DIESEL GENSET

3.4.6.1 Equipment & Installation Costs – Electrical & Controls

TABLE 3-17 ELECTRICAL & CONTROL EQUIPMENT AND INSTALLATION COSTS (OPTION 2) – 5 X 2 MW TGS @ 4160 V.

Item #	Desciption	Qty	Unit	Material	Labour	Total	Comments
1	3c500 kemil, Teck 15kV cable (2 runs)	440	m	90,200	10,000	100,200	Power from switchgear to generators T9 and grounding transformer
2	3C 1/0 AWG Teck 15kV cable	300	M	10,800	4,000	14,800	
3	13.8kV isolating switchgear (6+1 fused switch)	1	ea	144700	15000	159,700	
4	P&C/DCS interface	1	ea	65,000	10,000	75,000	Will contain interfacing requirements of the new units to T9 and SSB2
5	10 x 3c12AWG, Teck, 1000V cable	500	m	1920	4500	6420	from P&C/DCS interface to DG1 through DG5 for protection and control
6	2 x 24c16AWG, Teck, 1000V cable	350	m	8505	3150	11,655	Cables from P&C/DCS interface to junction box JBC
7	4 x 4c12AWG, Teck, 1000V cable	700	m	3290	6300	9590	Cable from FSWI to 112kV transformer
8	1 x 12C12AWG, Teck, 1000V cable	175	m	2240	1575	3815	Cable ATS to MTS and JBA/JBB to MTS
9	3c2AWG, Teck, 15kV cable	15	m	945	135	1080	
10	2 x 3c1/0, Teck, 1000V cable	125	m	4500	1125	5625	
11	112kVA, 13.8kV:575V, 3ph, 60Hz transformer	1	ea	30000	3000	33000	
12	200A, 600V, 3ph, 60Hz automatic transfer switch	1	ea	5336	1500	6836	
13	200A, 600V, 3ph, 60Hz manual transfer switch	1	ea	2000	1000	3000	
14	MCC, 600A, 600V, 3ph, 3W	1	ea	30000	5000	35000	
15	30kVA, 575:120/280V, 3ph, 60Hz transformer	1	ea	1,000	500	1,500	
16	129VDC distribution panel, motor starters and disconnects	1	ea	35000	6500	41500	
17	100A, 120/208V, 3ph, 60Hz distribution panel c/w breakers	1	ea	1418	350	1768	
18	600V, battery charger, 129VDC output	1	ea	16,000	3220	19,220	
19	129VDC battery bank	1	ea	39,000	7500	46,500	
20	All interconnecting cabling	1	lot	16000	12000	28000	Includes MCC feeders, heating and lighting
21	Miscellaneous 4/0 ground wire, tray and hardware	1	lot	16000	9000	25,000	
22	Reconfiguration of DCS screens, and existing system	1	lot	-	25,000	25,000	
23	25 kVA, 13.8kV, 3ph, 60Hz, zig-zag grounding transformer	1	ea	31,000	2,000	33,000	
24	Commissioning			-	69,000	69,000	
	Totals			554,854	201,355	756,209	

3.4.7 Existing Unit De-Commissioning and Demolition

No significant incremental costs were identified for existing unit de-commissioning and/or demolition. It was felt that the value of the materials derived from the demolition could offset the cost to the contractor. If required as a sensitivity, then a value such as $40,000 might be used. This would not be expected to either sway the selection of a preferred option or impact the overall cost. It should be considered as part of an overall project contingency regardless of any option selected.

3.4.8 Project Engineering and Management, Owner's Costs

It was assumed that the facility implementation would be undertaken largely as an engineer, procure, construct (EPC) external contract. NL Hydro would be responsible for getting the project approved and the necessary environmental and regulatory approvals.

EPC Costs

For the EPC contractor, the project engineering and management costs are based on the total project costs and a percentage for engineering and for management. For the purposes of this estimate, the engineering costs are estimated to be 5% of direct costs of the GT or diesel package and 10% of the balance of plant. The project management and commissioning costs (excluding fuel, Hydro staff costs) are estimated to be 7% of total direct costs. .

Owner's Costs

Owner's costs are not included in the estimates, but are likely to be comparable regardless of the selected option. NL Hydro is also assumed to undertake all the necessary environmental and regulatory permitting entirely internally or with some measure of external support (i.e. environmental modeling and engineering support, or full external scope). This cost is also not included but likely on the order of $55,000.

For the actual project implementation, the assumption is that NL Hydro would assume its own costs of this initial development and then assign a project manager for the life of the project to monitor and assure its successful completion. These and other NL Hydro costs (insurance, legal, supply chain, interest, owners' contingency, Holyrood station participation, commissioning fuel, commissioning labour) are not identified or included herein. It is likely that Owner costs could amount to on the order of 1.5% of directs or about $150,000.

3.4.9 Total New and Nearly New 5 x 2MW Diesel Generator Capital Cost Estimate

The total New and Nearly New 5 x 2 MW diesel generator cost estimate is as follows. The difference in the New and Nearly New is mostly in the capital costs. It should be noted that there may be some additional costs required to retrofit nearly new units to meet the same or required standards as the new units that are designed to meet Holyrood requirements.

TABLE 3-18 CAPITAL COST ESTIMATE – TRANSPORTABLE DIESEL GENSET

Capital Cost Comparison
Capital cost estimate $1,000 Can 2011

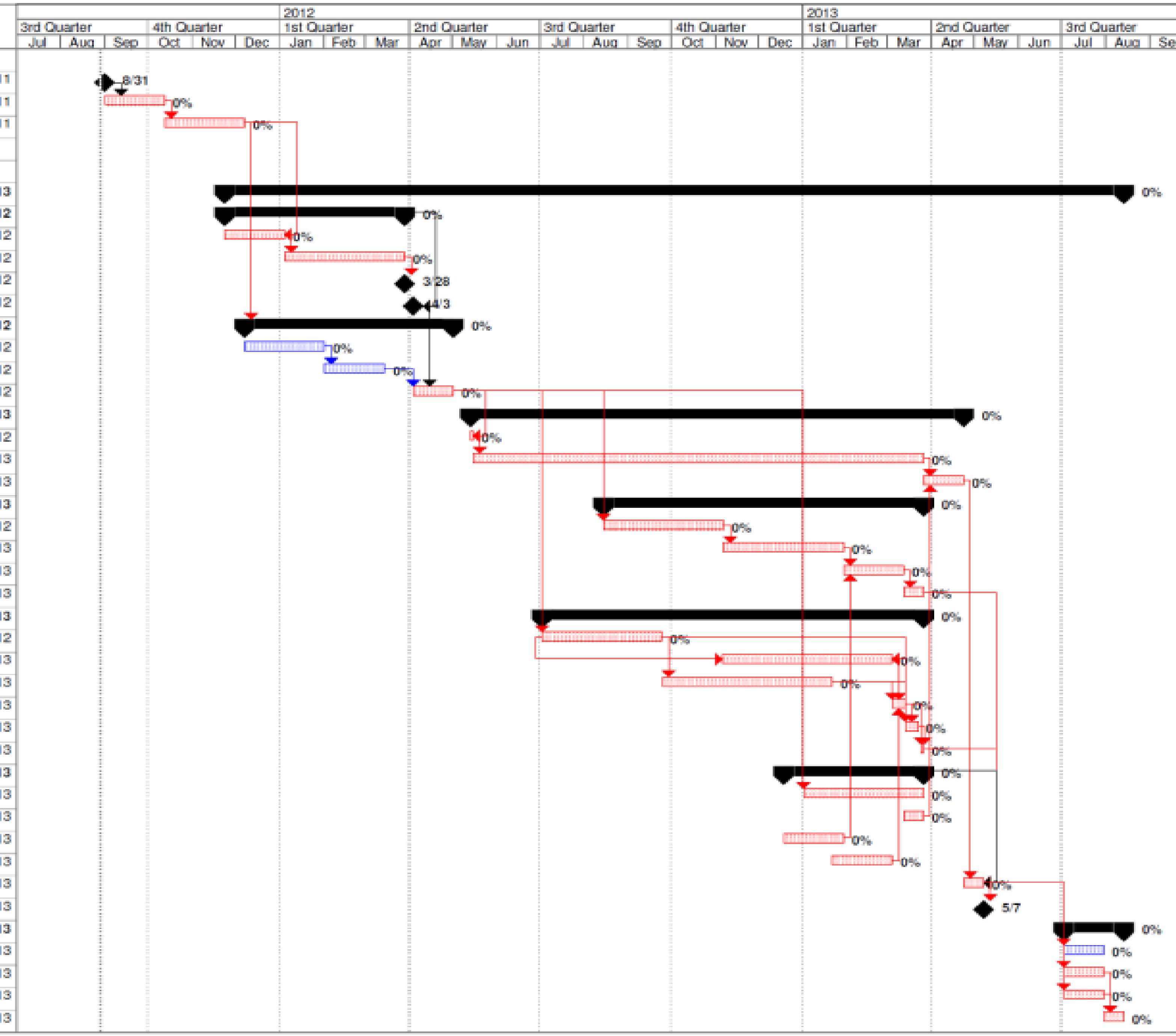
Option Number	2	2A
Option	New 5 x 2 MW Diesel	Used 5 x 2 MW Diesel
GT/Diesel Cost	$8,553	$7,453
Civil Works	$131	$131
Electrical Works	$801	$801
BOP Systems	$129	$129
Existing Unit Demolition & Removal	$7	$7
Sub-Total - Directs and Indirects	$9,620	$8,520
Project Engineering	$513	$458
Project Management	$673	$596
Total	$10,807	$9,575

3.4.10 Schedule

The schedules for the new and nearly new five 2 MW diesel generator are illustrated below. The basic schedule highlights are as follows:

Task	New Diesel Genset	Nearly New Diesel Genset
Review of Options Report	Sept 2011	
Project Approvals and Release	Sept 2011 - Dec 2011	
Engineer, Procure, Construct Contract	May 2012	
In-Service of New 2 x 5 MW GT	May 2013	March 2013
Decommission Existing GT	Aug/Dec 2013	Aug/Dec 2013

ID	Task Name	Duration	Start	Finish
1				
2	Condition Assessment Study	0 wks	Wed 8/31/11	Wed 8/31/11
3	Hydro Internal Capital Budget Proposal Development	6 wks	Thu 9/1/11	Wed 10/12/11
4	Submission - Public Utilities Board & Approval	8 wks	Thu 10/13/11	Wed 12/7/11
5				
6				
7	**New GT or Diesel Units**	**449 days**	**Thu 11/24/11**	**Tue 8/13/13**
8	**Project Environmental & Regulatory Approvals**	**90 days**	**Thu 11/24/11**	**Wed 3/28/12**
9	Prepare Dispersion Modelling & Submission	30 days	Thu 11/24/11	Wed 1/4/12
10	Regulatory Review and Approval	60 days	Thu 1/5/12	Wed 3/28/12
11	Environmental Approval	0 days	Wed 3/28/12	Wed 3/28/12
12	Project Full Release	0 days	Tue 4/3/12	Tue 4/3/12
13	**Request for Proposal (RFP) for Engineer/procure/Cons**	**104 days**	**Thu 12/8/11**	**Tue 5/1/12**
14	Prepare	40 days	Thu 12/8/11	Wed 2/1/12
15	Bid	6 wks	Thu 2/2/12	Wed 3/14/12
16	Award	20 days	Wed 4/4/12	Tue 5/1/12
17	**New Gas Turbien or Diesel Engine Generator**	**247 days**	**Mon 5/14/12**	**Tue 4/23/13**
18	Award Gas Turbine (GT)/Engine Contract	2 days	Mon 5/14/12	Tue 5/15/12
19	Manufacture & Deliver Transportable Engines	45 wks	Wed 5/16/12	Tue 3/26/13
20	Install and Commission	4 wks	Wed 3/27/13	Tue 4/23/13
21	**Fuel System**	**160 days**	**Wed 8/15/12**	**Tue 3/26/13**
22	Engineer	12 wks	Wed 8/15/12	Tue 11/6/12
23	Order, Manufacture, Deliver	12 wks	Wed 11/7/12	Tue 1/29/13
24	Install new fuel lines and receiving system	6 wks	Wed 1/30/13	Tue 3/12/13
25	Commission System	2 wks	Wed 3/13/13	Tue 3/26/13
26	**Electrical & Control Systmes**	**191 days**	**Tue 7/3/12**	**Tue 3/26/13**
27	Engineer	12 wks	Tue 7/3/12	Mon 9/24/12
28	Order & Manufacture Elect & Control (E&C) Equip	17 wks	Tue 11/6/12	Mon 3/4/13
29	Electrical Building Manufacture, Delivery, Install	17 wks	Tue 9/25/12	Mon 1/21/13
30	Install New System	7 days	Tue 3/5/13	Wed 3/13/13
31	RE-align Existing Plant Systems	7 days	Thu 3/14/13	Fri 3/22/13
32	Commission unit	2 days	Mon 3/25/13	Tue 3/26/13
33	**Site Civil Work**	**70 days**	**Wed 12/19/12**	**Tue 3/26/13**
34	Engineer	12 wks	Wed 1/2/13	Tue 3/26/13
35	Generator area clearing and civil	2 wks	Wed 3/13/13	Tue 3/26/13
36	Fuel line civil work	6 wks	Wed 12/19/12	Tue 1/29/13
37	Electrical an contro cable civil work	6 wks	Tue 1/22/13	Mon 3/4/13
38	Complete Unit Test	10 days	Wed 4/24/13	Tue 5/7/13
39	Gas Turbine (GT) In-Service (I/S)	0 days	Tue 5/7/13	Tue 5/7/13
40	**Decommission Existing GT**	**30 days**	**Wed 7/3/13**	**Tue 8/13/13**
41	Fuel delivery system	4 wks	Wed 7/3/13	Tue 7/30/13
42	Electrical & Controls	4 wks	Wed 7/3/13	Tue 7/30/13
43	GT	4 wks	Wed 7/3/13	Tue 7/30/13
44	Building	2 wks	Wed 7/31/13	Tue 8/13/13



Project: Project1 New.mpp
Date: Mon 8/29/11

Critical	Task	Baseline	Milestone	Project Summary
Critical Split	Split	Baseline Split	Summary Progress	External Tasks
Critical Progress	Task Progress	Baseline Milestone	Summary	External Milestone
				Deadline

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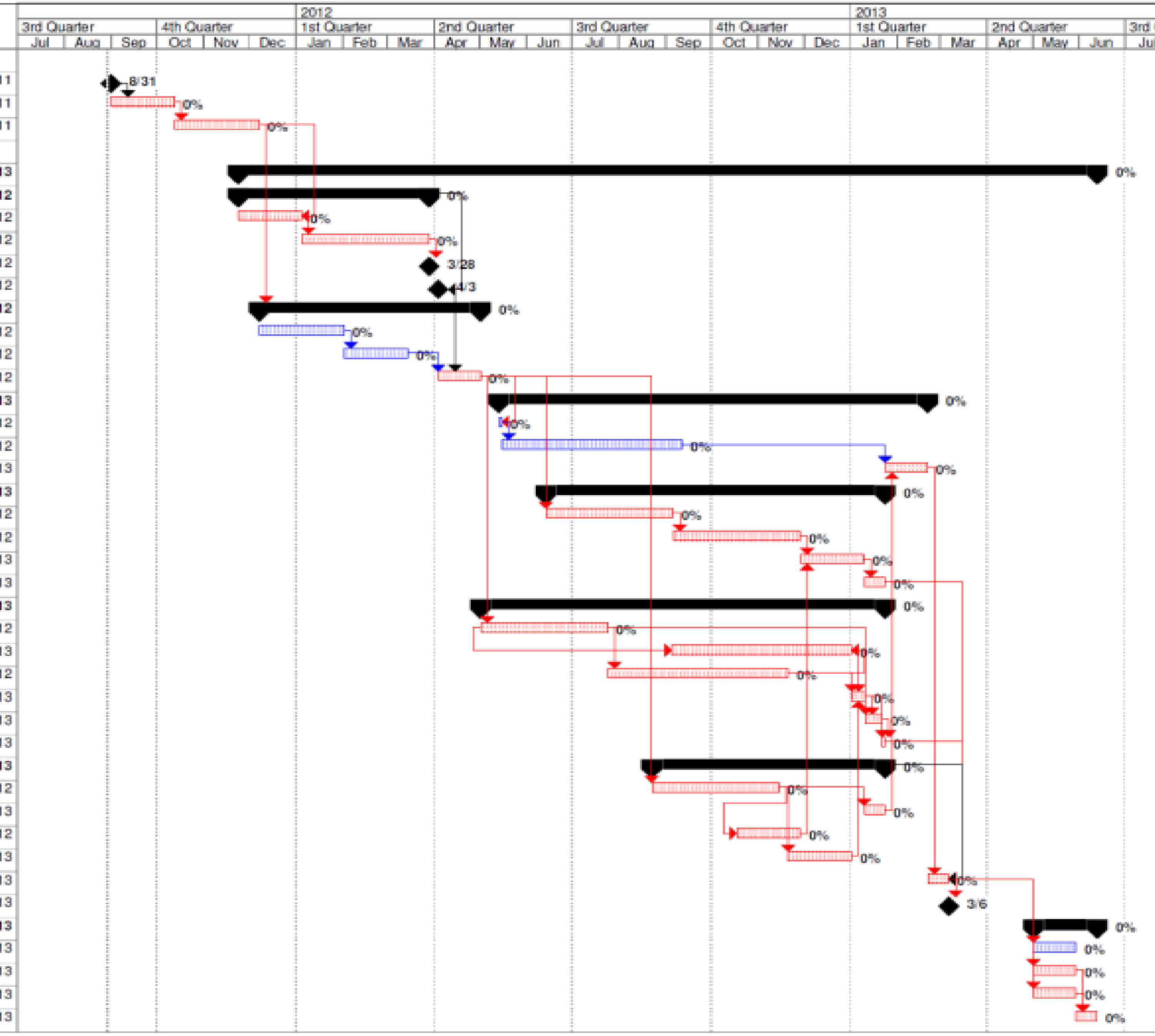
FIGURE 3-7 SCHEDULE – NEW DIESEL GENSET

ID		Task Name	Duration	Start	Finish
1					
2		Condition Assessment Study	0 wks	Wed 8/31/11	Wed 8/31/11
3		Hydro Internal Capital Budget Proposal Development	6 wks	Thu 9/1/11	Wed 10/12/11
4		Submission - Public Utilities Board & Approval	8 wks	Thu 10/13/11	Wed 12/7/11
5					
6		**Nearly New gas Turbine (GT) or Diesel Generator Units**	**405 days**	**Thu 11/24/11**	**Wed 6/12/13**
7		**Project Environmental & Regulatory Approvals**	**90 days**	**Thu 11/24/11**	**Wed 3/28/12**
8		Prepare Dispersion Modelling & Submission	30 days	Thu 11/24/11	Wed 1/4/12
9		Regulatory Review and Approval	60 days	Thu 1/5/12	Wed 3/28/12
10		Environmental Approval	0 days	Wed 3/28/12	Wed 3/28/12
11		Project Full Release	0 days	Tue 4/3/12	Tue 4/3/12
12		**Request for Proposal (RFP) for Engineer/Procure/Construct (**	**104 days**	**Thu 12/8/11**	**Tue 5/1/12**
13		Prepare	40 days	Thu 12/8/11	Wed 2/1/12
14		Bid	6 wks	Thu 2/2/12	Wed 3/14/12
15		Award	20 days	Wed 4/4/12	Tue 5/1/12
16		**Nearly New GT or Diesel Engine Generator**	**203 days**	**Mon 5/14/12**	**Wed 2/20/13**
17		Award GT/Diesel Engine Contract	2 days	Mon 5/14/12	Tue 5/15/12
18		Manufacture & Deliver Transportable Engines	17 wks	Wed 5/16/12	Tue 9/11/12
19		Install and Commission	4 wks	Thu 1/24/13	Wed 2/20/13
20		**Fuel System**	**160 days**	**Thu 6/14/12**	**Wed 1/23/13**
21		Engineer	12 wks	Thu 6/14/12	Wed 9/5/12
22		Order, Manufacture, Deliver	12 wks	Thu 9/6/12	Wed 11/28/12
23		Install new fuel lines and receiving system	6 wks	Thu 11/29/12	Wed 1/9/13
24		Commission System	2 wks	Thu 1/10/13	Wed 1/23/13
25		**Electrical & Control Systmes**	**191 days**	**Wed 5/2/12**	**Wed 1/23/13**
26		Engineer	12 wks	Wed 5/2/12	Tue 7/24/12
27		Order & Manufacture Elect & Control (E&C) Equip	17 wks	Wed 9/5/12	Tue 1/1/13
28		Electrical Building Manufacture, Delivery, Install	17 wks	Wed 7/25/12	Tue 11/20/12
29		Install New System	7 days	Wed 1/2/13	Thu 1/10/13
30		RE-align Existing Plant Systems	7 days	Fri 1/11/13	Mon 1/21/13
31		Commission unit	2 days	Tue 1/22/13	Wed 1/23/13
32		**Site Civil Work**	**110 days**	**Thu 8/23/12**	**Wed 1/23/13**
33		Engineer	12 wks	Thu 8/23/12	Wed 11/14/12
34		Generator area clearing and civil	2 wks	Thu 1/10/13	Wed 1/23/13
35		Fuel line civil work	6 wks	Thu 10/18/12	Wed 11/28/12
36		Electrical an contro cable civil work	6 wks	Wed 11/21/12	Tue 1/1/13
37		Complete Unit Test	10 days	Thu 2/21/13	Wed 3/6/13
38		GT In-Service (I/S)	0 days	Wed 3/6/13	Wed 3/6/13
39		**Decommission Existing GT**	**30 days**	**Thu 5/2/13**	**Wed 6/12/13**
40		Fuel delivery system	4 wks	Thu 5/2/13	Wed 5/29/13
41		Electrical & Controls	4 wks	Thu 5/2/13	Wed 5/29/13
42		GT	4 wks	Thu 5/2/13	Wed 5/29/13
43		Building	2 wks	Thu 5/30/13	Wed 6/12/13



Project: Project1 Nearly New.mpp
Date: Mon 8/29/11

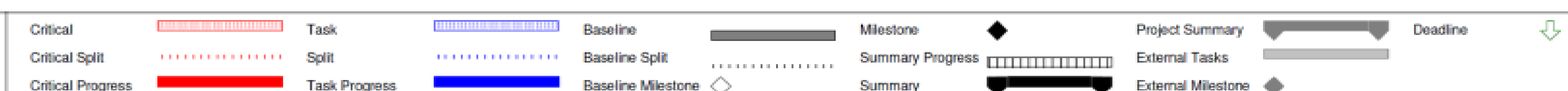


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FIGURE 3-8 SCHEDULE – NEW DIESEL GENSET

3.4.11 OMA Cost Estimate to 2020

Operating costs were assumed to include the ongoing maintenance costs (annual inspections, repairs, etc.), the operations costs (costs to run the unit on test), the fuelling costs (fuel costs to run the tests), and an electricity value credit. The operating costs shown are the same for both the new and nearly new cases. For the kind of operation required, peak and emergency operation (typically <=60 Hrs/Yr, the diesel packages normally would require only an annual service and inspection by qualified service personnel. Most utilities would exercise the equipment once a month to verify proper operation.

The costs were assumed to include the ongoing maintenance costs (annual inspections, repairs, etc.), the operations costs (costs to run the unit on test), the fuelling costs (fuel costs to run the tests), and an electricity value credit. The assumptions used for fuel, operations, and electricity value are illustrated below. The electricity value is premised on receiving the same value per MWh as the existing units would if they were to recover their fuelling costs plus marginal operating and maintenance costs. The fuelling and electricity prices are intended as representative and based on running the units 150 hours per year, whereas actual hours could be as half of this.. The actual values (average run capacity, sent out heat rate (SOHR) and hence fuel and electricity depend on how the testing is actually done.

TABLE 3-19 NEW DIESEL GENSET – OMA COST ASSUMPTION

Assumptions

		Fuelling
#2 Oil Fuel Price (A)	$/MMBTU	$21.47
Unit Efficiency (B)	BTU/kWh	13,656
Average Running Capacity (C)	MW	4
Average Running Cost (D) = AxBxC/1000	$/Hr	$1,173
Electricity Value (E) = Value for existing GT	$/MWh	$343
Electricity Value (F) = E*C	$/Hr OP	$1,373

Operations	
2	Persons/Start (U)
4	Hrs/Start (V)
$70	$/PersonHr (W)
$560	$/Start (Z) = UxVxW

The resulting costs are:

TABLE 3-20 NEW DIESEL GENSET – OMA COSTS

New/Near New Diesel
1000's Cnd $ - 2011/Yr

	Maintenance	Operations	Fuelling	Sub-Total	Electricity Value	Total
2012	$15	$0	$0	$15	$0	$15
2013	$20	$40	$155	$215	($206)	$9
2014	$20	$40	$155	$215	($206)	$9
2015	$20	$40	$155	$215	($206)	$9
2016	$20	$40	$155	$215	($206)	$9
2017	$20	$40	$155	$215	($206)	$9
2018	$20	$40	$155	$215	($206)	$9
2019	$20	$40	$155	$215	($206)	$9
2020	$0	$40	$155	$195	($206)	($11)
TOTAL	$155	$323	$1,237	$1,714	($1,648)	$67

4 COMPARATIVE ANALYSIS OF OPTIONS

4.1 Economic Assumptions

4.1.1 Economic Parameters

The economic parameter values used for escalation rate (general, fuel, electricity rate), and discount rate (escalated and unescalated) are illustrated below, as well as the associated cumulative factors.

TABLE 4-1 ECONOMIC FACTORS

	Escalation		Discount Rate (Escalated $)		Real Discount Rate (UnEscalated $)		Fuel Escalation		Electricity Value Escalation	
Year	Escalation	Cumulative Escalation Factor	Discount Rate (Escalated $)	Discount Factor (Escalated $)	Discount Rate (UnEscalated $)	Discout Factor (Unescalated $)	Fuel Escalation Rate	Cumulative Fuel Escalation Factor	Electricity Value Escalation Rate	Cumulative Electricity Value Factor
	"A"	"B" = Previous B x (1+A)	"C"	"D" = Previous D x 1/(1+C)	"E" = "C"-"A"	"F" =Previous F x 1/(1+E)	"G"	"H" = Previous H x (1+G)	"I"	"J" = Previous J x (1+I)
2011	0.00%	1.000	10.00%	1.000	7.50%	1.000	0.00%	1.000	0.00%	1.000
2012	2.50%	1.025	10.00%	0.909	7.50%	0.930	3.00%	1.030	3.00%	1.030
2013	2.50%	1.051	10.00%	0.826	7.50%	0.865	3.00%	1.061	3.00%	1.061
2014	2.50%	1.077	10.00%	0.751	7.50%	0.805	3.00%	1.093	3.00%	1.093
2015	2.50%	1.104	10.00%	0.683	7.50%	0.749	3.00%	1.126	3.00%	1.126
2016	2.50%	1.131	10.00%	0.621	7.50%	0.697	3.00%	1.159	3.00%	1.159
2017	2.50%	1.160	10.00%	0.564	7.50%	0.648	3.00%	1.194	3.00%	1.194
2018	2.50%	1.189	10.00%	0.513	7.50%	0.603	3.00%	1.230	3.00%	1.230
2019	2.50%	1.218	10.00%	0.467	7.50%	0.561	3.00%	1.267	3.00%	1.267
2020	2.50%	1.249	10.00%	0.424	7.50%	0.522	3.00%	1.305	3.00%	1.305

4.1.2 Economic Values - Failure to Operate

The analysis assumed a relative difference in the relative probability of failure to perform as required (with Option 1 – the New 2 x 5 MW GTG as the base against which the others are compared). This is based on the reasons provided previously.

TABLE 4-2 ECONOMIC VALUES – FAILURE TO OPERATE ASSUMPTION

Failure To Operate		% Probability once over 2013-2020	Value of Hr Shutdown	# Hrs Per Shutdown	Probable $/Incident
		% (A)	MM$/Hr (B)	Hrs (C)	MM$ (D) = AxBxC
Option 0	Refurbished Unit	10%	$5	20	$10
Option1 & 1A	New/Used 2 x 5 MW GT	0%	$5	20	$0
Option 2 & 2A	New/Used 5x2 MW Diesel	4%	$5	20	$4

Notes:
Value/ Hr Shutdown = $5 MM (Impact to Newfoundland Economy)
Probability risk is relative to the new 2 x 5MW GT option
One occurrence assumed nominally in 2016
Probable $/incident increases proportional to (A), (B), or (C)

4.1.3 Economic Values –Terminal Values

Each of the options has a "terminal value" at the end of the 2020 period. The amount is a function of both the age and condition and market value of the units at that time, and/or of its internal value for redeployment for other uses within Hydro post 2020 (i.e. regional distribution line outage/maintenance support). Potential short term alternative uses prior to 2020 may also have value, but were not assessed. The terminal values assumed for the study are shown in Table 4-4.

TABLE 4-3 OPTION TERMINAL VALUES IN 2020

Option	Purchased Equipment Cost M$	System Terminal Value in 2020 M$	Comment
Option 0 - Refurbished Existing Unit	$3.0	$0	Terminal value covers cost for demolition
Option 1 - New 2 x 5 MW GT	$10.9	$7.0	Low use, essentially new condition.
Option 1A - Nearly New 2 x 5 MW GT	$9.2	$4.0	Lower percent recovery than new given prior use.
Option 2 - New 5 x 2 MW Diesel Genset	$8.6	$5.0	Lower market value – more available.
Option 2A - Nearly New 5 x 2 MW Diesel Genset	$7.5	$3.0	Lower percent recovery than new given prior use.

4.2 Capital Cost Comparison

Table 4-4 provides an overview of the total capital cost of the options.

<u>Option 0, Existing GTG Unit</u>

For Option 0, the existing GT Unit refurbishment, there are three relevant values.

- The base total ($4.462M) does not address the replacement of the unit's capacity during its extensive overhaul outage (12 to 22 weeks).
- The second case ("+ standby") is based on the assumption that a "replacement gas generator and power turbine" are leased and substituted for the current equipment during the overhaul outage. There is a strong likelihood that this is possible. It is assumed that other issues (gearbox oil leaks etc are fixed in relatively short time on site). It is unlikely that other major equipment such as a gearbox could be leased.
- The third option ("+ Rental Stby") assumes that two new 5 MW trailer mounted gas turbines are leased for the outage period and the necessary facilities to connect them installed. This is a very expensive option and auxiliary systems will have limited useful life. It is also likely to significantly extend the schedule. It is not seen as a viable option to pursuing Option 1 or 1A.

<u>Options 1 and 2, New and Nearly New, Used Gas Turbine Generator and Diesel Generator Units</u>

The difference in the New and Nearly New is mostly in the capital costs. It should be noted that there may be some additional costs required to retrofit nearly new units to meet the same or required standards as the new units that are designed to meet Holyrood requirements.

TABLE 4-4 CAPITAL COST COMPARISON OF OPTIONS

Capital Cost Comparison
Capital cost estimate $1,000 Can 2011

Option Number	**0**	**1**	**1A**	**2**	**2A**
Option	**Existing GT Refurb**	**New 2 x 5 MW GT**	**Used 2 x 5 MW GT**	**New 5 x 2 MW Diesel**	**Used 5 x 2 MW Diesel**
GT/Diesel Cost	$2,950	$10,865	$9,234	$8,553	$7,453
Civil Works	$224	$131	$131	$131	$131
Electrical Works	$541	$759	$759	$801	$801
BOP Systems	$330	$129	$129	$129	$129
Existing Unit Demolition & Removal	$0	$7	$7	$7	$7
Sub-Total - Directs and Indirects	$4,046	$11,891	$10,260	$9,620	$8,520
Project Engineering	$324	$625	$544	$513	$458
Project Management	$283	$832	$718	$673	$596
Total	$4,652	$13,348	$11,522	$10,807	$9,575

+ Standby = Total	$4,825
+ New Rental Stdby = Total	$9,421

4.3 Operating Cost Comparison

Operating costs were assumed to include the ongoing maintenance costs (annual inspections, repairs, etc.), the operations costs (costs to run the unit on test), the fuelling costs (fuel costs to run the tests), and an electricity value credit.

For Option 0, Existing GTG Unit

The operating costs are shown for both a refurbished case and a non-refurbished case. The assumptions used for fuel, operations, and electricity value are illustrated below. The electricity value is premised on recovering fuelling costs plus marginal operating costs.

TABLE 4-5 OMA ASSUMPTIONS – OPTION 0, EXISTING GTG

Assumptions

		Fuelling
#2 Oil Fuel Price (A)	$/MMBTU	$21.47
Unit Efficiency (B)	BTU/kWh	13,656
Average Running Capacity (C)	MW	4
Average Running Cost (D) = AxBxC/1000	$/Hr	$1,173
Electricity Value (E) = AxB/1000 + $50 Mtce	$/MWh	$343
Electricity Value (F) = E*C	$/Hr OP	$1,373

Operations	
2	Persons/Start (U)
4	Hrs/Start (V)
$70	$/PersonHr (W)
$560	$/Start (Z) = UxVxW

The non-refurbished case includes an assumption of an equipment failure with modest consequential damage in 2016.

TABLE 4-6 OMA COSTS – OPTION 0, EXISTING GTG

Existing Unit
1000's Cnd $ - 2011/Yr

	Maintenance		Operations		Fuelling		Sub-Total		Electricity Value		Total	
	With Rehab	Without Rehab	With Rehab	Without Rehab	With Rehab	Without Rehab	With Rehab	Without Rehab	With Rehab	Without Rehab	With Rehab	Without Rehab
2012	$15	$15	$0	$0	$0	$0	$15	$15	$0	$0	$15	$15
2013	$20	$15	$40	$0	$176	$0	$236	$15	($206)	$0	$30	$15
2014	$20	$15	$40	$0	$176	$0	$236	$15	($206)	$0	$30	$15
2015	$20	$15	$40	$0	$176	$0	$236	$15	($206)	$0	$30	$15
2016	$20	$1,500	$40	$1	$176	$88	$236	$1,589	($206)	($103)	$30	$1,486
2017	$20	$15	$40	$0	$176	$0	$236	$15	($206)	$0	$30	$15
2018	$20	$15	$40	$0	$176	$0	$236	$15	($206)	$0	$30	$15
2019	$20	$15	$40	$0	$176	$0	$236	$15	($206)	$0	$30	$15
2020	$0	$0	$40	$0	$176	$0	$216	$0	($206)	$0	$10	$0
TOTAL	$155	$1,605	$323	$1	$1,408	$88	$1,885	$1,694	($1,648)	($103)	$238	$1,591

For Option 1 and 1A – New and Nearly New 2 x 5MW GTG

The operating costs shown are the same for both the new and nearly new cases. The difference in the New and Nearly New is mostly in the capital costs. The vendor indicated that for the 6 month inspection the cost was to be 10,000 and for the yearly it was 18,000 and that these costs would be the same for both new and nearly new.

The assumptions used for fuel, operations, and electricity value are illustrated below. The electricity value is premised on recovering fuelling costs plus marginal operating costs.

TABLE 4-7 OMA ASSUMPTIONS – OPTION 1, NEW TRANSPORTABLE GTG

Assumptions

#2 Oil Fuel Price (A)	$/MMBTU	$21.47
Unit Efficiency (B)	BTU/kWh	12,000
Average Running Capacity (C)	MW	4
Average Running Cost (D) = AxBxC/1000	$/Hr	$1,031
Electricity Value (E) = Value for existing GT	$/MWh	$343.25
Electricity Value (F) = E*C	$/Hr OP	$1,373

2	Persons/Start (U)
4	Hrs/Start (V)
$70	$/PersonHr (W)
$560	$/Start (Z) = UxVxW

The resulting costs are:

TABLE 4-8 OMA COSTS – OPTION 1, NEW TRANSPORTABLE GTG

New/Near New GT
1000's Cnd $ - 2011/Yr

	Maintenance	Operations	Fuelling	Sub-Total	Electricity Value		Total
2012	$15	$0	$0	$15	$0		$15
2013	$20	$40	$155	$215	($206)		$9
2014	$20	$40	$155	$215	($206)		$9
2015	$20	$40	$155	$215	($206)		$9
2016	$20	$40	$155	$215	($206)		$9
2017	$20	$40	$155	$215	($206)		$9
2018	$20	$40	$155	$215	($206)		$9
2019	$20	$40	$155	$215	($206)		$9
2020	$0	$40	$155	$195	($206)		($11)
TOTAL	$155	$323	$1,237	$1,714	($1,648)		$67

For Option 2 and 2A – New and Nearly New 5 x 2MW Diesel Engine Generators

The operating costs shown are the same for both the new and nearly new cases. The difference in the New and Nearly New is mostly in the capital costs.

The assumptions used for fuel, operations, and electricity value are illustrated below. The electricity value is premised on recovering fuelling costs plus marginal operating costs.

TABLE 4-9 OMA ASSUMPTIONS – OPTION 2, NEW DIESEL GENSET

Assumptions

		Fuelling
#2 Oil Fuel Price (A)	$/MMBTU	$21.47
Unit Efficiency (B)	BTU/kWh	13,656
Average Running Capacity (C)	MW	4
Average Running Cost (D) = AxBxC/1000	$/Hr	$1,173
Electricity Value (E) = Value for existing GT	$/MWh	$343
Electricity Value (F) = E*C	$/Hr OP	$1,373

Operations	
2	Persons/Start (U)
4	Hrs/Start (V)
$70	$/PersonHr (W)
$560	$/Start (Z) = UxVxW

The resulting costs are:

TABLE 4-10 OMA COSTS – OPTION 2, NEW DIESEL GENSET

New/Near New Diesel
1000's Cnd $ - 2011/Yr

	Maintenance	Operations	Fuelling	Sub-Total	Electricity Value	Total
2012	$15	$0	$0	$15	$0	$15
2013	$20	$40	$155	$215	($206)	$9
2014	$20	$40	$155	$215	($206)	$9
2015	$20	$40	$155	$215	($206)	$9
2016	$20	$40	$155	$215	($206)	$9
2017	$20	$40	$155	$215	($206)	$9
2018	$20	$40	$155	$215	($206)	$9
2019	$20	$40	$155	$215	($206)	$9
2020	$0	$40	$155	$195	($206)	($11)
TOTAL	$155	$323	$1,237	$1,714	($1,648)	$67

4.4 Life Cycle Cost Comparison

Table 4-11 presents a summary of the life cycle cost comparison of the options in 1) un-escalated non-discounted (not present worthed), 2) un-escalated discounted (present worthed), 3) escalated non-discounted (not present worthed), and 4) escalated discounted (present worthed) costs.

The existing unit refurbishment option costs include the lower cost standby option, assuming that a replacement gas generator and power turbine are leased and installed while the existing units are sent out for refurbishment. This adds only about $200,000 to the base cost.

The existing unit refurbishment option costs assuming the standby option using a complete, installed 2 x 5 MW nearly new GT leased option would add an additional $4.6 M.

The options include a cost for differences in the likelihood of a failure occurring once during the period – an additional $10 million in 2016 for the existing GTG and $3 to 4 million for the 5 x 2 MW diesel options.

TABLE 4-11 LIFE CYCLE COST COMPARISON SUMMARY

		Refurbished Unit, Use of Spare Gas Generator & Power Turbine					
		Capital Cost	OMA	Fuel	Sub-Total	Elect Value	Total
1	UNESCALATED	$14,825	$1,885	$1,408	$18,118	($1,648)	$16,470
2	UNESCALATED, DISCOUTED CASHFLOW	$11,454	$1,291	$959	$13,704	($1,122)	$12,582
3	ESCALATED CASHFLOW	$16,260	$2,159	$1,660	$20,079	($1,943)	$18,136
4	ESCALATED, DISCOUTED CASHFLOW	$11,521	$1,302	$992	$13,815	($1,161)	$12,654

		Option 1 New 2x5 MW GT					
		Capital Cost	OMA	Fuel	Sub-Total	Elect Value	Total
1	UNESCALATED	$6,348	$1,714	$1,237	$9,300	($1,648)	$7,652
2	UNESCALATED, DISCOUTED CASHFLOW	$8,766	$1,175	$842	$10,783	($1,122)	$9,661
3	ESCALATED CASHFLOW	$4,940	$1,963	$1,459	$8,362	($1,943)	$6,419
4	ESCALATED, DISCOUTED CASHFLOW	$8,731	$1,185	$871	$10,787	($1,161)	$9,626

	Option 1A Used 2x5 MW GT					
	Capital Cost	OMA	Fuel	Sub-Total	Elect Value	Total
1	$7,522	$1,714	$1,237	$10,473	($1,648)	$8,826
2	$8,632	$1,175	$842	$10,649	($1,122)	$9,527
3	$6,815	$1,963	$1,459	$10,236	($1,943)	$8,294
4	$8,618	$1,185	$871	$10,674	($1,161)	$9,513

		Option 2 New 5x2MW Diesel					
		Capital Cost	OMA	Fuel	Sub-Total	Elect Value	Total
1	UNESCALATED	$9,807	$323	$1,237	$11,366	($1,648)	$9,719
2	UNESCALATED, DISCOUTED CASHFLOW	$10,231	$220	$842	$11,293	($1,122)	$10,171
3	ESCALATED CASHFLOW	$9,358	$370	$1,459	$11,187	($1,943)	$9,244
4	ESCALATED, DISCOUTED CASHFLOW	$10,232	$222	$871	$11,325	($1,161)	$10,164

	Option 2A Used 5x2MW Diesel					
	Capital Cost	OMA	Fuel	Sub-Total	Elect Value	Total
1	$10,575	$323	$1,237	$12,134	($1,648)	$10,487
2	$10,128	$220	$842	$11,190	($1,122)	$10,068
3	$10,593	$370	$1,459	$12,422	($1,943)	$10,479
4	$10,143	$222	$871	$11,236	($1,161)	$10,075

The details of the un-escalated non-discounted (not present worthed) and unescalated discounted (present worthed) tables for the options, using the assumption in Section 4.1, are as follows:

TABLE 4-12 LIFE CYCLE COST COMPARISON (UNESCALATED, NOT-DISCOUNTED AND DISCOUNTED)

UNESCALATED, NOT DISCOUNTED CASHFLOW

Refurbished Unit, Use of Spare Gas Generator & Power Turbine

	Capital Cost	OMA	Fuel	Sub-Total	Elect Value	Total
2011		$0	$0	$0	$0	$0
2012	$4,825	$15	$0	$4,840	$0	$4,840
2013		$236	$176	$412	($206)	$206
2014		$236	$176	$412	($206)	$206
2015		$236	$176	$412	($206)	$206
2016	$10,000	$236	$176	$10,412	($206)	$10,206
2017		$236	$176	$412	($206)	$206
2018		$236	$176	$412	($206)	$206
2019		$236	$176	$412	($206)	$206
2020	$0	$216	$176	$392	($206)	$186
Total	$14,825	$1,885	$1,408	$18,118	($1,648)	$16,470

Option 1 New 2x5 MW GT

	Capital Cost	OMA	Fuel	Sub-Total	Elect Value	Total
2011		$0	$0	$0	$0	$0
2012	$13,348	$15	$0	$13,363	$0	$13,363
2013		$215	$155	$370	($206)	$164
2014		$215	$155	$370	($206)	$164
2015		$215	$155	$370	($206)	$164
2016	$0	$215	$155	$370	($206)	$164
2017		$215	$155	$370	($206)	$164
2018		$215	$155	$370	($206)	$164
2019		$215	$155	$370	($206)	$164
2020	($7,000)	$195	$155	($6,650)	($206)	($6,856)
Total	$6,348	$1,714	$1,237	$9,300	($1,648)	$7,652

Option 1A Used 2x5 MW GT

	Capital Cost	OMA	Fuel	Sub-Total	Elect Value	Total
2011		$0	$0	$0	$0	$0
2012	$11,522	$15	$0	$11,537	$0	$11,537
2013		$215	$155	$370	($206)	$164
2014		$215	$155	$370	($206)	$164
2015		$215	$155	$370	($206)	$164
2016	$0	$215	$155	$370	($206)	$164
2017		$215	$155	$370	($206)	$164
2018		$215	$155	$370	($206)	$164
2019		$215	$155	$370	($206)	$164
2020	($4,000)	$195	$155	($3,650)	($206)	($3,856)
Total	$7,522	$1,714	$1,237	$10,473	($1,648)	$8,826

Option 2 New 5 x 2 MW Diesel

	Capital Cost	OMA	Fuel	Sub-Total	Elect Value	Total
2011		$0	$0	$0	$0	$0
2012	$10,807	$0	$0	$10,807	$0	$10,807
2013		$40	$155	$195	($206)	($11)
2014		$40	$155	$195	($206)	($11)
2015		$40	$155	$195	($206)	($11)
2016	$4,000	$40	$155	$4,195	($206)	$3,989
2017		$40	$155	$195	($206)	($11)
2018		$40	$155	$195	($206)	($11)
2019		$40	$155	$195	($206)	($11)
2020	($5,000)	$40	$155	($4,805)	($206)	($5,011)
Total	$9,807	$323	$1,237	$11,366	($1,648)	$9,719

Option 2A used 5 x 2 MW Diesel

	Capital Cost	OMA	Fuel	Sub-Total	Elect Value	Total
2011		$0	$0	$0	$0	$0
2012	$9,575	$0	$0	$9,575	$0	$9,575
2013		$40	$155	$195	($206)	($11)
2014		$40	$155	$195	($206)	($11)
2015		$40	$155	$195	($206)	($11)
2016	$4,000	$40	$155	$4,195	($206)	$3,989
2017		$40	$155	$195	($206)	($11)
2018		$40	$155	$195	($206)	($11)
2019		$40	$155	$195	($206)	($11)
2020	($3,000)	$40	$155	($2,805)	($206)	($3,011)
Total	$10,575	$323	$1,237	$12,134	($1,648)	$10,487

UNESCALATED, DISCOUTED CASHFLOW

Refurbished Unit, Use of Spare Gas Generator & Power Turbine

	Capital Cost	OMA	Fuel	Sub-Total	Elect Value	Total
2011	$0	$0	$0	$0	$0	$0
2012	$4,489	$14	$0	$4,502	$0	$4,502
2013	$0	$204	$152	$357	($178)	$178
2014	$0	$190	$142	$332	($166)	$166
2015	$0	$177	$132	$309	($154)	$154
2016	$6,966	$165	$123	$7,253	($143)	$7,109
2017	$0	$153	$114	$267	($133)	$134
2018	$0	$142	$106	$248	($124)	$124
2019	$0	$132	$99	$231	($115)	$116
2020	$0	$113	$92	$205	($107)	$97
Total	$11,454	$1,291	$959	$13,704	($1,122)	$12,582

Option 1 New 2x5 MW GT

	Capital Cost	OMA	Fuel	Sub-Total	Elect Value	Total
2011	$0	$0	$0	$0	$0	$0
2012	$12,417	$14	$0	$12,431	$0	$12,431
2013	$0	$186	$134	$320	($178)	$142
2014	$0	$173	$124	$297	($166)	$132
2015	$0	$161	$116	$277	($154)	$123
2016	$0	$150	$108	$257	($143)	$114
2017	$0	$139	$100	$239	($133)	$106
2018	$0	$130	$93	$223	($124)	$99
2019	$0	$121	$87	$207	($115)	$92
2020	($3,651)	$102	$81	($3,469)	($107)	($3,576)
Total	$8,766	$1,175	$842	$10,783	($1,122)	$9,661

Option 1A Used 2x5 MW GT

	Capital Cost	OMA	Fuel	Sub-Total	Elect Value	Total
2011	$0	$0	$0	$0	$0	$0
2012	$10,718	$14	$0	$10,732	$0	$10,732
2013	$0	$186	$134	$320	($178)	$142
2014	$0	$173	$124	$297	($166)	$132
2015	$0	$161	$116	$277	($154)	$123
2016	$0	$150	$108	$257	($143)	$114
2017	$0	$139	$100	$239	($133)	$106
2018	$0	$130	$93	$223	($124)	$99
2019	$0	$121	$87	$207	($115)	$92
2020	($2,086)	$102	$81	($1,904)	($107)	($2,011)
Total	$8,632	$1,175	$842	$10,649	($1,122)	$9,527

Option 2 New 5 x 2 MW Diesel

	Capital Cost	OMA	Fuel	Sub-Total	Elect Value	Total
2011	$0	$0	$0	$0	$0	$0
2012	$10,053	$0	$0	$10,053	$0	$10,053
2013	$0	$35	$134	$169	($178)	($10)
2014	$0	$32	$124	$157	($166)	($9)
2015	$0	$30	$116	$146	($154)	($8)
2016	$2,786	$28	$108	$2,922	($143)	$2,779
2017	$0	$26	$100	$126	($133)	($7)
2018	$0	$24	$93	$117	($124)	($7)
2019	$0	$23	$87	$109	($115)	($6)
2020	($2,608)	$21	$81	($2,506)	($107)	($2,614)
Total	$10,231	$220	$842	$11,293	($1,122)	$10,171

Option 2A used 5 x 2 MW Diesel

	Capital Cost	OMA	Fuel	Sub-Total	Elect Value	Total
2011	$0	$0	$0	$0	$0	$0
2012	$8,907	$0	$0	$8,907	$0	$8,907
2013	$0	$35	$134	$169	($178)	($10)
2014	$0	$32	$124	$157	($166)	($9)
2015	$0	$30	$116	$146	($154)	($8)
2016	$2,786	$28	$108	$2,922	($143)	$2,779
2017	$0	$26	$100	$126	($133)	($7)
2018	$0	$24	$93	$117	($124)	($7)
2019	$0	$23	$87	$109	($115)	($6)
2020	($1,565)	$21	$81	($1,463)	($107)	($1,570)
Total	$10,128	$220	$842	$11,190	($1,122)	$10,068

Based on escalated cost assumptions in Section 4.1, the escalated non-discounted (not present worthed) and escalated discounted (present worthed) tables are as follows.

TABLE 4-13 LIFE CYCLE COST COMPARISON (ESCALATED, NOT DISCOUNTED AND DISCOUNTED, PRESENT VALUED)

ESCALATED, NOT DISCOUNTED CASHFLOW

Refurbished Unit, Use of Spare Gas Generator & Power Turbine

	Capital Cost	OMA	Fuel	Sub-Total	Elect Value	Total
2011	$0	$0	$0	$0	$0	$0
2012	$4,946	$15	$0	$4,961	$0	$4,961
2013	$0	$248	$187	$435	($218)	$216
2014	$0	$254	$192	$447	($225)	$222
2015	$0	$261	$198	$459	($232)	$227
2016	$11,314	$267	$204	$11,785	($239)	$11,547
2017	$0	$274	$210	$484	($246)	$238
2018	$0	$281	$216	$497	($253)	$244
2019	$0	$288	$223	$511	($261)	$250
2020	$0	$270	$230	$500	($269)	$231
Total	$16,260	$2,159	$1,660	$20,079	($1,943)	$18,136

Option 1 New 2x5 MW GT

	Capital Cost	OMA	Fuel	Sub-Total	Elect Value	Total
2011	$0	$0	$0	$0	$0	$0
2012	$13,682	$15	$0	$13,697	$0	$13,697
2013	$0	$226	$164	$390	($218)	$171
2014	$0	$231	$169	$400	($225)	$175
2015	$0	$237	$174	$411	($232)	$179
2016	$0	$243	$179	$422	($239)	$184
2017	$0	$249	$185	$434	($246)	$188
2018	$0	$255	$190	$446	($253)	$192
2019	$0	$262	$196	$458	($261)	$197
2020	($8,742)	$243	$202	($8,297)	($269)	($8,566)
Total	$4,940	$1,963	$1,459	$8,362	($1,943)	$6,419

Option 1A Used 2x5 MW GT

	Capital Cost	OMA	Fuel	Sub-Total	Elect Value	Total
2011	$0	$0	$0	$0	$0	$0
2012	$11,810	$15	$0	$11,826	$0	$11,826
2013	$0	$226	$164	$390	($218)	$171
2014	$0	$231	$169	$400	($225)	$175
2015	$0	$237	$174	$411	($232)	$179
2016	$0	$243	$179	$422	($239)	$184
2017	$0	$249	$185	$434	($246)	$188
2018	$0	$255	$190	$446	($253)	$192
2019	$0	$262	$196	$458	($261)	$197
2020	($4,995)	$243	$202	($4,550)	($269)	($4,819)
Total	$6,815	$1,963	$1,459	$10,236	($1,943)	$8,294

Option 2 New 5 x 2 MW Diesel

	Capital Cost	OMA	Fuel	Sub-Total	Elect Value	Total
2011	$0	$0	$0	$0	$0	$0
2012	$11,077	$0	$0	$11,077	$0	$11,077
2013	$0	$42	$164	$206	($218)	($12)
2014	$0	$43	$169	$212	($225)	($13)
2015	$0	$45	$174	$219	($232)	($13)
2016	$4,526	$46	$179	$4,750	($239)	$4,512
2017	$0	$47	$185	$231	($246)	($15)
2018	$0	$48	$190	$238	($253)	($15)
2019	$0	$49	$196	$245	($261)	($16)
2020	($6,244)	$50	$202	($5,992)	($269)	($6,261)
Total	$9,358	$370	$1,459	$11,187	($1,943)	$9,244

Option 2A used 5 x 2 MW Diesel

	Capital Cost	OMA	Fuel	Sub-Total	Elect Value	Total
2011	$0	$0	$0	$0	$0	$0
2012	$9,814	$0	$0	$9,814	$0	$9,814
2013	$0	$42	$164	$206	($218)	($12)
2014	$0	$43	$169	$212	($225)	($13)
2015	$0	$45	$174	$219	($232)	($13)
2016	$4,526	$46	$179	$4,750	($239)	$4,512
2017	$0	$47	$185	$231	($246)	($15)
2018	$0	$48	$190	$238	($253)	($15)
2019	$0	$49	$196	$245	($261)	($16)
2020	($3,747)	$50	$202	($3,494)	($269)	($3,763)
Total	$10,593	$370	$1,459	$12,422	($1,943)	$10,479

ESCALATED, DISCOUTED CASHFLOW

Refurbished Unit, Use of Spare Gas Generator & Power Turbine

	Capital Cost	OMA	Fuel	Sub-Total	Elect Value	Total
2011	$0	$0	$0	$0	$0	$0
2012	$4,496	$14	$0	$4,510	$0	$4,510
2013	$0	$205	$154	$359	($181)	$179
2014	$0	$191	$144	$336	($169)	$167
2015	$0	$178	$135	$313	($158)	$155
2016	$7,025	$166	$127	$7,318	($148)	$7,170
2017	$0	$155	$119	$273	($139)	$134
2018	$0	$144	$111	$255	($130)	$125
2019	$0	$134	$104	$238	($122)	$117
2020	$0	$115	$97	$212	($114)	$98
Total	$11,521	$1,302	$992	$13,815	($1,161)	$12,654

Option 1 New 2x5 MW GT

	Capital Cost	OMA	Fuel	Sub-Total	Elect Value	Total
2011	$0	$0	$0	$0	$0	$0
2012	$12,438	$14	$0	$12,452	$0	$12,452
2013	$0	$187	$136	$322	($181)	$142
2014	$0	$174	$127	$301	($169)	$132
2015	$0	$162	$119	$281	($158)	$123
2016	$0	$151	$111	$262	($148)	$114
2017	$0	$141	$104	$245	($139)	$106
2018	$0	$131	$98	$229	($130)	$99
2019	$0	$122	$91	$214	($122)	$92
2020	($3,707)	$103	$86	($3,519)	($114)	($3,633)
Total	$8,731	$1,185	$871	$10,787	($1,161)	$9,626

Option 1A Used 2x5 MW GT

	Capital Cost	OMA	Fuel	Sub-Total	Elect Value	Total
2011	$0	$0	$0	$0	$0	$0
2012	$10,737	$14	$0	$10,750	$0	$10,750
2013	$0	$187	$136	$322	($181)	$142
2014	$0	$174	$127	$301	($169)	$132
2015	$0	$162	$119	$281	($158)	$123
2016	$0	$151	$111	$262	($148)	$114
2017	$0	$141	$104	$245	($139)	$106
2018	$0	$131	$98	$229	($130)	$99
2019	$0	$122	$91	$214	($122)	$92
2020	($2,119)	$103	$86	($1,930)	($114)	($2,044)
Total	$8,618	$1,185	$871	$10,674	($1,161)	$9,513

Option 2 New 5 x 2 MW Diesel

	Capital Cost	OMA	Fuel	Sub-Total	Elect Value	Total
2011	$0	$0	$0	$0	$0	$0
2012	$10,070	$0	$0	$10,070	$0	$10,070
2013	$0	$35	$136	$171	($181)	($10)
2014	$0	$33	$127	$160	($169)	($10)
2015	$0	$30	$119	$149	($158)	($9)
2016	$2,810	$28	$111	$2,950	($148)	$2,801
2017	$0	$26	$104	$131	($139)	($8)
2018	$0	$25	$98	$122	($130)	($8)
2019	$0	$23	$91	$114	($122)	($7)
2020	($2,648)	$21	$86	($2,541)	($114)	($2,655)
Total	$10,232	$222	$871	$11,325	($1,161)	$10,164

Option 2A used 5 x 2 MW Diesel

	Capital Cost	OMA	Fuel	Sub-Total	Elect Value	Total
2011	$0	$0	$0	$0	$0	$0
2012	$8,922	$0	$0	$8,922	$0	$8,922
2013	$0	$35	$136	$171	($181)	($10)
2014	$0	$33	$127	$160	($169)	($10)
2015	$0	$30	$119	$149	($158)	($9)
2016	$2,810	$28	$111	$2,950	($148)	$2,801
2017	$0	$26	$104	$131	($139)	($8)
2018	$0	$25	$98	$122	($130)	($8)
2019	$0	$23	$91	$114	($122)	($7)
2020	($1,589)	$21	$86	($1,482)	($114)	($1,596)
Total	$10,143	$222	$871	$11,236	($1,161)	$10,075

5 CONCLUSIONS

5.1 Existing Gas Turbine Generator Unit

1. The existing GT generator should not be operated (started, operated, shutdown) except in an emergency situation, and in such an emergency its operation should be observe remotely to ensure personnel safety.
   - i) Fire from lube oil system gearbox seals remains a possible safety issue.
   - ii) Catastrophic failure of the power turbine disk is a possibility due to corrosion and high stress that may be present at blade roots and attachments
2. The existing GT generator requires extensive overhaul and repair work:
   - x) Power turbine disk may require replacement (9 month manufacturing lead time)
   - xi) One or more power turbine blades may require replacement or significant repair
   - xii) Gas generator blading requires cleaning and recoating
   - xiii) Inlet filter media requires replacement and inlet duct requires refurbishment (including cooling air duct to power turbine disk)
   - xiv) Exhaust stack requires replacement or extensive repairs
   - xv) Gearbox lube oil system requires modification and refurbishment
     - e. Seals require replacement/modification
     - f. Venting system modifications required to reduce lube oil pressure buildup
     - g. Lube oil pump system requires upgrade for start-ups.
     - h. Lube oil cooling fan is experiencing some leaks and snow and ice and water build-ups in its containment can cause start-issues
   - xvi) Gearbox bearings likely worn and need refurbishment or replacement and/or unit re-alignment
   - xvii) Unit generator requires significant testing and possibly rewind
   - xviii) Unit generator exciter needs refurbishment and likely replacement
3. GT electrical and controls system has elements that are not in compliance with current standards and/or are obsolete and hence necessitates replacement:
   - iii) Unit AVR
   - iv) Unit MCC's
4. The GT and generator enclosure rooms require modification to their fire detection and suppression systems to provide better coverage, as evidenced by the failure of the system to initially detect or suppress the gearbox lube oil fire in 2010.
5. GT fuel oil receiving, forwarding, and delivery system are in operable condition, but climatic conditions (icing, snow-buildup, water build-ups from rain, rusting from salty ambient air) result in significant periods where starts may fail or be significantly delayed. The GT generator building is in generally good condition, except for:
   - iv) Major leaks in and around the GT exhaust stack which are impacting the gas turbine power turbine volute and back end blades;
   - v) Minor leaks at generator ventilation stack; and
   - vi) Minor air leaks as a result of minor siding holes (corrosion) which require repair/ refurbishment
6. The electrical services room require expansion to allow for new electrical systems and current systems to be in compliance with current standards (i.e. space, separation distance for arc flash).

7. The earliest in-service dates for refurbishing the existing unit and returning it to service:
    a. Without back-up during the existing unit outage, but restricting the outage to lower risk, late spring to early fall periods is October 2013, with a roughly six month outage.
    b. With a nearly new 2 x 5 MW GT leased unit required during an existing unit outage is July 2013 with the existing unit on outage about five months.
    c. With shorter duration engineering and procurement times for BOP, fuel system and electrical systems, the in-service can theoretically be advance two to three months, but outage scheduling would likely mitigate this.

    Note: Using leased parts during outage, or procuring used parts and refurbishing them, has no significant positive impact.
8. The capital cost for refurbishing the existing unit is between $4.5 and $5 million, depending on the amount of additional work found during refurbishment. If leasing a replacement 2 x 5 MW unit is required to avoid any outage, then the total capital cost would be between $9.5 and $10.0 million, depending on the market price and availability of portable/mobile equipment. There is some opportunity to slightly reduce costs if used parts for the unit, and in particular the power turbine disk, are available.

5.2 New and Nearly-New 2 x 5 MW Portable/Transportable Gas Turbine Generator Units

1. The two 5 MW transportable gas turbine units option is consistent with the requirements for black start power, the need to start a 3 MW power block (one boiler feed pump motor), and simplicity of managing the number of black start units in parallel.
2. The space requirements for the two 5 MW transportable gas turbine units (2 trailers each plus a common electrical building) cannot be accommodated in the existing GT area.
3. Space and civil requirements support the use of the existing well graded area behind the old security building as the best location.
4. Two new 5 MW transportable gas turbine units could be readily purchased, with a manufacturing time of about 12 months.
5. Two nearly new, used 5 MW transportable GT units may be possible to acquire to a shorter time. Their availability and cost are functions of the market place. The units may also have to be adapted to suit Holyrood conditions (motor and start voltages, applicable codes, design fuel combustors, NOx levels).
6. Emissions, particularly NOx emissions, will have to be addressed:
    iv) NOx emissions are dependent on the nitrogen content of the diesel fuel oil used.
    v) NOx emissions will be lower than those of the current GTG units, but being oil fuelled units will be challenged to meet Canadian Council of Ministers of the Environment (CCME gas turbine NOx emission guidelines
    vi) Newfoundland & Labrador environmental regulations require Best Available Control Technology (BACT), although the regulations have provisions relaxing BACT requirements for both economic impacts as well as flexibility of approval by the Minister considering roles.
        c. The current designs do not have special technology (i.e. Selective Catalytic Reduction (SCR)). Their costs, the impacts of the technology on black start readiness and reliability, and the costs and impacts of ammonia use and storage for SCR use, make their consideration unreasonable for the roles contemplated.

d. A project going forth will have to seek approval for an exemption from the BACT requirement, and will likely have restrictions placed on the unit such as a limit on the number of operating hours per year.

7. Five MW units are likely the upper limit of useful unit size for redeployment in support of transmission and distribution line maintenance support either post 2020 or periods up to 2020.
8. The earliest in-service date for procuring and installing 2 x 5 MW new gas turbine generators is May 2013. The earliest in-service date for procuring and installing 2 x 5 MW nearly new/used gas turbine generators is March 2013.
9. The capital cost for procuring and installing 2 x 5 MW new gas turbine generators is $13.3 million. The capital cost for procuring and installing 2 x 5 MW nearly new/used gas turbine generators is $11.5 million.

5.3 New and Nearly-New 5 x 2 MW Portable/Transportable Diesel Engine Generator Units

1. The five 2 MW transportable diesel engine generator units option is potentially consistent with the requirements for black start power, but:
   i) The units may have significant difficulty responding to a block load start of 3 MW power block (one boiler feed pump motor), and
   ii) Islanded synchronous operation during start-up of five units may be difficult to maintain and affect overall system capacity available and overall system start-up reliability. It will also likely require a more complex control system.
2. The space requirements for the five 2 MW transportable diesel engine generator units (5 trailers plus two electrical trailers plus a common electrical building) cannot be accommodated in the existing GT area.
   i) Space and civil requirements suggested that use of the existing well graded area behind the old security building was the best location.
   ii) Spacing requirements are increased by separation requirements between units
3. Five new 2 MW transportable diesel engine generator units could be readily purchased, with a manufacturing time of about 12 months.
4. Five nearly new, used 2 MW transportable diesel engine generator units may be possible to acquire to a shorter time. Their availability and cost are functions of the marketplace and the units may have to be adapted to suit Holyrood conditions (motor and start voltages, applicable codes, design fuel combustors, NOx levels).
5. Emissions, particularly NOx emissions, will have to be addressed:
   i) NOx emissions are dependent on the nitrogen content of the diesel fuel oil used.
   ii) NOx emissions, particularly for some used engines, may not be lower than those of the existing GT unit. They will have higher emission levels than the GT options.
   iii) Applicable diesel engine generator emission regulations in the US and Canada are in flux, with significantly more stringent requirements likely for units coming into service in the 2012 through 2015 period. Emergency power non-mobile (i.e. not on road or off-road units) will face significant but less stringent levels, but will have their operation limited to emergency use only (in effect similar to the restriction imposed on the existing GT).
   iv) Newfoundland & Labrador environmental regulations require BACT, although the regulations have provisions relaxing BACT requirements for both economic impacts as well as flexibility of approval by the Minister considering roles.

a. The current designs do not have special technology (i.e. Selective Catalytic Reduction (SCR)). Their costs, the impacts of the technology on black start readiness and reliability, and the costs and impacts of ammonia use and storage for SCR use, make their consideration unreasonable for the roles contemplated.
b. A project going forth will have to seek approval for an exemption from the BACT requirement, and will likely have restrictions placed on its role and likely a limit on the number of operating hours per year.

6. Two MW units are good candidates for redeployment in support of transmission and distribution line maintenance support either post 2020 or in possible periods up to 2020. They are typical of larger unit sizes deployed for that purpose now.
7. The earliest in-service date for procuring and installing 5 x 2 MW new diesel gensets is May 2013. The earliest in-service date for procuring and installing 5 x 2 MW nearly new/used diesel gensets is March 2013.
8. The capital cost for procuring and installing 5 x 2 MW new diesel gensets is $10.8 million. The capital cost for procuring and installing 5 x 2 MW nearly new/used diesel gensets is $9.6 million.

5.4 Overall Economics

Using the Assessment Basis,

1. The base capital cost comparison of the options is as follows:

BASE CAPITAL COST COMPARISON OF OPTIONS

Capital Cost Comparison
Capital cost estimate $1.000 Can 2011

Option Number	0	1	1A	2	2A
Option	Existing GT Refurb	New 2 x 5 MW GT	Used 2 x 5 MW GT	New 5 x 2 MW Diesel	Used 5 x 2 MW Diesel
GT/Diesel Cost	$2.950	$10.865	$9.234	$8.553	$7.453
Civil Works	$224	$131	$131	$131	$131
Electrical Works	$541	$759	$759	$801	$801
BOP Systems	$330	$129	$129	$129	$129
Existing Unit Demolition & Removal	$0	$7	$7	$7	$7
Sub-Total - Directs and Indirects	$4.046	$11.891	$10.260	$9.620	$8.520
Project Engineering	$324	$625	$544	$513	$458
Project Management	$283	$832	$718	$673	$596
Total	$4.652	$13.348	$11.522	$10.807	$9.575

+ Standby = Total	$4.825
+ New Rental Stdby = Total	$9.421

2. The life cycle cost comparison of the options in:
   - un-escalated non-discounted (not present worthed),
   - un-escalated discounted (present worthed),
   - escalated non-discounted (not present worthed), and
   - escalated discounted (present worthed) costs is as follows.

The existing unit refurbishment option costs include the lower cost standby option assuming that a replacement gas generator and power turbine are leased and installed while the existing units are sent out for refurbishment. This adds only about $170,000 to the base cost. The existing unit refurbishment option costs assuming the standby option using a complete, installed 2 x 5 MW nearly new GT leased option would add an additional $4.7 M. The options include a cost for differences in the likelihood of a failure occurring once during the period – an additional $10 million in 2016 for the existing GT and $3 to 4 million in 2016 for the 5 x 2 MW diesel options.

		Refurbished Unit, Use of Spare Gas Generator & Power Turbine					
		Capital Cost	OMA	Fuel	Sub-Total	Elect Value	Total
1	UNESCALATED	$14,825	$1,885	$1,408	$18,118	($1,648)	$16,470
2	UNESCALATED, DISCOUTED CASHFLOW	$11,454	$1,291	$959	$13,704	($1,122)	$12,582
3	ESCALATED CASHFLOW	$16,260	$2,159	$1,660	$20,079	($1,943)	$18,136
4	ESCALATED, DISCOUTED CASHFLOW	$11,521	$1,302	$992	$13,815	($1,161)	$12,654

		Option 1 New 2x5 MW GT					
		Capital Cost	OMA	Fuel	Sub-Total	Elect Value	Total
1	UNESCALATED	$6,348	$1,714	$1,237	$9,300	($1,648)	$7,652
2	UNESCALATED, DISCOUTED CASHFLOW	$8,766	$1,175	$842	$10,783	($1,122)	$9,661
3	ESCALATED CASHFLOW	$4,940	$1,963	$1,459	$8,362	($1,943)	$6,419
4	ESCALATED, DISCOUTED CASHFLOW	$8,731	$1,185	$871	$10,787	($1,161)	$9,626

	Option 1A Used 2x5 MW GT					
	Capital Cost	OMA	Fuel	Sub-Total	Elect Value	Total
1	$7,522	$1,714	$1,237	$10,473	($1,648)	$8,826
2	$8,632	$1,175	$842	$10,649	($1,122)	$9,527
3	$6,815	$1,963	$1,459	$10,236	($1,943)	$8,294
4	$8,618	$1,185	$871	$10,674	($1,161)	$9,513

		Option 2 New 5x2MW Diesel					
		Capital Cost	OMA	Fuel	Sub-Total	Elect Value	Total
1	UNESCALATED	$9,807	$323	$1,237	$11,366	($1,648)	$9,719
2	UNESCALATED, DISCOUTED CASHFLOW	$10,231	$220	$842	$11,293	($1,122)	$10,171
3	ESCALATED CASHFLOW	$9,358	$370	$1,459	$11,187	($1,943)	$9,244
4	ESCALATED, DISCOUTED CASHFLOW	$10,232	$222	$871	$11,325	($1,161)	$10,164

	Option 2A Used 5x2MW Diesel					
	Capital Cost	OMA	Fuel	Sub-Total	Elect Value	Total
1	$10,575	$323	$1,237	$12,134	($1,648)	$10,487
2	$10,128	$220	$842	$11,190	($1,122)	$10,068
3	$10,593	$370	$1,459	$12,422	($1,943)	$10,479
4	$10,143	$222	$871	$11,236	($1,161)	$10,075

6 RECOMMENDATIONS

1. The existing gas turbine generator should not be operated (started, operated, shut down), except in an emergency situation, and in such an emergency its operation should be observed remotely.
2. Using the Assessment Basis, the preferred option is Option 1, the 2 x 5 MW new GT installation.
3. Hydro should review the Assessment Basis and any impacts of changes in it as part of its internal decision-making process on the options.
4. Hydro should proceed with a preferred option as soon as practically possible, given that the likelihood of safely and successfully starting the existing GT unit in an emergency condition in its existing state is very poor and likely to decrease rapidly with time idle.
5. If Hydro internally chooses refurbishment of the existing GT generator as its preferred option, then the existing GT generator should undergo an extensive overhaul and repair program, including:

   i) Gas Turbine Unit

      a. Power turbine disk replacement (9 month manufacturing lead time);
      b. Power turbine damaged blades replacement (one or more) or significant repair;
      c. Gas generator blading cleaning and recoating;
      d. Inlet filter media replacement and inlet duct refurbishment (including cooling air duct to power turbine disk); and
      e. Exhaust stack replacement or extensive repairs

   ii) Gearbox lube oil system modification and refurbishment

      a. Seals replacement/modification;
      b. Venting system modifications to reduce lube oil pressure buildup;
      c. Lube oil pump system upgrade for start-ups; and
      d. Lube oil cooling fan replacement

   iii) Gearbox bearings refurbishment or replacement and/or unit re-alignment

   iv) GT Generator testing and refurbishment

      a. Unit generator electrical testing and possible rewind; and
      b. Unit generator exciter testing, and refurbishment/replacement as necessary

   v) GT electrical and controls system update to compliance with current standards and/or obsolescence replacement

      a. Unit AVR
      b. Unit MCC's

   vi) The GT and generator enclosure rooms' fire detection and suppression systems modifications to provide better coverage (as evidenced by the failure of the system to initially detect or suppress the gearbox lube oil fire in 2010).

   vii) GT fuel oil receiving, forwarding, and delivery system replacement in an enclosed shed.

   viii) GT generator building repairs:

      a. Major leaks in and around the gas turbine exhaust stack
      b. Minor leaks at generator ventilation stack
      c. Minor air leaks as a result of minor siding holes (corrosion)

   ix) Expansion of the electrical services room to allow for new electrical systems and current systems to be in compliance with current standards (i.e. space, separation distance for arc flash)

APPENDIX 1
GENERAL ARRANGEMENT DRAWING

APPENDIX 2
SEQUENCE OF EVENTS REPORT

APPENDIX 3
COST REPORT BY WORK ORDER/ASSET

APPENDIX 4
BUDGETARY INFORMATION - SOLAR TURBINES

APPENDIX 5
BUDGETARY INFORMATION - PETERSON POWER SYSTEMS

APPENDIX 6
BUDGETARY INFORMATION - ROLLS ROYCE

APPENDIX 7
EXISTING UNIT REFURBISHMENT CAPITAL COST DETAILS

Appendix 7

EXISTING UNIT REFURBISHMENT CAPITAL COST DETAILS

Base Existing GT Unit Refurbishment

Capital Cost
Existing Gas Turbine Generator and Major Auxiliaries.

Capital cost estimate $,000 Can 2011

Gas Turbine Generator & Auxiliaries		Material	Labour	Total	Range
	Gas Generator (Avon)	**$500**	**$0**	**$500**	**$400-$700**
	Power Turbine	**$534**	**$402**	**$936**	**$900-$1,100**
	Disassemble/reassemble	$0	$75	$75	
	New Disk	$331	$0	$331	
	Moving blades	$93	$0	$93	
	Rotor rehabilitation	$0	$282	$282	
	Inlet structure repairs	$10	$5	$15	
	Diaphragm section	$30	$10	$40	
	Bearings	$50	$20	$70	
	Exhaust volute	$20	$10	$30	
	Gearbox	**$125**	**$39**	**$164**	**$125-$200**
	Bearings	$80	$34	$114	
	Gearbox venting	$20	$5	$25	
	Contingency; 2nd opinion	$25	$0	$25	
	Generator and aux	**$950**	**$0**	**$950**	**$150-$1,200**
	Generator	$900	$0	$900	
	Exciter	$50	$0	$50	
	Inlet filter	**$120**	**$30**	**$150**	**$100-$1200**
	Exhaust stack	**$40**	**$10**	**$50**	**$30-$75**
	Commission unit		**$50**	**$50**	**$30-$75**
	Sub-Total	**$2,269**	**$531**	**$2,800**	**$2,400-$3,500**
	Contingency (excl Avon)	**$125**	**$25**	**$150**	**$100-$250**
	SUB-TOTAL -GTG & Auxiliaries	**$2,394**	**$556**	**$2,950**	**$2,500 - $3,750**

Site Civil & Structural Works - Rental Unit		Material	Labour	Total	Range
	Geotech Investigation - bearing capacity of soil	$0	$4	$4	$3-$10
	Pre-engineered shelter for elec. equipment	$40	$5	$45	$37-$55
	Concrete cable trench	$60	$10	$70	$60-$85
	Repair sections of roofing and siding that are corroded	$3	$2	$5	$3-$8
	Building extension shelter - for elec. equipment expansion	$30	$10	$40	$30-$50
	Building extension shelter - turbine fuel line mechanical equipment	$30	$10	$40	$30-$50
	Sub-Total	**$163**	**$41**	**$204**	**$175-$250**
10%	**Contingency**	**$16**	**$4**	**$20**	**$20-$25**
	TOTAL Civil Works	**$179**	**$45**	**$224**	**$195-$275**

Base Existing GT Unit Refurbishment (Contd)

Capital Cost
Existing Gas Turbine Generator and Major Auxiliaries.

Capital cost estimate $,000 Can 2011

Electrical Systems		Material	Labour	Total	Range
	Installation new 800A, 13.8 kV, 3ph, 60Hz Generator Main Breaker	$126.86	$12.80	$139.66	
	Removal of Existing Main Breaker		$1.60	$1.60	
	Installation of Cable Tray	$3.50	$1.25	$4.75	
	Installation of New Junction Box	$1.00	$0.48	$1.48	
	Removal of Existing Power Cables from Existing Breaker to Generator and T9 Transformer		$1.60	$1.60	
	Installation of New Power Cables from New Breaker to Generator (2 x 500kcmil) and T9 Transformer (2x500kcmil)	$50.00	$10.00	$60.00	
	Connection of Existing and Used CT, PT and Control Cables in New JB, and run the new CT, PT and Control Cables from new JB to new 13.8 kV Main Breaker (4 x 4c10, 1 x 4c12, 1 x 12c12).	$0.60	$1.60	$2.20	
	Installation of New 13.8kV Fusible Switch			$0.00	
	Removal of Existing 13.8 kV Fusible Switch		$1.60	$1.60	
	Install 3c2AWG, Teeck, 15kV, Cable from 112kVA Transformer to new 13.8kV Fusible Switch	$0.75	$0.30	$1.05	
	Remove Existing MCC		$8.00	$8.00	
	Install New MCC	$30.00	$8.00	$38.00	
	Install Cable Tray	$1.60	$0.90	$2.50	
	Install New Incoming and Feeder Cables for 600V Circuits			$0.00	
	3C12, Teck, 1000V, (Seven Circuits)	$1.26	$0.53	$1.79	
	3c10, Teck, 1000V, (One Circuit)	$0.24	$0.12	$0.36	
	3c6, Teck, 1000V, (Five Circuits)	$1.03	$0.35	$1.38	
	3c2, Teck, 1000V, (One Circuit)	$1.04	$0.20	$1.24	
	Install New 230V, 3ph, Auxiliary Distribution Panel	$0.65	$0.35	$1.00	
	Relocate 30kVA, 3ph, 550:230V Transformer and Connect to MCC and New 230V, 3ph, Auxiliary Distribution Panel		$3.00	$3.00	
	3c12, Teck, 1000V (One Circuit)	$0.18	$0.08	$0.26	
	3c10, Teck, 1000V, (Two Circuits)	$0.12	$0.06	$0.18	
	Install new 110VDC,. NEMA 1 Breaker, new NEMA1 Splitter, new DC Starters, and Existing 100A DC Distribution Panel	$31.00	$6.40	$37.40	
	Install New Feeders from Splitter to DC Starters and DC Distribution Panel			$0.00	
	3c12, Teck, 1000V (One Circuit)	$0.18	$0.08	$0.26	
	3c10, Teck, 1000V, (One Circuit)	$0.21	$0.12	$0.33	
	3c2, Teck 1000V (One Circuit)	$0.41	$0.14	$0.55	
	Remove Existing AVR/Start Rectifier		$1.60	$1.60	
	Install New AVR/Start Rectifier	$145.00	$20.00	$165.00	
	Miscellaneous Hardware, Tray and 4/0 Grounding	$7.50	$7.50	$15.00	
	Sub-Total	**$403**	**$89**	**$492**	**$450-$600**
10%	**Contingency**	**$40**	**$9**	**$49**	**$45-$60**
	TOTAL Electrical Works	**$443**	**$98**	**$541**	**$500-$650**

Base Existing GT Unit Refurbishment (Contd)

Capital Cost
Existing Gas Turbine Generator and Major Auxiliaries.

Capital cost estimate $,000 Can 2011

BOP Systems		Material	Labour	Total	Range
	Fuel enclosure (See Civil/Structural)				
	Fuel piping	$60	$15	$75	$60-$90
	Stack removal	$0	$75	$75	$25-$35
	Inergen system	$7	$3	$10	$7-$15
	Lube oil cooler	$130	$10	$140	$75-$175
	Sub-Total	**$197**	**$103**	**$300**	**$150-$320**
10%	**Contingency**	**$20**	**$10**	**$30**	
	TOTAL BOP	**$217**	**$113**	**$330**	**$180-$350**

TOTAL DIRECTS		Material	Labour	Total	Range
	Sub-Total	**$3,032**	**$764**	**$3,796**	**$3,200-$4670**
	Contingency	**$201**	**$48**	**$250**	
TOTAL DIRECTS		**$3,234**	**$812**	**$4,046**	**$3,500-$5,000**

Project Engineering Costs Mechanical		Material	Labour	Total	Range
	Project Engineering Costs		$324	$324	
	Project Management Costs		$283	$283	
	TOTAL Project Engineering & Management	**$0**	**$607**	**$607**	**$550-$700**

Total Without Transition Replacement	Material	Labour	Total	Range
	$3,234	**$1,419**	**$4,652**	**$4,000-$5,700**

Standby Option – Installing Leased Gas generator and Power Turbine Parts To Reduce Unit Outage

Capital Cost
Existing Gas Turbine Generator and Major Auxiliaries.

Capital cost estimate $,000 Can 2011

Total Without Transition Replacement	Material	Labour	Total	Range
	$3,234	**$1,419**	**$4,652**	**$4,000-$5,700**

Standby Unit Costs - Leased Parts		Material	Labour	Total	Range
(Substituting Gas Generator & PT During Refurb)					
	Gas Generator Rental and Use	$42	$10	$52	
	Power Turbine Rental & Use	$42	$11	$53	
	Gas Generator Delivery	$10	$10	$20	
	Power Turbine Delivery	$10	$10	$20	
	Sub-Total	**$103**	**$41**	**$144**	**$125-$200**
20%	**Contingency**	**$21**	**$8**	**$29**	
	TOTAL GTG Lease Parts	**$124**	**$49**	**$173**	**$150-$225**

Total Including Lease Parts	Material	Labour	Total	Range
	$3,357	**$1,468**	**$4,825**	**$4,150-$5,900**

Standby Option – Installing Leased Gas generator and Power Turbine Parts To Reduce Unit Outage

Standby Option –Leased Nearly new 2 x 5 MW GT To Reduce Unit Outage

Capital Cost
Existing Gas Turbine Generator and Major Auxiliaries.

Capital cost estimate $,000 Can 2011

Total Without Transition Replacement		Material	Labour	Total	Range
		$3,234	**$1,419**	**$4,652**	**$4,000-$5,700**

New GT Replacement During Outage		Material	Labour	Total	Range
	GT Lease - 2 x 5 MW				
	Rental ($/mo/GT=$105k for 2 GT and 10 months)	$2,100	$0	$2,100	
	Hourly operation charge (Assume $41/hr/GT x 1/mo x 2 Hrs)	$2	$0	$2	
	Delivery to Site (k$/GT)	$70		$70	
	Removal from site (k$/GT)	$70		$70	
	Mobilization (k$/GT)	$30		$30	
	Setup/Commissioning (k$/GT)		$220	$220	
	Breakdown/Demob (k$/GT)	$100		$100	
	Sub-Total	**$2,372**	**$220**	**$2,592**	
	Tax 10-15%	$237	$22	$259	
	Sub-Total	**$2,609**	**$242**	**$2,851**	**$2,500-$3,300**
10%	Contingency	$261	$24	$285	$250-$350
	TOTAL GT Lease	**$2,870**	**$266**	**$3,136**	**$2,750-$3,650**

Site Civil & Structural Works - Rental Unit		Material	Labour	Total	Range
	Geotech Investigation - bearing capacity of soil	$0	$4	$4	$3-$10
	Pre-engineered shelter for elec. equipment	$40	$5	$45	$37-$55
	Concrete cable trench	$60	$10	$70	$60-$85
	Sub-Total	**$100**	**$19**	**$119**	**$100-$150**
10%	**Contingency**	**$10**	**$2**	**$12**	**$10-$15**
	TOTAL Civil Works - rental Unit	**$110**	**$21**	**$131**	**$110-$165**

Electrical Systems - Rental Unit		Material	Labour	Total	Range
	3c500 kemil, Teck 15kV cable	$112.8	$10.0	$123	
	13.8kV isolating switchgear (3+1 fused switch)	$95.0	$10.0	$105	
	P&C/DCS interface	$55.0	$10.0	$65	
	10 x 3c12AWG, Teck, 1000V cable	$1.0	$2.3	$3	
	2 x 25c16AWG, Teck, 1000V cable	$8.5	$3.2	$12	
	4 x 4c12AWG, Teck, 1000V cable	$3.3	$6.3	$10	
	1 x 12C12AWG, Teck, 1000V cable	$2.2	$1.6	$4	
	3c2AWG, Teck, 15kV cable	$0.9	$0.3	$1	
	2 x 3c1/0, Teck, 1000V cable	$4.5	$1.1	$6	
	112kVA, 13.8kV:575V, 3ph, 60Hz transformer	$30.0	$3.0	$33	
	200A, 600V, 3ph, 60Hz automatic transfer switch	$5.3	$1.5	$7	
	200A, 600V, 3ph, 60Hz manual transfer switch	$2.0	$1.0	$3	
	MCC, 600A, 600V, 3ph, 3W	$30.0	$5.0	$35	
	30kVA, 575:120/280V, 3ph, 60Hz transformer	$1.0	$0.5	$2	
	129VDC distribution panel, motor starters and disconnects	$35.0	$6.5	$42	
	100A, 120/208V, 3ph, 60Hz distribution panel c/w breakers	$1.4	$0.4	$2	
	600V, battery charger, 129VDC output	$16.0	$3.2	$19	
	129VDC battery bank	$39.0	$7.5	$47	
	All interconnecting cabling	$16.0	$12.0	$28	
	Miscellaneous 4/0 ground wire, conducts trays and hardware	$16.0	$9.0	$25	
	Reconfiguration of DCS screens, conducts and existing system	$0.0	$25.0	$25	
	25kVA, 13.8kV, 3ph, 60Hz, zig-zag grounding transformer	$31.0	$2.0	$33	
	Commissioning	**$0.0**	**$63.0**	$63	
	Sub-Total	**$506**	**$184**	**$690**	**$650-$800**
10%	Contingency	$51	$18	$69	$65-$80
	TOTAL Electrical Works - Rental Unit	**$557**	**$203**	**$759**	**$725-$880**

Standby Option –Leased Nearly new 2 x 5 MW GT To Reduce Unit Outage (Contd)

Capital Cost
Existing Gas Turbine Generator and Major Auxiliaries.

Capital cost estimate $,000 Can 2011

BOP Systems - Rental Units		Material	Labour	Total	Range
	3" supply and return fuel line	$55	$22	$110	
	Sub-Total	**$55**	**$22**	**$110**	**$100-$125**
10%	Contingency	$6	$2	$11	$10-$13
	TOTAL BOP Rental Units - Rental Unit	**$61**	**$24**	**$121**	**$110-$138**

TOTAL DIRECTS - Rental Units		Material	Labour	Total	Range
	Sub-Total	**$3,270**	**$467**	**$3,770**	**$3,500-$4,000**
	Contingency	$327	$47	$377	$250-$500
TOTAL DIRECTS - Rental Units		**$3,597**	**$514**	**$4,147**	**$3,750-$4,500**

Project Engineering & Management Costs - Rental Units		Material	Labour	Total	Range
	Project Engineering Costs		$332	$332	
	Project Management Costs		$290	$290	
	TOTAL Project Engineering & Management - Rental	**$0**	**$622**	**$622**	**$500-$750**

	Material	Labour	Total	Range
Sub-Total Rental Units	**$3,597**	**$1,136**	**$4,769**	**$4,250-$5,550**

	Material	Labour	Total	Range
Total Including Rental Unit	**$6,830**	**$2,555**	**$9,421**	**$8,400-$11,500**

APPENDIX 8
DRAWINGS FROM HYDRO

The following drawings will be provided to CONSULTANT for information during the PROJECT:

Holyrood Generating Station - Stage 1 238 - 13 - 3000 – 003 Gas Turbine Unit Relaying and Metering 3 Line A.C. Schematic
Holyrood Generating Station 238 - 13 - 3000 – 007 Gas Turbine Unit - Cabinet No. 4 Control & Protection, Turbine &Generator Wiring Diagram (5 of 5)
Holyrood Generating Station 238 - 13 - 3000 – 007 Gas Turbine - Cabinet No. 3 Termination Assembly Layout and Wiring Diagram (Sheet 4A of 5)
Holyrood Generating Station 238 - 13 - 3000 – 007 Gas Turbine Unit - Cabinet No. 3 Control & Protection, Turbine &Generator (4 of 5)
Holyrood Generating Station 238 - 13 - 3000 – 007 Gas Turbine - Cabinet No. 2 Termination Assembly Layout and Wiring Diagram (Sheet 3A of 5)
Holyrood Generating Station 238 - 13 - 3000 – 007 Gas Turbine Unit - Cabinet No. 2 Control & Protection, Turbine & Generator Wiring Diagram (3 of 5)
Holyrood Generating Station 238 - 13 - 3000 – 007 Gas Turbine - Cabinet No. 1 Termination Assembly Layout and Wiring Diagram (Sheet 2A of 5)
Holyrood Generating Station 238 - 13 3000 – 007 Panel, Control & Protection, Turbine and Generator Cabinet No. 1 Wiring Diagram (Sheet 2 of 5)
Holyrood Generating Station 238 - 13 - 3000 – 007 Gas Turbine - Cabinet No. 5 DCS Layout and Wiring Diagram (Sheet 7)
Holyrood Generating Station 238 - 13 - 3000 – 008 Gas Turbine Unit Interconnections, Site Wiring Diagram (Sheet 1 of 3)
Holyrood Generating Station 238- 13 - 3000 – 010 Gas Turbine Unit Control & Protection Schematic Diagram (Sheet 1 of 6)
Holyrood Generating Station 238- 13- 3000-010 Gas Turbine Unit Control & Protection Schematic Diagram (Sheet 2 of 6)
Holyrood Generating Station 238 - 13 - 3000 – 010 Gas Turbine Unit Control & Protection Schematic Diagram (Sheet 3 of 6)
Holyrood Generating Station 238- 13- 3000-010 Gas Turbine Unit Control & Protection Schematic Diagram (Sheet 4 of 6)
Holyrood Generating Station 238 - 13- 3000-010 Gas Turbine Unit Control & Protection Schematic Diagram (Sheet 5 of 6)
Holyrood Generating Station 238 - 13 - 3000 – 010 Gas Turbine Unit Control & Protection Schematic Diagram (Sheet 6 of 6)
Holyrood Gas Turbine 238- 13- 2000- 016 Phasing Diagram
Holyrood Generating Station 238 - 13 - 2000 – 015 Gas Turbine Station Services Panel No. 2 Wiring Diagram
Holyrood Gas Turbine 238 - 13 - 2000 – 014 Exciter & A.V.R. Control Schematic Diagram
Holyrood Gas Turbine 238- 13-2000-013 Avon Start System Connection Diagram
Holyrood Generating Station - Gas Turbine 238 - 13- 2000- 012 575 Volt Motor Control
3 Phase AC. Schematic
Holyrood Generating Station - Gas Turbine 238 - 13- 2000-011 230 V, *30,* AC & 1 1OV DC Auxiliaries Control Schematic
Holyrood Generating Station - Gas Turbine 238 - 13 - 2000 – 010 575 V, *30,* Station Service Supplies and Auto Transfer Switch Control Schematic
NL and Labrador HYDRO 238 - 13- 2000- 017 Wiring Schedule (Sheets 1-28)
Holyrood Generating Station 238 - 13- 0310 -204 Station Service Units 1 & 2, Gas Turbine 4160V Breakers Auxiliary Relay Schematic (Control)
Holyrood Generating Station 238 - 08 - 2000 – 006 Gas Turbine Building Mechanical Equipment
Holyrood Thermal Plant 238 - 08 - 2000 – 007 Gas Turbine Building Modifications to Generator Cooling Air Exhaust Dampers
Holyrood Generating Station 238 - 08 - 2000 – 008 Gas Turbine Avon Vent Ducting

Holyrood Gas Turbine 238 - 08 - 2000 – 009 Compressed Air System Single Line Diagram
Holyrood Generating Station 238 - 13 - 3000 – 009 Gas Turbine Unit Junction Box, Assembly Arrangement of Air Piping 238 - 13- 6010- 015 For A.P.I. Gas Turbine (Sheet 1 of 3)
Holyrood Generating Station 238 - 13 - 3000 – 002 Gas Turbine Unit Panel, Control and Protection, Turbine & Generator
Holyrood Generating Station 238 - 13 3000 – 004 Gas Turbine Unit Junction Box, Pressure Switch, Assembly
Holyrood Generating Station 238 - 13 - 3000 – 005 Gas Turbine Unit Junction Box, Assembly
Holyrood Generating Station 238 - 13 - 3000 – 006 Gas Turbine Unit Junction Box, Assembly
Gas Turbine Generator Transformer Outline 238 - 13 - 6030 - 007R2 Halon 1301 Fire Extinguishing System Layout, 238 - 13- 3003- 001 Turbine & Generator Rooms
Holyrood Generating Station Fire Alarm/Halon Release 238 - 13 - 3003 – 002 Electrical Layout
Holyrood Generating Station Fire Alarm/Halon Release 238 - 13 - 3003 – 003 Control Panel Wiring Diagram
Holyrood Generating Station Holyrood Generating Station 238 - 13- 3000- 001 Gas Turbine Unit Interconnections, Site, Control System
Holyrood Thermal Plant 238 - 08 - 2000 – 001 Gas Turbine Building Outline of Exhaust Gas Stack
Holyrood Thermal Plant 238 - 08 - 2000 – 003 Gas Turbine Stack Support Steel (Original)
Holyrood Thermal Plant 238 - 08 - 2000 – 004 Gas Turbine Building Mechanical Equipment Mounting Details
Holyrood Generating Plant 238 - 04 - 2000 – 001 Proposed Building - Gas Turbine Floor Plan - (Electrical Equipment)
Holyrood Thermal Plant 238 - 08 - 2000 – 002 Gas Turbine Building Volute Exhaust Flange
Holyrood Generating Plant 238 - 04 - 2000 – 002 Proposed Building - Gas Turbine Elevations
Holyrood Thermal Plant 238 - 04 - 2000 – 003 Gas Turbine Building Roof Plan and Elevations
Holyrood Thermal Plant 238 - 04 - 2000 – 005 Gas Turbine Building Structural Steel Framing Plan
Holyrood Thermal Plant 238 - 04 - 2000 – 004 Gas Turbine Building Foundation Plan & Details
Holyrood Thermal Plant 238 - 04 - 2000 – 007 Gas Turbine Building Floor Plan and Section
Holyrood Thermal Plant 238 - 04 - 2000 – 008 Gas Turbine Building Miscellaneous Details
Holyrood Generating Station 238- 13- 0310-019 Gas Turbine Fuel Totalizer
Stack Cap (Snow Doors) 238 - 08 - 3001 – 001 Expansion Joint Fabric (Type C) Rectangular 238 - 08 - 3001 - 002
Holyrood Gas Turbine 238 - 13 - 2000 – 003 Single Line Diagram
Holyrood Thermal Plant 238 - 13 - 2000 – 004 Gas Turbine Building Grounding Layout
Holyrood Thermal Plant 238 - 13- 2000 – 005 Gas Turbine Building Conduit Layout & Details
Holyrood Gas Turbine 238 - 13 - 2000 – 001 Metering and Protection Single Line Diagram
Holyrood Gas Turbine 238 - 13 - 2000 – 006 Rehabilitation Project Schedule
Holyrood Thermal Plant 238 - 13 - 2000 – 007 Gas Turbine Building Lighting and Heating Layout
Holyrood Generating Station 238 - 13 - 2000 – 008 575 V, *30,* 230,1 iSV, 10 & 110 V D.C. Dist. PNL.'s 575V, 3 Phase Light Oil Transfer Pump
Holyrood Generating Station - Gas Turbine 238 - 13 - 2000 – 009 A.C. and D.C. Station Service Supplies Single Line
Holyrood Gas Turbine 238 - 13 - 6010 – 047 A.P.I. Governing & Control System Arrangement of Air Piping for A.P.I. Gas Turbine 238- 13- 6010-015 (Sheet 2 of 3)
Arrangement of Air Piping for A.P.I. Gas Turbine 238- 13-6010-015 (Sheet 3 of 3)

APPENDIX 9
BRADEN MANUFACTURING SITE SERVICE REPORT

APPENDIX 10
GREENRAY TURBINE SERVICE REPORT

APPENDIX 11
SIEMENS HRD CONDITION ASSESSMENT AND BUDGET PRICING

APPENDIX 12
ROLLS WOOD GROUP FIELD SERVICE REPORT