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AN APPLICATION TO THE
BOARD OF COMMISSIONERS OF PUBLIC UTILITIES

# 2010 CAPITAL BUDGET APPLICATION

## VOLUME II

August 2009

newfoundland labrador hydro
a nalcor energy company

A REPORT TO

THE BOARD OF COMMISSIONERS OF PUBLIC UTILITIES

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| REGISTERED PROFESSIONAL ENGINEER<br>PEG<br>ANDREA MACDONALD<br>Andrea MacDonald<br>SIGNATURE<br>July 31/09<br>DATE<br>NEWFOUNDLAND & LABRADOR | Electrical |
| | Mechanical |
| | Civil |
| | Protection & Control |
| | Transmission & Distribution |
| | Telecontrol |
| | System Planning |

# PLANT LIFE EXTENSION UPGRADES

## Hardwoods Gas Turbine

June 2009

newfoundland labrador hydro
a nalcor energy company

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# 1 INTRODUCTION

Newfoundland and Labrador Hydro (Hydro) owns and operates two 50 MW Gas Turbine plants as part of the Island Interconnected System. They are: the Stephenville Gas Turbine Plant, located in Stephenville; and the Hardwoods Gas Turbine Plant (Hardwoods), located in the west end of St. John's (see Figure 1). These facilities are primarily used to control the voltage of the Island Interconnected System. They are also used to produce power during peak and emergency periods. However, since Hardwoods and Stephenville are fueled by distillate (diesel), producing power at these facilities is more costly than producing power at the Holyrood Thermal Generating Station.

**Figure 1: Hardwoods Gas Turbine Plant**

Hardwoods is predominantly used to level out voltage fluctuations on the Island Interconnected System. Voltage fluctuations are undesirable and result from changes in the supply and demand of electricity. Using a process known as synchronous condensing, the system voltage is corrected and the proper voltage levels are maintained. Synchronous condensing stabilizes the voltage of the system. During synchronous condensing, the voltage drop is limited to no more than five percent below the nominal operating levels of 230, 138, or 66 kV.

Hardwoods has been in service since 1977 and will remain in service even in the event of an infeed from the Lower Churchill. This facility is ageing and has experienced equipment failures in recent years. For instance, the inverter failed in 2006 and the Human Machine Interface (HMI) failed in 2007. As well, various components installed at this facility are obsolete. This facility requires refurbishment work to maintain its operational reliability until its planned retirement in the mid 2020's.

In 2007, an engineering consulting company, Stantec Inc. (Stantec), completed a condition assessment and life cycle cost analysis study of the Hardwoods and Stephenville Gas Turbine Plants. Hydro commissioned the study to determine the best course of action to achieve a high degree of operating reliability at least cost for the next 15 years for both sites. Major equipment such as gas turbine engines, power turbines and power generators (also called alternators), as well as auxiliary systems such as lubricating oil systems, fuel systems, electrical systems and control systems were assessed during the study. Structures such as buildings, equipment enclosures, and exhaust stacks were also assessed. The consultant's final report, known as the Stantec Report, provides a comprehensive description of the required site refurbishments to ensure operational reliability for the next 15 years. The Stantec Report is over 600 pages in length and extracts have been presented herein rather than the entire document.

In 2009, Hydro initiated a four-year refurbishment program to implement the recommendations for Hardwoods put forth in the Stantec Report (see Appendix B). In 2012, Hydro plans to initiate a three-year program to implement Stantec's recommendations for the Stephenville Gas Turbine Plant.

# 2 PROJECT DESCRIPTION

This project is to complete work scheduled for years two, three and four of a four-year upgrade program of Hardwoods. The program will include refurbishment of the following equipment and systems:

- Gas Turbine Engines / Power Turbine Equipment;
- Inlet Air Systems End A and End B;
- Exhaust Stacks End A and End B;
- Glycol Cooler for Main Lube Oil;
- Gas Generator / Power Turbine Enclosures End A and End B;
- Alternator and Excitation System;
- Alternator Enclosure;
- Fuel Oil Storage System;
- Electrical Systems;
- Control and Instrumentation Systems; and
- Buildings.

The scope of work for the four-year program includes the implementation of all recommended refurbishments described in Stantec's final Condition Assessment and Life Cycle Cost Analysis report for Hardwoods. Additional items requiring refurbishment were identified after the completion of the Stantec Report. These items include grounding of the fuel storage system and modifications to fall arrest systems. These items are also included in the scope of work for this project. Refer to Appendix B for the detailed scope of work for the four-year program. Once all of the recommended work is completed, Hardwoods will be able to operate reliably for the next 15 years.

This project will complete the 2010 to 2012 scheduled work items. Further details are included in Appendix B and estimated costs are included in Appendix F.

# 3 EXISTING SYSTEM

The Hardwoods Gas Turbine Plant is located within the Hardwoods terminal station. This 50 MW facility consists of two identical 25 MW Rolls-Royce Olympus C gas turbine engines (see figure 2), Curtiss-Wright power turbines, and a Brush power generator. Each power turbine is connected to the power generator by a clutch. Auxiliary components, critical to the operation of the facility, include inlet air systems, fuel oil system, electrical system, and control and instrumentation systems. Buildings and structures on site include exhaust stacks, inlet air intakes, control building, fuel unloading building, fuel forwarding module, auxiliary module building, maintenance and parts storage building, high voltage switchgear building, and emergency backup diesel generator building.

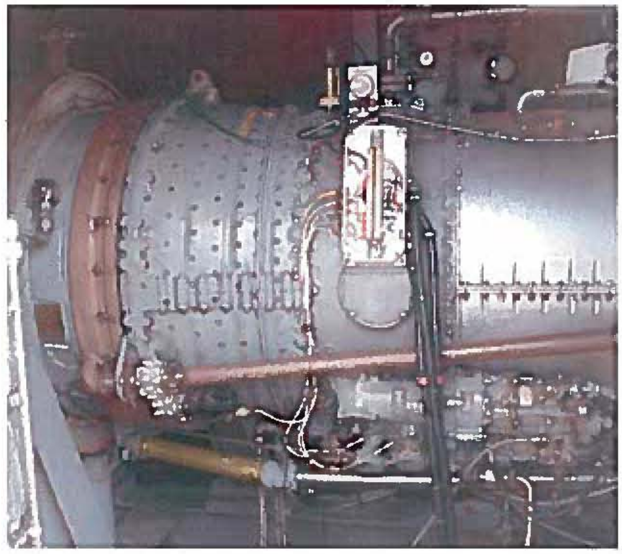

**Figure 2: Gas Turbine Engine**

It is stated in Stantec's Condition Assessment and Life Cycle Cost Analysis report for Hardwoods, that the gas turbine engines and power turbines show signs of operational wear and require remedial work (Appendix A: Executive Summary, page A-2). Further testing is required to determine the condition of the alternator. Auxiliary systems and structures were found to be in generally good condition, however, some refurbishment work is required.

The photo below (Figure 3), taken during an internal inspection on May 30, 2007, shows corrosion due to coating loss inside the End B gas turbine engine at Hardwoods.

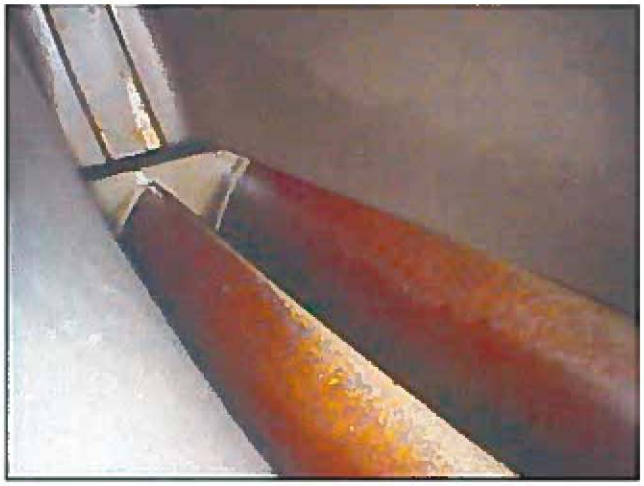

**Figure 3: Corrosion on End B Engine**

## 3.1 Age of Equipment or System

Hardwoods was placed in service in 1977. All major equipment, including the gas turbine engines, alternator, clutches and power turbines, is original.

## 3.2 Major Work and/or Upgrades

The End B gas turbine engine was overhauled in 1993 and both power turbines received casing replacements in 1988. Other upgrades at this facility include:

- exhaust stacks (1992);
- Distributed Control System (DCS) (1997);
- main breaker (1998);
- fire system replacement (2002);
- black start diesel generator (2005);
- fuel piping from the tank farm (2007);
- vibration system upgrade (planned for 2009); and
- repairs and site refurbishments (planned for 2009).

Appendix C contains a comprehensive listing of major work and upgrades that have taken place at Hardwoods since it was placed in service in 1977.

## 3.3 Anticipated Useful life

A gas turbine has an anticipated service life of 25 years. The upgrade will extend the life of the gas turbine plant by 15 years.

## 3.4 Maintenance History

The five-year maintenance history for Hardwoods is shown in Table 1.

**Table 1**
**Hardwoods Gas Turbine Plant Maintenance History**

| Year | Preventive Maintenance ($000) | Corrective Maintenance ($000) | Total Maintenance ($000) |
|---|---|---|---|
| 2008 | 26.3 | 269.0 | 295.3 |
| 2007 | 12.4 | 393.5 | 405.9 |
| 2006 | 5.6 | 441.9 | 447.5 |
| 2005 | 17.1 | 239.4 | 256.5 |
| 2004 | 14.9 | 258.8 | 273.7 |

## 3.5 Outage Statistics

Table 2 lists the 2004 to 2008 average Capability Factor, Utilization Forced Outage Probability (UFOP) and Failure Rate for Hardwoods compared to all of Hydro's gas turbine units and the latest Canadian Electrical Association (CEA) average (2002 to 2006).

**Table 2**
**Hardwoods Gas Turbine Five Year Average (2004-2008) All Causes**

| Unit | Capability Factor (%)[1] | UFOP (%)[2] | Failure Rate[3] |
|---|---|---|---|
| Hardwoods | 82.45 | 10.94 | 183.57 |
| All Hydro Gas Turbine Units | 87.02 | 11.39 | 42.12 |
| CEA (2002-2006) | 88.62 | 8.11 | 10.82 |

[1]Capability Factor is defined as unit available time. It is the ratio of the unit's available time to the total number of unit hours.

[2]UFOP is defined as the Utilization Forced Outage Probability. It is the probability that a generation unit will not be available when required. It is used to measure performance of standby units with low operating time such as gas turbines.

[3]Failure Rate is defined as the rate at which the generating unit encounters a forced outage. It is calculated by dividing the number of transitions from an operating state to a forced outage by the total operating time.

Hardwoods has an average failure rate over four times the average rate for all of Hydro's gas turbine units and almost 17 times the average rate posted for the CEA.

## 3.6 Industry Experience

The Hardwoods plant mainly operates as a synchronous condenser but produces electricity during peak and emergency times. This results in a very high number of starts and stops of the equipment annually. Frequent starts and stops of the equipment reduce its useful life far below the anticipated useful life of a base load plant.

Gas turbine engines, power turbines and clutches degrade over time. The degree of degradation increases as the operating hours increase and as the number of start/stop cycles increases. For gas turbine units that produce electricity during peak times, such as those at Hardwoods, thermal mechanical fatigue caused by start/stop cycles is the dominant limiter of life.

Stantec reports that 90 percent of all unscheduled shutdowns of gas turbine facilities are caused by faulty electrical and control components in auxiliary systems. In addition, since Hardwoods experiences many starts/stops in synchronous condensing and peak/emergency power generation modes, it is expected that the insulation on the alternator's windings will have a life of only 15 to 20 years as compared to 30 years for a power generation unit. An alternator problem may result in major unplanned outages.

## 3.7 Maintenance or Support Arrangements

Hydro personnel perform routine maintenance at Hardwoods on structures, auxiliary systems and parts of the major equipment. Any work involving removal of the gas turbine engine casing is performed by external contractors specializing in gas turbine repairs. Internal work on other major equipment is also performed by specialized contractors.

## 3.8 Vendor Recommendations

There are no vendor recommendations applicable to this project.

## 3.9 Availability of Replacement Parts

The model of gas turbine engine installed at Hardwoods is no longer manufactured, however, the engines will be supported by the manufacturer for the foreseeable future. Sourcing replacement parts for the gas turbine engines has not been an issue to date, however, the availability of spare parts is very limited worldwide. Original manufacturers still support other major components such as the alternator and clutches. It is difficult to acquire spare parts for the power turbine since the manufacturer is no longer in the power turbine business, therefore, spare parts for the power turbine would either need to be sourced on the second hand market, or reverse engineered and manufactured. Reverse engineering refers to a process of designing a new component by taking apart and analyzing an existing component.

Other pieces of equipment installed at Hardwoods are now obsolete or are no longer being supported by the manufacturer. These include ignition exciters, vibration monitoring system, speed governors/fuel valve assemblies, starter motor (no longer supported), power supply for the distributed control system and protection electro-mechanical relays. Spares are readily available for the speed governors, however, the technology is considered obsolete. Spares are limited for the electromechanical relays. Spare parts may be easily sourced for some auxiliary systems. However, replacement parts may not be exactly the same as the original components. Further system modifications may be required when replacing older parts. Control module cards are still available from the manufacturer and will be supported for at least ten years from the date they are discontinued.

## 3.10 Safety Performance

Stantec reported that kick plates are missing on maintenance walkway guard railings. Rusty stair treads or loose ladder rungs were also reported. These items will be upgraded during the 2009 refurbishment project. Installation of emergency stop buttons for the fuel pumps located inside the fuel forwarding module as well as grounding of the fuel tank will also take place in 2009.

## 3.11 Environmental Performance

There are no identified environmental performance issues related to Hardwoods.

## 3.12 Operating Regime

Hardwoods operates mainly as a synchronous condenser but also as a power generator. Appendix D contains information on the operating hours, number of start/stop cycles, power generation hours and synchronous condensing hours for the facility. It operates approximately 60 percent of the time, as a synchronous condenser.

The facility operates in power generation mode during peak usage times which is less than one percent of the time. This may occur anytime throughout the year but is most common from mid December to March. As well, this facility is placed in standby mode for emergency electricity generation during unplanned outages. The facility may also be placed in service to generate electricity during planned outages.

# 4 JUSTIFICATION

The operational reliability of Hardwoods is critical to ensure voltage regulation on the Island Interconnected System. As well, this facility is critical for the generation of peak and emergency power. Unless the reliability of this facility is improved (see Section 3.5), the Island Interconnected System may experience voltage fluctuations and power shortages. The major equipment installed at this facility is over 30 years old and has reached the end of its operating life. Plant refurbishment is now required.

The condition assessment and life cycle cost analysis report for Hardwoods, completed by Stantec in 2007, contains a description of recommended refurbishments. All site refurbishments recommended by Stantec will take place during the four-year refurbishment program. A number of additional items requiring refurbishment were noted by Hydro after the completion of the Stantec Report. Most of these additional items are justified on the basis that they are safety or environmental issues. The remaining additional items will serve to increase the operational reliability of the facility. It is important that these recommended refurbishments take place so that voltage on the Island Interconnected System will continue to be stable and peak and emergency power generation is available whenever it is needed.

## 4.1 Net Present Value

A net present value calculation of alternatives was completed by Stantec and is included in Section 8 of the Condition Assessment and Life Cycle Cost Analysis report. This section of the report is attached as Appendix E.

## 4.2 Levelized Cost of Energy

This facility generates electricity only during peak/emergency periods. Levelized cost of energy is not a factor in this project.

## 4.3 Cost Benefit Analysis

A cost benefit analysis has been completed and is attached as Appendix E. Each alternative solution was reviewed. It was determined that Option 1B, Hardwoods refurbishment with no mobile gas turbine rental allowance, was the least-cost option to achieve a high degree of reliability at Hardwoods for the next 15 years. Please refer to Section 4.10 for a list of alternative solutions.

## 4.4 Legislative or Regulatory Requirements

There are no legislative or regulatory requirements that justify this project.

## 4.5 Historical Information

In 2009, the first year of the four-year refurbishment program at Hardwoods, budgeted at a cost of $450,300, was initiated. The work to be completed in 2009 is on the following equipment and systems.

- Inlet Air Systems End A and End B;
- Exhaust Stacks End A and End B;
- Fuel Oil Storage System;
- Electrical Systems; and
- Control and Instrumentation Systems.

Additional work on the same equipment and systems will occur in 2010 to 2012. Further details are included in Appendix B. Refurbishment of the Glycol Cooler for Main Lube Oil System will not take place in 2009. The following items were prioritized higher and were completed in 2009.

- Replace underground sump drainage piping and sump pit cover; and
- Replace various pumps.

## 4.6 Forecast Customer Growth

This project is not required to accommodate customer growth.

## 4.7 Energy Efficiency Benefits

There are no energy efficiency benefits within the justification for this project.

## 4.8 Losses during Construction

There will be no losses during construction as the work will take place during a planned outage.

## 4.9 Status Quo

If this project is not completed, plant reliability will decrease and the frequency of unplanned outages will increase. This affects the voltage control on the power grid and the plant's ability to generate power during peak and emergency periods.

## 4.10 Alternatives

Table 3 contains six alternatives that Stantec presented to Hydro at the completion of the Condition Assessment and Life Cycle Cost Analysis Study. Hydro evaluated each alternative and determined that Option 1B, refurbish existing equipment with no mobile gas turbine rental allowance, was the preferred option.

**Table 3**
**Alternatives**

| Alternative | Description | Capital Cost Estimate[1] ($000) |
|---|---|---|
| 1A | Refurbish existing equipment – Hardwoods. Includes optional gas turbine rental allowance. | 7,814 |
| 1B | Refurbish existing equipment – Hardwoods. | 4,507 |
| 1 | New gas turbine engines and power turbines. Refurbish balance of equipment. | 26,420 |
| 2 | New alternator/exciter. Refurbish balance of equipment. | 7,163 |
| 3 | New gas turbine facility, including fuel forwarding module, controls and electrical auxiliary equipment. Dismantle existing gas turbines and use as spares. | 36,900 |
| 4 | Replace Hardwoods with new dynamic Volts-Amperes reactive (VAR) compensator. | 10,000 |

After evaluating each option, it was determined that option 1B achieves Hydro's objective of increasing reliability at least-cost for the next 15 years at Hardwoods. Stantec's study determined that there is no need to replace the complete facility, auxiliary systems and major components such as the gas turbine engines and turbines. Therefore, options 1, 2, and 3 were eliminated since all involve the replacement of major equipment. Option 4 was eliminated since dynamic VAR compensation only provides synchronous condensing and does not permit the plant to generate power. Option 1A was eliminated because Hydro has no requirement for a backup gas turbine engine while an existing gas turbine engine is being overhauled.

[1] The Capital Cost Estimate is based on Stantec's 2007 budget estimate and does not include escalation.

# 5 CONCLUSION

It is important for Hydro to have a reliable facility for synchronous condensing and peak/emergency power generation on the Avalon Peninsula. A four-year refurbishment program for Hardwoods was initiated to implement a list of recommendations contained in a condition assessment and life cycle cost analysis report of the facility that was completed in 2007 by Stantec. The results of the condition assessment and life cycle cost analysis were used to determine the best course of action to achieve a high degree of operating reliability at least cost for the next 15 years for Hardwoods.

## 5.1 Budget Estimate

The budget estimate for this three-year project is shown in Table 4.

**Table 4**
**Budget Estimate**

| **Project Cost:** *($ x1,000)* | **2010** | **2011** | **2012** | **Total** |
|---|---|---|---|---|
| **Material Supply** | 71.4 | 71.4 | 8.7 | 151.4 |
| **Labour** | 180.2 | 183.6 | 140.4 | 504.2 |
| **Consultant** | 0.0 | 0.0 | 0.0 | 0.0 |
| **Contract Work** | 807.9 | 796.9 | 2,482.5 | 4,087.3 |
| **Other Direct Costs** | 0.0 | 0.0 | 0.0 | 0.0 |
| **O/H, AFUDC & Escln.** | 139.0 | 166.5 | 471.8 | 777.3 |
| **Contingency** | 106.0 | 105.2 | 263.2 | 474.4 |
| **TOTAL** | **1,304.5** | **1,323.6** | **3,366.6** | **5,994.7** |

The budget estimate for this project, as well as the overall estimate for the entire four-year refurbishment program, is based on the construction cost estimate provided in the Stantec Report in 2007 (attached as Appendix F). The accuracy of Stantec's estimate is stated to be (+/-) 30 percent. Stantec's figures were escalated from 2007 to 2009 using appropriate multipliers. Additional costs were added to Stantec's estimate to cover engineering design and project management. Costs were also added for the additional refurbishment items noted by Hydro after the completion of the Stantec report. Table 5 contains the annual budget estimates for the four-year program.

**Table 5**
**Hardwoods Four-Year Refurbishment Budget**

| Year | Budget |
|---|---|
| 2009 | 450.3 |
| 2010 | 1,304.5 |
| 2011 | 1,323.6 |
| 2012 | 3,366.6 |
| **Total** | **6,445.0** |

## 5.2 Project Schedule

This project will be complete by 2012. This will mark the end the four-year refurbishment program for Hardwoods. Work measures to be completed each year are identified in Table 6 below.

**Table 6**
**Work Schedule**

| Activity | Year |
|---|---|
| Refurbish End B gas turbine equipment.<br>Site retrofits and upgrades. | 2010 |
| Refurbish End A gas turbine equipment.<br>Site retrofits and upgrades. | 2011 |
| Refurbish generator and exciter<br>Site retrofits and upgrades. | 2012 |

# APPENDIX A

## Extract (Executive Summary) from Stantec Final Report Condition Assessment and Life Cycle Cost Analysis Hardwoods and Stephenville Gas Turbine Facilities

Stantec
**FINAL REPORT**
**CONDITION ASSESSMENT AND LIFE CYCLE COST ANALYSIS**
**HARDWOODS AND STEPHENVILLE GAS TURBINE FACILITIES**

## Executive Summary

Stantec (formerly Neill and Gunter) conducted a Condition Assessment and Life Cycle Cost Analysis Study of the Newfoundland and Labrador Hydro ("HYDRO") Hardwoods and Stephenville Gas Turbine Facilities over the period July through December 2007. The Gas Turbines at each site have been in service since the mid 1970's. The objective of the Study is to provide HYDRO with recommendations on the best course of action to achieve a high degree of operating reliability at each site, at least cost, for a further 15 years of operation.

During the Study period meetings were held with HYDRO officials, visits were made to each site and available HYDRO documentation was reviewed in order to assess the current condition of the equipment and structures at each site and determine the best course of action to allow a further 15 years of reliable service. The Gas Turbines at each site have operated over the years primarily as synchronous condensers providing MVAR support of system voltage. While the Gas Turbines can provide 50 MWs of emergency generation capacity, there has been very little generation provided by the units over the past 30 years. Refer to Report Section 2 for an overview of the Gas Turbine Facilities at each site.

The Gas Turbine Facilities consist of major equipment such as the gas generator engines, power turbines and alternator supported by balance-of-plant auxiliary systems such as the oil fuel supply system; lube oil system; electrical systems (switchgear; motor control centres, dc batteries); control & instrumentation systems (distributed control system; temperature and vibration monitoring equipment). Structures such as buildings, equipment enclosures and exhaust stacks comprise the balance of components that make up the Gas Turbine Facilities at each site.

The condition assessment portion of the Study found that the gas generator engines and power turbines at each site show signs of operational wear and will require remedial work to allow reliable operation over the next 15 years. Since HYDRO was unable to provide any historical electrical testing data or visual inspection information on the alternator at either site, it was not possible to assess the current condition of either alternator and determine the extent of remedial work required to allow reliable operation over the next 15 years. HYDRO will have to conduct, at some point, a thorough electrical testing and visual inspection of the alternator's stator and rotor in order to arrive at a decision as to whether refurbishment or replacement is required. The existing balance-of-plant system equipment, buildings and structures at each site are generally in good condition however there is some degree of minimal refurbishment work required in these systems. Refer to Report Section 5 (Hardwoods) and Section 6 (Stephenville) for details on the condition assessment of each Gas Turbine Facility.

A review of the Operator's Logs provided by HYDRO, particularly over the past 5 years of operation, revealed numerous failed starts and trips of the Gas Turbines at both sites resulting from sporadic mechanical and electrical issues associated with auxiliary equipment on the gas generators engines and alternator and in the balance-of-plant systems. These sporadic issues are deemed fixable with the proper allocation of time, resources and budget. Refer to Report Section 4 for details on these operational issues.

In response to the findings of the condition assessment portion of the Study, options studied to provide reliable operation over the next 15 years included: (i) the refurbishment of the existing equipment and structures at each site; (ii) the replacement of specific major equipment items (gas generator engines, power turbines and alternator) with new equipment as well as the refurbishment of balance-of-plant systems at one or both sites; (iii) the addition of a new gas turbine to replace one or both existing gas turbines and (iv) for HYDRO's consideration, the addition of a dynamic var compensator (D-VAR) to replace one or both gas turbines for system MVAR support only, the dominant operating mode of the Gas Turbines over the past 30 years. Refer to Report Section 7 for details on the costs and technical aspects of the Options considered.

The 15 year life cycle cost analysis study of each Option included capital costs for engineering, equipment supply and installation, as well as fuel, operational and maintenance costs at each site. The 15 year life cycle cost analysis of each Option was performed using HYDRO's Cost/Benefit Financial Analysis Model which uses the Cumulative Net Present Value (CPW) approach to perform economic analyses comparisons of alternatives. Refer to Report Section 8 for details on the life cycle cost analysis of the various life extension Options considered. The following Table provides a summary of the Options evaluated and the ranking and CPW of each Option.

**15 Year Life Extension Options**
**Cumulative Net Present Value (CPW)**

| Ranking | Option | CPW (2007 Cdn$) | |
|---|---|---|---|
| | | Sub-Case #1 | Sub-Case #2 |
| 1 | Option 4 – DVAR | $8,995,597 | $8,995,597 |
| 2 | Base Case 2B- Stephenville Refurbishment - No GT Rental | $9,548,569 | $24,996,028 |
| 3 | Base Case 1B- Hardwoods Refurbishment - No GT Rental | $11,467,914 | $26,930,650 |
| 4 | Base Case 2A- Stephenville Refurbishment - GT Rental | $13,842,768 | $27,711,405 |
| 5 | Base Case 1A- Hardwoods Refurbishment - GT Rental | $16,010,747 | $29,894,660 |
| 6 | Option 2 – New Alternator/Refurbish Engines & Turbines – GT Rental | $16,248,954 | $28,574,070 |
| 7 | Option 1 – New Engines & Turbines/Refurbish Alternator – GT Rental | $33,088,681 | $36,221,835 |
| 8 | Option 3 – Complete New GT Unit | $38,145,919 | $38,145,919 |

A decision on the role of the Hardwoods and Stephenville Gas Turbines in the HYDRO system beyond 2023 (the specified 15 years of further service) has not been determined by HYDRO at this time. The financial analysis results in the Table reflect two scenarios beyond 2023. The first scenario (Sub-Case 1) assumes further refurbishment work in 2023, whereas the second scenario (Sub-Case 2) assumes the equipment will generally be totally replaced in 2023 with new equipment. The two scenarios however do not affect the overall ranking of the Options.

While Option 4, the Dynamic VAR Compensator (D-VAR) addition at one site, is ranked 1 in the Options considered, primarily due to significantly reduced operations and maintenance costs going forward, the capital costs used in the life cycle cost analysis of this Option are at best ballpark estimates and can only be confirmed through a detailed study on the application of this technology at one or both sites. In this Option, a D-VAR would replace a gas turbine at one or both sites for MVAR system voltage support only. The question that HYDRO must address regarding this Option is whether backup emergency generating capability is absolutely required at either site going forward. If the answer is yes, this Option can be dismissed from further consideration. If the answer is no, then a more detailed study of this Option should be conducted with the involvement of the equipment supplier to confirm costs and technical details. It is Stantec's opinion that this Option would be competitive with the Base Case existing equipment refurbishment Options 1 and 2 for MVAR system voltage support only, should HYDRO decide to forego generation capability at either site. Refer to Report Section 7 for details on the application of D-VAR technology.

The Base Case Options (1A/1B – Hardwoods) and (2A/2B – Stephenville) rank 2, 3, 4 and 5 of the Options studied. These Options, involving the refurbishment of the existing equipment at each site, assume the alternator will have to be extensively refurbished off-site at a supplier's facilities, over an estimated 4 month period. As noted previously, HYDRO will have to conduct, at some point, a thorough electrical testing and visual inspection of the stator and rotor in order to arrive at a decision as to whether refurbishment or replacement is required. Base Cases 1A and 2A assume that HYDRO will rent a mobile gas turbine to cover the alternator refurbishment period, whereas Base Cases 1B and 2B assume that HYDRO will schedule an estimated 4 month outage at each site when the alternator is being refurbished. The decision on the use of a rental unit is HYDRO's.

Option 2, ranked 6 of the Options studied would only be considered if pending a thorough testing and visual inspection of the alternator, it is determined the alternator cannot be refurbished and replacement is necessary to allow reliable operation over the next 15 years.

Options 1 and 3 ranked 7 and 8 respectively, have high CPWs and are not be considered as Options to pursue.

The Stantec team is of the opinion that the existing equipment, particularly the gas generator engines, power turbines and alternator, as well as the balance-of-plant equipment and structures can be refurbished sufficiently to allow reliable operation over the next 15 years. It is recommended that Base Case Options 1 and 2 at each site be pursued with a decision required on whether a rental mobile gas turbine will be employed at each site. Since no information was available to assess the condition of the alternator, the decision on the extent of refurbishment work required on this equipment will not be known until a thorough electrical testing and visual inspection of the stator and rotor is conducted. At that time, HYDRO will have to make a decision as to whether refurbishment or replacement is required. If replacement is necessary at one site or the other, then Option 2 should be pursued.

# APPENDIX B

## Recommended Site Refurbishments for Hardwoods Gas Turbine Plant

**Recommended Site Refurbishments to**

**Hardwoods Gas Turbine Plant**

*Recommended by Stantec, 2007*

Gas Turbine Engines / Power Turbine Equipment

- Disassemble End A and End B gas turbine engines. Inspect and refurbish as required.
- Inspect End A and End B power turbines upon removal of gas turbine engines. Perform required repairs.
- Completely disassemble and inspect End A and End B clutches.
- Replace ignition igniters.
- Replace speed governors/fuel valve assemblies.

Inlet Air Systems (End A and End B)

- Sandblast interior surfaces and recoat surfaces and silencer.
- Clean exterior of surface corrosion and recoat.
- Clean filter enclosure and recoat.
- Repair seals and recoat plenum access doors.
- Clean and recoat air inlet screens on End B.
- Re-align inlet bellmouth assembly on End B.
- Replace access ladders and modify guardrails.

Exhaust Stacks (End A and End B)

- Replace light gauge cladding with heavy gauge cladding on exterior upper portion of stacks.
- Clean and recoat exterior lower portion of stacks.
- Repair cracks in exhaust stack access door openings, in inner liner and internal rolled edge.
- Replace snow doors.

- Replace access doors with hinged doors.
- Replace access ladders.

Glycol Cooler for Main Lube Oil

- Clean and recoat entire structure.

Gas Generator and Power Turbine Enclosures (End A and End B)

- Clean and recoat exterior surfaces.
- Clean, sandblast, and recoat interior surfaces.

Alternator and Excitation Systems

- Conduct electrical tests on alternator, as per consultant's recommendations.
- Remove rotor for complete inspection of rotor/stator/exciter/bearings.
- Carry out refurbishment work based on inspection results. This may include rewind of stator and rotor, rewind/refurbishment of exciter.
- Perform a trim balance on the rotor to address vibration issues.

Alternator Enclosure

- Clean and recoat exterior surface.
- Fuel Oil System.
- Clean and recoat exterior of fuel oil storage tank.
- Repair and recoat various access stairs and handrails.

Electrical Systems

- Replace alternator 13.8 kV circuit breaker.
- Modify 13.8 kV cabling.
- Repair bus duct leaks.
- Replace 125 Vdc battery charger.
- Replace electromechanical protection relays with digital relays.

- Replace 15 kV power cable supplying the 750 kVA Station Service Transformer.

Control and Instrumentation Systems

- Stock spare input module cards for DCS system.
- Replace DCS power supply.
- Replace obsolete vibration monitoring system.
- Replace obsolete vibration transducers with new accelerometers.
- Replace existing thermocouple terminal blocks with terminal blocks for thermocouple use.
- Install low level cut out switch in oil storage tank.
- Relocate on-engine junction boxes to an off-engine site to reduce affects of vibration and heat.

Buildings

- Control Building: Clean and recoat building and install new roof.
- Fuel Unloading Building: Replace roof, pave area near off-loading containment dyke, replace posts and guardrails.
- Fuel Forwarding Building: Clean and recoat roof, replace posts and guardrails.
- Auxiliary Module Building: Clean and recoat roof.
- Maintenance and Parts Building: Clean and recoat roof.
- High Voltage Switchgear Building: Clean and recoat exterior walls. Replace roof.

**Recommended Site Refurbishments to**

**Hardwoods Gas Turbine Plant**

*Additional Work Identified After Completion of Stantec Report*

- Grounding of fuel storage system.
    - Noted in the Stantec Report as requiring further assessment;
    - After an assessment of FM Global Property Loss Prevention Data Sheet 7-88 – Flammable Liquid Storage Tanks (March 2009), it was determined by Hydro that grounding is required because the fuel storage tank is installed on top of a liner and the associated piping is not known to be grounded.
        - FM Global Property Loss Prevention Data Sheet 7-88 (Section 2.5 Ignition Source Control) states: "Provide static grounding connections on tanks that are out of contact with the earth if piping is ungrounded or nonconductive".
- Replace underground sump drainage piping and sump pit cover.
    - Leaks were discovered in 2007, 2008, and 2009.
- Replace various pumps.
    - Stantec Report recommends purchasing spares;
    - Installing the spare pumps will increase operational reliability.
- Provide position monitoring capability for liquid fuel valves.
    - Existing liquid fuel valves are original from 1976;
    - Existing valves do not have any position feedback to the DCS;
    - Without position feedback, it is impossible to determine the actual position of the valve (i.e. full open, full closed, or partially open);
    - The installation of valves with position monitoring capability will assist operations staff in troubleshooting fuel flow problems on the gas turbines.
- Repair or replace motorized valve on main fuel line.
    - This electrically-actuated valve closes off the main supply of fuel to the plant

and is required to protect the environment;
    - Currently, this valve does not open fully after it is fully closed;
    - An assessment is required to determine the cause of failure of this valve.
        - Possible causes are incorrect valve programming or a failed valve actuator.
- Inspect MLO and glycol piping and replace if required.
    - Existing outdoor piping is over 30 years old;
    - Piping failure will cause a forced outage.
- Install emergency shutoff for fuel pumps in fuel forwarding module.
    - The fuel forwarding module is a confined space building;
    - In an emergency situation, the operator must leave this building to shut down the pumps;
    - This has been entered as a SWOP (#2008004790);
    - Emergency shutoff will increase safety of personnel working in the module by giving them the ability to immediately shut down the fuel pumps during an emergency.
- Replace junction boxes JB-7A and JB-7B.
    - Existing outdoor electrical junction boxes are not watertight.

# APPENDIX C

## Hardwoods Gas Turbine Plant - Major Upgrades

**Hardwoods Gas Turbine Plant**

**Major Upgrades**

***Civil Engineering Projects***

1996 – 1997: Tank Farm upgrades.

- One tank was completely removed.
- Remaining tank was cleaned, welds were repaired, and interior floor was painted.
- New dyke liner was installed throughout (Tank was lifted).
- Dykes were re-shaped.
- New dyke section was installed (to reduce size of containment area).
- New piping was installed within tank farm.

2000: Painted exterior of tanks.

***Electrical Engineering Projects***

Early 1990s: Rotor rewinding and other associated repairs.

1994: Brushless exciter vibration issues.

- In October of 1994 high frequency vibration signatures were observed on the exciter and 'B' end alternator bearing.
- 1995 – 1996: Governor repairs.
- During the 1994 outage very low ramp rates existed and problems were experienced with the governor. Repairs were made to the governor in 1995 and 1996. Governors were calibrated and droops were setup.

1998: Switchgear upgrades.

- Purchase and installation of new main breaker. This breaker will be rated at 3000 Amp with an interrupting capacity of 28 kA. The existing breaker will be assessed for use as a system spare to serve both the Stephenville and Hardwoods site.
- Post insulators and insulation coverings on the rigid bus bars will be replaced/upgraded sufficient to re-rate the switchgear to 15 kV class.

2005: Battery bank replacements.

- The 125V 900 amp-hour VRLA bank for Hardwoods was replaced in 2005.

***Mechanical Engineering Projects***

Mid 1980's: Snow door actuation was converted from electric to pneumatic.

1988: Fern Engineering modifications.

- Primarily replaced the casing on each of the 4 Curtiss Wright power turbines (Stephenville and Hardwoods) which were prone to cracking. Other smaller components were replaced as well. Approx. cost $4 million.

Early 1990's: Redesign of inlet air filtration system for gas engine and generator.

1992: Exhaust stack replacement.

- Existing interior silencer panel was reused.

1993: Hardwoods B engine serial # 202223 overhaul.

2002: Gas turbine and generator modules fire systems replacement (Inergen).

2003: Installed new core in Heat Exchanger for MLO system.

2004: Installed new expansion joints in stacks.

2005: Air conditioner, for gas turbine control room, replaced.

2005: New double walled fuel tank for diesel generator.

2005: Black start diesel generator replaced.

- This generator restores Hardwoods to operation without relying on external energy sources.

2005: New flow meter for gas turbine.

2005: Installed motorized valve fuel line by main tank.

2005: Fuel lines for gas turbine installed above ground between unit and the fuel forwarding pumphouse.

2006: Repairs to glycol housing.

2007: Both Air compressors have been replaced.

2007: Underground fuel piping replaced.

***Protection and Control Engineering Projects***

1997: Control system upgrade

- This entailed removing approximately 250 electromechanical relays and timers and replacing the controls with a distributed control system. The DCS included a PC-based operator interface. Commissioning of controls performed by ABB (ETSI).

2003: Thermocouple blocks replaced

Misc.:

- Terminal blocks in junction boxes located around the unit were replaced due to the condition of the original set.
- Snubbers (free-wheeling diodes) were replaced at Hardwoods. Some had shorted out a year ago. These were for noise reduction.

2005: Emergency backup diesel generating units installed.

- Diesel Generating Unit #572 including 600V control panel and backup battery charger installed in existing diesel building.
- The diesel unit is designed to start automatically with the loss of AC station service supply to the gas turbine unit and in turn supply power to the backup battery charger which ensures the integrity of the 125 Vdc supply to the gas turbine itself during its starting cycle.
- The diesel unit also provides a backup AC supply for one of the air compressors should the

stored air supply run low during attempted start(s) of the gas turbine unit.

2006: AVR Replacement

- The Brush BAVR was removed and a new ABB AVR was installed.

2006: Inverter replacement

- Inverter failed and was replaced.

2007: Human Machine Interface (HMI) replaced after Nov 2007 failure of computer.

# APPENDIX D

## Operational Data – 2004 to 2009
## Hardwoods Gas Turbine Plant

| Operational Data for Hardwoods Gas Turbine Plant | |
|---|---|
| **May 31, 2004 to May 31, 2009** | |
| | |
| Operating Hours | 536.4 |
| Available but not Operating Hours | 41026.67 |
| Forced Outage Hours | 430.43 |
| Maintenance Outage Hours | 177.35 |
| Planned Outage Hours | 1184.42 |
| Number of Forced Outages | 59 |
| Number of Unit Starts | 217 |

# APPENDIX E

## Extract (Section 8.0) from
## "Condition Assessment and Life Cycle Cost Analysis
## - Hardwoods and Stephenville Gas Turbine Facilities"
## Stantec, December 2007

Stantec

**FINAL REPORT**
**CONDITION ASSESSMENT AND LIFE CYCLE COST ANALYSIS**
**HARDWOODS AND STEPHENVILLE GAS TURBINE FACILITIES**
December 18, 2007

# 8.0 LIFE CYCLE COST ANALYSIS OF REFURBISHMENT OPTIONS

## 8.1 GENERAL

The primary focus of the life cycle cost analysis aspects of the study involves an economic evaluation of the costs associated with the Base Cases and the various Options outlined in Section 7.0 i.e. refurbishing the existing units, the replacement of existing equipment with new, as well as other economic opportunities for improvement. The 15 year life cycle analysis includes capital costs for equipment supply and installation as well as operational and maintenance costs at each site.

The life cycle cost analysis of each Gas Turbine option was performed by using Hydro's Cost/Benefit Financial Analysis Model. The HYDRO cost/benefit analysis template uses the Cumulative Net Present Value (CPW) approach to perform economic or financial analyses of alternatives as part of the justification of a project. For the purposes of this Study, the CPW approach compares the various options available for Hardwoods and Stephenville Gas Turbines to provide reliable operation for a further 15 years.

## 8.2 FINANCIAL MODEL INPUT DATA/CRITERIA/COSTS

In discussions with HYDRO, it was agreed that the future operational mode of the Gas Turbines at each site, on an annual basis, will reflect to a large degree its annual operation over the past 5 years in terms of MW and MVAR output, operational and maintenance budgets. In a series of emails throughout October 2007, HYDRO provided the following Financial Model Input information. A copy of the various emails is included in Appendix 11.

### 8.2.1 MWHRS AND MVAR OUTPUT

The MWhrs loadings forecast for each Gas Turbine for the next 15 years is a very variable number as dictated by changing power system operational conditions. It was recommended in an October 26, 2007 HYDRO email (Email No. 1) to use 1200 MWhrs annually for each of Hardwoods and Stephenville Gas Turbines. It is recognized this number could change significantly over the next 15 years.

A HYDRO email of November 2, 2007 (Email No. 2) provided daily MVAR loadings on each Gas Turbine over the period June 10, 2006 – November 1, 2007. The daily average for both Hardwoods and Stephenville was typically under 10 MVAR with occasional peaks up to 25 MVAR. It will be assumed that this MVAR mode of operation will continue for the next 15 years.

The synchronous condenser operating hours, over the past 5 years at each site, as advised in a HYDRO email of October 26, 2007 (Email No. 1), are as follows:

- Hardwoods – 15,512 hours or an average of 3102 hours annually
- Stephenville – 4,799 hours or an average of 960 hours annually

The average annual hours of synchronous condenser operation will be carried forward as the annual MVAR operating mode for the next 15 years.

### 8.2.2 Operations and Maintenance Budgets

HYDRO, in an email of October 24, 2007 (Email No. 3) provided the following information on Operations and Maintenance Budgets at Hardwoods and Stephenville over the period 2002 through 2006 with a forecast for 2007. These Budget costs exclude fuel costs.

**Table 7**
**Operational and Maintenance Costs**
**Hardwoods and Stephenville**
**(Excludes Fuel Costs)**

| Year | Hardwoods | Stephenville |
|---|---|---|
| 2002 | $178,000 | $83,000 |
| 2003 | $236,000 | $105,000 |
| 2004 | $114,000 | $175,000 |
| 2005 | $425,000 | $114,000 |
| 2006 | $486,000 | $355,000 |
| 2007 (Forecast) | $300,000 | $160,000 |
| | | |
| **5 Yr Ave (Excluding 2007)** | **$287,800** | **$166,400** |

The 5 year average will be carried forward, adjusted for inflation, as an annual operations and maintenance cost for the next 15 years.

### 8.2.3 Gas Turbine #2 Oil Fuel Price Forecast

HYDRO, in an email of October 11, 2007 (Email No. 4), provided a forecast of #2 Oil fuel prices per liter over the period 2008 through 2037. For the purposes of the options life cycle cost analysis exercise, the 15 year forecast costs between 2008 and 2023 will be used.

**Table 8**

**# 2 Oil Fuel Price Forecast (Cdn$/l)**

**2008 - 2023**

| Year | | Hardwoods | | Stephenville |
|---|---|---|---|---|
| | | | | |
| 2008 | | 0.624 | | 0.686 |
| 2009 | | 0.552 | | 0.613 |
| 2010 | | 0.557 | | 0.619 |
| 2011 | | 0.578 | | 0.640 |
| 2012 | | 0.606 | | 0.668 |
| 2013 | | 0.631 | | 0.694 |
| 2014 | | 0.666 | | 0.730 |
| 2015 | | 0.686 | | 0.752 |
| 2016 | | 0.721 | | 0.788 |
| 2017 | | 0.751 | | 0.820 |
| 2018 | | 0.786 | | 0.856 |
| 2019 | | 0.816 | | 0.888 |
| 2020 | | 0.847 | | 0.919 |
| 2021 | | 0.867 | | 0.941 |
| 2022 | | 0.882 | | 0.957 |
| 2023 | | 0.902 | | 0.979 |

These annual fuel forecasts will be carried forward to compute fuel costs at each site for the next 15 years.

### 8.2.4 Inflation and Escalation Forecast

HYDRO, in an email of October 26, 2007 (Email No. 5), provided a forecast of inflation and escalation for the period 2000 through 2027. The forecast, included in Appendix 11, provides forecasts for General Inflation, Electric Utility Construction Price Escalation (5 categories) and Operating and Maintenance Cost Escalation.

The figures for the period 2008 through 2023 will be used in the life cycle cost analysis of the various Gas Turbine options.

### 8.2.5 Fuel Consumption at Each Site

HYDRO, in an email of November 13, 2007 (Email No. 6) provided the following information on fuel consumption at Hardwoods and Stephenville over the period 2004 through 2007. The 2007 figures are for a partial year assumed to cover 9 months. The consumption numbers are as follows:

**Table 9**
**#2 Fuel Oil Consumption (litres)**
**Hardwoods and Stephenville**
**(2004 - 2007)**

| Year | Hardwoods | Stephenville |
|---|---|---|
| 2004 | 95,288 | 50,241 |
| 2005 | 433,380 | 147,566 |
| 2006 | 738,552 | 389,686 |
| *2007 (partial year)* | *262,691* | *204,485* |
| | | |
| 2007 (full year forecast) | 350,255 | 272,646 |
| **3 Yr Ave (Excluding 2004)** | **507,395** | **269,966** |

The 3 year average will be carried forward as an annual fuel consumption figure for the next 15 years.

## 8.3 SUMMARY OF GAS TURBINE FACILITY REFURBISHMENT CAPITAL COSTS

The following Table 10 is a summary of the capital costs of the Gas Turbine Facility refurbishments – Base Case and Options - presented in Section 7.0 of this Report, which will be the subject of the life cycle cost analysis exercise. As noted in the various Tables in Section 7.0, there are further costs, associated with a number of the options, primarily modifications to existing enclosures to accommodate new equipment that will require further detailed investigation by the new equipment suppliers.

**Table 10**

**Gas Turbine Facility Refurbishment Capital Costs**

**(2007 Costs)**

| Cost Analysis Alternatives | Description | Capital Costs (Cdn$) |
|---|---|---|
| | | |
| **Base Case** | | |
| 1A | Refurbish Existing Equipment - Hardwoods GT<br>Allowance for Temporary Gas Turbine Rental (1) | $4,506,880.00<br>3,307,500.00 |
| 1B | Refurbish Existing Equipment - Hardwoods GT<br>No allowance for Temporary Gas Turbine Rental | $4,506,880.00 |
| 2A | Refurbish Existing Equipment - Stephenville GT<br>Allowance for Temporary Gas Turbine Rental (1) | $4,538,883.00<br>3,307,500.00 |
| 2B | Refurbish Existing Equipment - Stephenville GT<br>No allowance for Temporary Gas Turbine Rental | $4,538,883.00 |
| | | |
| **Options** | | |
| 1 | New Engines & Power Turbines – Refurbish Balance of Equipment (2) – one site<br>Allowance for Temporary Gas Turbine Rental (1) | $26,419,761.00<br>3,307,500.00 |
| 2 | New Alternator / Exciter – Refurbish Balance of Equipment (2) – one site<br>Allowance for Temporary Gas Turbine Rental (1) | $7,163,381.00<br>3,307,500.00 |
| 3 | New Gas Turbine – Dismantle existing Gas Turbine and use as Spare Parts – one site | $36,900,000.00 |
| 4 | Dynamic Var Compensation – Ballpark estimate at this time as a more detailed study is required to define scope and costs | $10,000,000.00 |

Note (1): The Gas Turbine rental covers a period of 4 months at the site.

Note (2): There are further costs associated with these options, primarily modifications to existing enclosures to accommodate the new equipment, which will require further detailed investigation by the new equipment suppliers.

## 8.4 LIFE CYCLE COST ANALYSIS ASSUMPTIONS AND COMMENTARY

A life cycle cost analysis of each option was performed using Hydro's Cost/Benefit Financial Analysis Model. The following sub-sections provide an overview of the analysis, assumptions and other criteria. Commentary is provided on the financial analysis of each Gas Turbine Facility Option. A copy of the various Life Cycle Cost Analysis Model runs is included in Appendix 12.

For the purposes of this study, the following assumptions have been used throughout all of the options:

Initial project capital cost is incurred end of year 2008

- Annual costs (fuel and O&M) begin 2009
- Annual costs are escalated through 2023 using the default indices in the NLH
- financial analysis tool
- The average fuel consumption over the past three years has been used as the base
- case for projections of future fuel consumption at both Hardwoods and
- Stephenville sites
- The 2007 project capital costs provided in Section 7.0 have been escalated to 2008
- to determine the "Project In-Service Cost," using the built-in "Hydro and Thermal
- Plant Indices" escalation factors in the NLH financial analysis tool
- O&M costs have been assumed as 50% materials and 50% labour
- Cumulative net present values are expressed in January 2007 dollars

Each of the options described below were analyzed to determine the comparative cumulative net present value (CPW) over 15 years of operation. Note that two sub-cases were run for each scenario, in order to gauge the possible impact of future HYDRO maintenance requirements:

**Sub-Case #1:** Additional refurbishment costs are assumed to be required in 15 years, and are accounted for in the financial model as replacement costs occurring in 2023. Future refurbishment costs are adjusted to reflect the degree of work completed in 2008 for each option.

**Sub-Case #2:** It is assumed that equipment refurbished in 2008 will require replacement in 15 years. These costs are accounted for in the financial model as replacement costs occurring in 2023.

#### 8.4.1 Base Case 1A – Hardwoods Refurbishment with Mobile Gas Turbine Rental Allowance

This scenario considers refurbishment at the Hardwoods site, with an allowance included for 4 months of rental mobile equipment during the refurbishment period.

For projecting future annual costs, 100% of historical fuel consumption and 90% of historical O&M costs have been assumed. This is to reflect that fuel consumption is unlikely to change significantly following refurbishment, and that annual O&M costs are expected to modestly improve.

For Sub-Case #1, it is assumed that a complete refurbishment of the unit will again be required in 2023 at identical refurbishment costs as incurred in 2008 escalated forward to 2023. For Sub-Case #2, an allowance is made for complete replacement of the unit in 2023 with a new gas turbine. Future costs are escalated using the default value in the NLH model. Resulting replacement costs in 2023 dollars are $11.8 million and $55.6 million for Sub-Cases #1 and #2, respectively.

The estimated CPW of costs for this option is $16.0 million and $29.9 million for Sub-cases #1 and #2, respectively.

#### 8.4.2 Base Case 1B – Hardwoods Refurbishment with No Mobile Gas Turbine Rental Allowance

This option considers refurbishment at the Hardwoods site (i.e. identical to the Hardwoods base case), except that no allowance for rental equipment is included.

For projecting future annual costs, 100% of historical fuel consumption and 90% of historical O&M costs have been assumed. This is to reflect that fuel consumption is unlikely to change significantly following refurbishment, and that annual O&M costs are expected to modestly improve.

For Sub-Case #1, it is assumed that a complete refurbishment of the unit will again be required in 2023 at identical refurbishment costs as incurred in 2008 escalated forward to 2023. For Sub-Case #2, an allowance is made for complete replacement of the unit in 2023 with a new gas turbine. Future costs are escalated using the default value in the NLH model. Resulting replacement costs in 2023 dollars are $6.8 million and $55.6 million for Sub-Cases #1 and #2, respectively.

The estimated CPW of costs for this option is \$11.5 million and \$26.9 million for Sub-cases #1 and #2, respectively. The lower costs than Base Case 1A illustrate the financial impact of rental unit expenses during refurbishment.

#### 8.4.3 Base Case 2A – Stephenville Refurbishment with Mobile Gas Turbine Rental Allowance

This scenario is for refurbishment at the Stephenville site, with an allowance included for 4 months of rental mobile equipment during the refurbishment period.

For projecting future annual costs, 100% of historical fuel consumption and 90% of historical O&M costs have been assumed. This is to reflect that fuel consumption is unlikely to change significantly following refurbishment, and that annual O&M costs are expected to modestly improve.

For Sub-Case #1, it is assumed that a complete refurbishment of the unit will again be required in 2023 at identical refurbishment costs as incurred in 2008 escalated forward to 2023. For Sub- Case #2, an allowance is made for complete replacement of the unit in 2023 with a new gas turbine. Future costs are escalated using the default value in the NLH model. Resulting replacement costs in 2023 dollars are \$11.8 million and \$55.6 million for Sub-Cases #1 and #2, respectively.

The estimated CPW of costs for this option is \$13.8 million and \$27.7 million for Sub-cases #1 and #2, respectively. Note that while the Stephenville refurbishment capital costs are similar to Hardwoods, the CPW is considerably lower due to Stephenville's lower utilization and fuel costs.

#### 8.4.4 Base Case 2B – Stephenville Refurbishment with No Mobile Gas Turbine Rental Allowance

This option considers refurbishment at the Stephenville site (i.e. identical to the Stephenville base case), except that no allowance for rental equipment is included.

For projecting future annual costs, 100% of historical fuel consumption and 90% of historical O&M costs have been assumed. This is to reflect that fuel consumption is unlikely to change significantly following refurbishment, and that annual O&M costs are expected to modestly improve.

For Sub-Case #1, it is assumed that a complete refurbishment of the unit will again be required in 2023 at identical refurbishment costs as incurred in 2008 escalated forward to 2023. For Sub-Case #2, an allowance is made for complete replacement of the unit in 2023 with a new gas turbine.

Future costs are escalated using the default value in the NLH model. Resulting replacement costs in 2023 dollars are $6.8 million and $55.6 million for Sub-Cases #1 and #2, respectively.

The estimated CPW of costs for this option is $9.5 million and $25.0 million for Sub-cases #1 and #2, respectively. The lower costs than Base Case 2A illustrate the financial impact of rental unit expenses during refurbishment.

#### 8.4.5 Option No. 1 – Replacement of Engines and Power Turbines

This option is for replacement of the gas engines and power turbines, and refurbishment of the alternator and auxiliaries. The Hardwood site is assumed as the base case. An allowance for 4 months of rental mobile equipment during the refurbishment period is included.

For projecting future annual costs, 90% of historical fuel consumption and 75% of historical O&M costs have been assumed. This is to reflect that fuel consumption is expected to improve following installation of modern engines, and that less maintenance will be required on the new machines.

For Sub-Case #1, it is assumed that partial refurbishment/major maintenance of the unit will again be required in 2023. This is to account for the fact that the original alternator would still be in place at that time, and that the engines will have been operating for 15 years. A cost of $5.9 million in 2023 dollars is assumed, based on 50% of the complete 2008 refurbishment cost estimate. For Sub-Case #2, an allowance is made for complete replacement of the alternator in 2023 as well as other required balance-of-plant refurbishments similar to that work done in 2008. Future costs are escalated using the default value in the NLH model, for a total cost of $15.8 million in 2023 dollars.

The estimated CPW of costs for this option is $33.1 million and $36.2 million for Sub-cases #1 and #2, respectively. This is one of the highest cost options, due to the high costs of the engine replacement which are incurred early in the project's life.

#### 8.4.6 Option No. 2 – Replacement of Alternator and Exciter

This option considers replacement of the alternator, and refurbishment of the gas engines and power turbines. The Hardwood site is assumed as the base case. An allowance for 4 months of rental mobile equipment during the refurbishment period is included.

For projecting future annual costs, 100% of historical fuel consumption and 80% of historical O&M costs have been assumed. This is to reflect that fuel consumption is unlikely to change significantly following refurbishment, and that annual O&M costs will be improved by installation of the new alternator.

For Sub-Case #1, it is assumed that partial refurbishment/major maintenance of the unit will again be required in 2023. This is to account for the fact that the original engines would still be in place at that time, and that the alternator will have been operating for 15 years. A cost of $5.9 million in 2023 dollars is assumed, based on 50% of the complete 2008 refurbishment cost estimate. For Sub-Case #2, an allowance is made for complete replacement of the engines in 2023 as well as other required balance-of-plant refurbishments similar to that work done in 2008. Future costs are escalated using the default value in the NLH model, for a total cost of $44.8 million in 2023 dollars.

The estimated CPW of costs for this option is $16.2 million and $28.6 million for Sub-cases #1 and #2, respectively.

### 8.4.7 Option No. 3 - New Gas Turbine Facility

This option is for installation of a complete new gas turbine, including engine, alternator and auxiliaries. The Hardwoods site is assumed as the base case. No allowance is included for rental equipment, as it is assumed that the new unit would be installed while the old system was still operational.

For projecting future annual costs, 90% of historical fuel consumption and 70% of historical O&M costs have been assumed. This is to reflect that fuel consumption is expected to improve following installation of modern engines, and that less maintenance will be required on the new unit. A capital maintenance expense of $2.0 million in 2023 is allowed for both Sub-Cases.

The estimated CPW of costs for this option is $38.1 million for both Sub-cases #1 and #2. It is assumed that only routine major maintenance will be required in 2023.

### 8.4.8 Option No. 4 - Dynamic Var Compensation

Although this option requires additional investigation, a scenario was developed to gauge the potential of dynamic VAR compensation. No allowance is included for rental equipment, as it is assumed that the new equipment would be installed while the old system was still operational. For future annual costs, it is assumed that fuel consumption will be eliminated and O&M costs will be reduced to 10% of historical.

With these assumptions, the DVAR option appears very competitive with the refurbishment options. The CPW of this option is $9.0 million, placing it ahead of all the alternatives. Additional work is required to further develop the technical and financial aspects of this option; however, it is evident that it deserves additional consideration.

## 8.5 LIFE CYCLE COST ANALYSIS RESULTS AND RANKING OF OPTIONS

The results of the life cycle cost analysis are summarized below in Table 11. In general, the refurbishment options are the least cost alternatives, regardless of the capital expenditure that is assumed to be incurred in 15 years time.

**Table 11**
**CPW of Alternatives**

| Ranking | Option | CPW (2007 Cdn$) | |
|---|---|---|---|
| | | Sub-Case #1 | Sub-Case #2 |
| 1 | Option 4 – DVAR | $8,995,597 | $8,995,597 |
| 2 | Base Case 2B – Stephenville Refurbishment, No Rental Allowance | $9,548,569 | $24,996,028 |
| 3 | Base Case 1B – Hardwoods Refurbishment, No Rental Allowance | $11,467,914 | $26,930,650 |
| 4 | Base Case 2A – Stephenville Refurbishment, with Rental Allowance | $13,842,768 | $27,711,405 |
| 5 | Base Case 1A – Hardwoods Refurbishment with Rental Allowance | $16,010,747 | $29,894,660 |
| 6 | Option 2 – New Alternator/Refurbish Engines & Turbines | $16,248,954 | $28,574,070 |
| 7 | Option 1 – New Engines/Refurbish Alternator | $33,088,681 | $36,221,835 |
| 8 | Option 3 – Complete New GT Unit | $38,145,919 | $38,145,919 |

Figures 1 and 2 provide a graphical summary of the options for Sub-Case #1. Note that the annual operating costs of each alternative have a relatively minor impact on life cycle costs compared to the required capital expenditures. This is due primarily to the ongoing projected synchronous condenser mode of operation of the Facilities over the next 15 years. If generation at each site should increase significantly in the next 15 years, O&M costs will increase accordingly. The lower O&M and fuel savings expected for the options where major equipment replacements are completed in 2008 therefore do not outweigh the early capital expenditure.

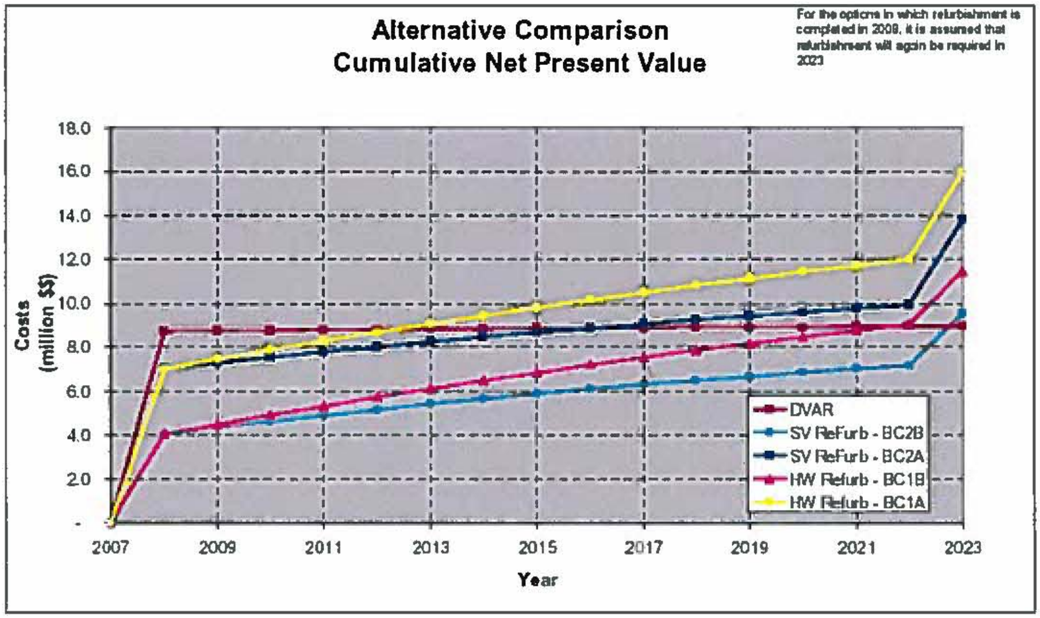


**Figure 1**
**Sub-Case #1 – Base Cases and DVAR Compensation**

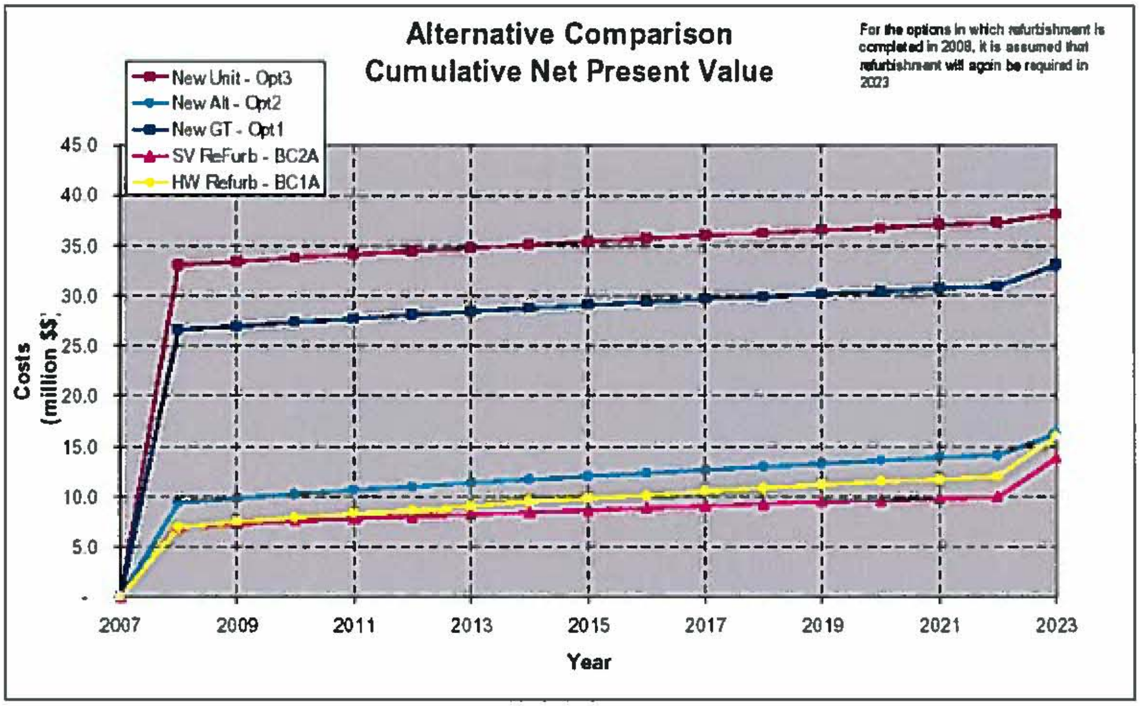


**Figure 2**
**Sub-Case #1 – Base Cases and Equipment Replacement Options**

# APPENDIX F

## Extract (Appendix 6) from "Condition Assessment and Life Cycle Cost Analysis - Hardwoods and Stephenville Gas Turbine Facilities" Stantec, December 2007.

## COST ESTIMATE SPREADSHEET No. 1

## HARDWOODS GAS TURBINE FACILITY

## REFURBISHMENT RECOMMENDATIONS

| | | |
|---|---|---|
| Newfoundland and Labrador Hydro | | |
| Stephenville and Hardwoods Gas Turbine Condition Assessment Study | | |
| NG Job No. 21061 | | |
| Rev 1 ----- 2007-12-14 | | |
| | COST ESTIMATE SPREADSHEET No. 1 | |
| | HARDWOODS GAS TURBINE REFURBISHMENT RECOMMENDATIONS | |
| Item | Hardwoods Recommendations | Cost Total |
| 1-- | **Gas Generators / Power Turbines Equipment** | |
| 1 | Engine A assembly be removed, disassembled to allow for detailed internal inspection with major refurbishments as required (Report para. 5.2.1) | |
| | o S&S Turbines Cost to refurbish and test engine assembly in BC | $515,000.00 |
| | o Cost to transport engine assembly to BC & back | 3,200.00 |
| | o Engine removal & reinstallation by S&S Turbines Technicians | 14,000.00 |
| 2 | Engine B assembly be removed, disassembled to allow for detailed internal inspection with major refurbishments as required (Report para. 5.2.1) | |
| | o S&S Turbines Cost to refurbish and test engine assembly in BC | $460,000.00 |
| | o Cost to transport engine assembly to BC & back | 3,200.00 |
| | o Engine removal & reinstallation by S&S Turbines Technicians | 14,000.00 |
| 3 | Inspect the Power Turbine assemblies A & B in detail upon removal of the Engines as noted in Items 1 & 2 to verify the mechanical integrity of the units. Inspect and refurbish the following: (Report para. 5.2.5) | $120,000.00 |
| | o Main line bearings inspection | |
| | o Remove turbine blades and perform metallurgical sampling to verify alloy composition and wear to the blade roots | |
| | o Remove turbine disks and perform metallurgical sampling to verify alloy composition and creep growth | |

| | | | |
|---|---|---|---|
| | o Apply anti-corrosion/thermal protection coatings to the turbine blades and nozzles | | |
| 4 | Completely disassemble and inspect the Power Turbine Clutches A & B. Determine and resolve the interference problem between the clutches and the proximity switches. (Report para. 5.2.6) | $13,000.00 | |
| 5 | Spare Item | | |
| 6 | Spare Item | | |
| 7 | It is recommended that HYDRO replace the following obsolete auxiliary components with components of current design. (Report para. 5.2.2) | | |
| | Quantity / Device | | |
| | o Replace Ignition Exciters | $24,000.00 | |
| | o Replace Speed Governors/fuel valve assemblies | $56,000.00 | |
| 8 | **Option:** | | |
| | S&S Turbines provides a rental engine for the period when an engine leaves site for refurbishment in BC until its return to site (estimated at 120 days per engine - assumes only one engine off-site at any time) | | |
| | o 120 days per engine x 2 = 240 days (8 months) | | |
| | o Fee for installation and removal = $14,000.00 | | |
| | o Monthly on-site rental fee = $2,450.00 x 8 = $19,600.00 | | |
| | o Fired hour charge = $42.00 per hour (Assume 60 hours in 8 months = $2,520.00) | | |
| | o Return transport from/to BC = $5,200.00 | | |
| | Total: | $41,320.00 | $1,263,720.00 |
| 2-- | **Inlet Air Systems A & B** | | |
| 9 | Interior of both Inlet Air Plenums A and B be sand blasted and the surface of the Inlet Air Plenums and the silencers re-coated. (Report para. 5.2.3) | $ 18,000 | |
| 10 | The exterior of both Inlet Air Structures be cleaned of surface corrosion | $ 24,000 | |

| | | | |
|---|---|---|---|
| | & flaking and re-coated. (Report para. 5.2.3) | | |
| 11 | Clean the surface corrosion inside the filter enclosure at the top of each Inlet Air Structure and re-coat. (Report para. 5.2.3) | $ 4,000 | |
| 12 | Replace the inner row of rubber sealing strips in Inlet Air Plenum A (Report para. 5.2.3) | $ 1,500 | |
| 13 | Complete following items regarding the access doors to both Air Plenum structures: (Report para. 5.2.3) | | |
| | o Sand blast and coat all areas corroded under the access doors | $ 700 | |
| | o Weld new plates inside the troughts | $ 600 | |
| | o Replace the weather stripping on the access doors | $ 1,000 | |
| | o Install a new drip cap over both access doors | | |
| 14 | Replace the ladders providing access to the platforms attached to each Inlet Air Structure and install kick plates on the ends of the platforms. (Report para 5.2.3) | $ 5,500 | |
| 15 | Clean the highly corroded screens on the Unit B Inlet Air Structure and re-coat. (Report para. 5.2.3) | $ 2,000 | |
| 16 | Re-align the inlet bellmouth assembly on Engine B (Report para. 5.2.3) | $5,000 | $ 62,300 |
| **3--** | **Exhaust Stacks A & B** | | |
| 17 | Replace the light gauge exterior cladding on the upper portion of each Exhaust Stack with a new corrogated metal cladding system. (Report para. 5.2.4) | $ 22,000 | |
| 18 | Clean the surface corrosion and coating failures on the heavy gauge cladding on the lower portion of each Exhaust Stack and re-coat. (Report para. 5.2.4) | $ 15,000 | |
| 19 | Repair cracks at two corners of the Exhaust Stack A access door opening in the inner liner, as well as cracks in the welds holding the interior mesh and insulation in place. (Report para. 5.2.4) | $ 800 | |

| | | | | |
|---|---|---|---|---|
| 20 | Repair cracks at two corners of the Exhaust Stack B access door opening in the inner liner, as well as cracks in the inner liner below the door opening and the internal rolled edge. (Report para. 5.2.4) | $ 1,200 | | |
| 21 | Replace the snow doors on each Exhaust Stack. (Report para. 5.2.4) | $ 34,000 | | |
| 22 | Replace existing access doors on the Exhaust Stacks with operable hinged doors with proper flashings and weather stripping In addition, modify the hatches below these doors, in the roof of the gas turbine enclosures, to prevent water leaks. (Report para. 5.2.4) | $ 16,500 | | |
| 23 | Replace the ladders providing access to the platforms on each Exhaust Stack. (Report para. 5.2.4) | $ 5,500 | | $ 95,000 |
| 4-- | **Glycol Cooler for Main Lube Oil** | | | |
| 24 | The entire Glycol Cooler steel structure and associated cladding be cleaned, prepared and re-coated within next 2 years. (Report para. 5.2.9) | $ 9,500 | | $ 9,500 |
| 5-- | **Gas Generator / Power Turbine Enclosures A & B** | | | |
| 25 | The exterior of both Gas Generator / Power Turbine Enclosures be cleaned of corrosion, prepared and re-coated within next 2 years. (Report para. 5.2.10) | $ 10,000 | | |
| 26 | The interior of both Gas Generator / Power Turbine Enclosures be cleaned, areas with corrosion sandblasted and re-coated. (Report para. 5.2.10) | $ 11,000 | | |
| 27 | Modify the existing man doors to both Power Turbine Modules to have inspection windows added. (Report para. 5.2.10) | $ 1,600 | | $ 22,600 |
| 6-- | **Alternator & Excitation System** | | | |
| 28 | Conduct Electrical Tests on the Alternator and Exciter while in its | $7,000.00 | | |

| | | | |
|---|---|---|---|
| | enclosure to determine condition as follows. (Report para. 5.3.3) | | |
| | o Alternator Stator EL-CID Test | | |
| | o Alternator Stator Polarization Index Test | | |
| | o Alternator Stator Partial Discharge Test | | |
| | o Alternator Rotor Megger Test - 500 vdc | | |
| | o Measure Alternator Rotor Winding Resistance | | |
| | o Rotating Exciter Stator and Rotor Megger Tests | | |
| | o Measure Rotating Exciter Stator and Rotor Winding Resistance | | |
| | | | |
| 29 | Remove & replace the Alternator from its Enclosure and remove the rotor | $50,000.00 | |
| | for a complete visual inspection of the stator / rotor / exciter. Inspections | | |
| | shall include: (Report para. 5.3.3) | | |
| | | | |
| | Stator Inspection to include but not limited to: | | |
| | o Loose or damaged Wedges | | |
| | o Loose or cracked or failed winding connections | | |
| | o Dusting, greasing and other signs of windings movement | | |
| | o Indications of arcing (hot spots) and damaged core laminations | | |
| | o Loose core bolts | | |
| | o Signs of corrosion, contamination and excessive dirt | | |
| | | | |
| | Rotor Inspection to include but not limited to: | | |
| | o Signs of physical damage | | |
| | o Loose or cracked or failed winding connectors | | |
| | o Slot wedge migration and possible contact with retaining rings | | |
| | o Signs of overheating | | |
| | o Loose rotor wedges | | |
| | o Dye penetrant examinations and magnetic particle tests on | | |
| | forgings; retaining rings and fan components to detect | | |
| | fatigue cracks. | | |
| | | | |
| | Bearings Inspection to include but not limited to: | | |
| | o Assess general condition of the bearings | | |
| | o Determine if the bearings require re-babbiting or machining. | | |
| | | | |
| | Carry out refurbishment work as required following | | |
| | completion of electrical tests (Item 27) and visual inspections | | |

| | | | | |
|---|---|---|---|---|
| | | (Item 28). Estimate includes: | | |
| | | o Rewind of stator at supplier's shop | $1,200,000.00 | |
| | | o Rewind of rotor c/w new end caps and overspeed testing at supplier's shop | $800,000.00 | |
| | | o Rewind /refurbishment of exciter | $25,000.00 | |
| | | o Transport costs to/from supplier's shop - assume UK | $30,000.00 | |
| | 30 | Perform a trim balance on the rotor to address the vibration issue observed physically and noted on the vibration monitoring system. There is a residual imbalance between the non-exciter and exciter of the alternator. (Report para. 5.2.7) | $10,000.00 | $2,122,000.00 |
| 7-- | | **Alternator Enclosure** | | |
| | 31 | The exterior of the Alternator Enclosure be cleaned to remove surface corrosion and flaking, prepared and re-coated within next 2 years. (Report para. 5.3.7) | $ 9,000 | |
| | 32 | Add inspection windows to the man doors in the alternator module for safety purposes. (Report para. 5.3.7) | $ 1,600 | $ 10,600 |
| 8-- | | **Fuel oil System** | | |
| | 33 | Clean, prepare and re-coat the storage tank exterior within the next 5 to 7 years. (Report para. 5.4.1) | $ 40,000 | |
| | 34 | Clean, prepare and re-coat the storage yank stairs and handrail within the next 2 to 3 years. (Report para. 5.4.1) | $ 4,000 | |
| | 35 | Replace two corrode stair treads on the storage tank stairs. (Report para. 5.4.1) | $ 750 | |
| | 36 | Install a kickplate at the handrail on the top of the storage tank. (Report para. 5.4.1) | $ 500 | $ 45,250 |

| | | | |
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| 9-- | **Electrical Systems** | | |
| 37 | Replace the alternator existing 13.8 kV circuit breaker with a new circuit breaker. (Report para. 5.5.1) | $60,000 | |
| 38 | Modify cabling in the 13.8 kV cable entrance cubicle as follows: | | |
| | o Short term - install dividers to separate the power cables from the control and instrumentation cables. | $3,500.00 | |
| | o Long term - Replace and install power cables in a separate compartment from the control and instrumentation cables. | $9,500 | |
| | (Report para. 5.5.1) | | |
| 39 | Repair bus duct leaks by either (i) applying rubberized asphalt roofing compound over the duct or (ii) cover the bus duct with cladding. (Report para. 5.5.3) | $6,000 | |
| 40 | Replace the existing 125 Vdc Battery Charger due to obsolence. (Report para. 5.5.5) | $17,000 | |
| 41 | Recommendation for HYDRO to prepare a replacement program and budget to replace over time the electro-mechanical generator protection relays with digital relays. (Report para. 5.5.6) | $21,000 | |
| 42 | Replace the 15 kV power cable supplying the 750 kVA Station Service | $6,100 | |
| | Transformer. (Report para. 5.5.7) | | $123,100 |
| 10-- | **Control & Instrumentation Systems** | | |
| 43 | Stock spares for input channel modules in the ELSAG Bailey INFI 90 DCS System. (Report para. 5.6.1) | $8,000 | |
| 44 | Replace the existing DCS System interface computer (PC) with a new | $4,500 | |
| | PC with the latest PCV and QNX software. (Report para. 5.6.1) | $8,000 | |
| 45 | Replace the existing obsolete DCS power supply system with a new power supply. (Report para. 5.6.1) | $24,000 | |

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|---|---|---|---|
| 46 | Due to hot and humid conditions in the Control Building, it is recommended that an air conditioning unit be installed in the area of the DCS equipment. (Report para. 5.6.1) | $1,000 | |
| 47 | Replace the obsolete vibration monitoring system. (Report para. 5.6.3) | $20,000 | |
| 48 | Replace the existing obsolete vibration transducers with new accelerometers. (Report para. 5.6.3) | | |
| 49 | Replace the existing terminal blocks for thermocouple terminations with terminal blocks designed for thermocouple use. (Report para. 5.6.4) | $600 | |
| 50 | Install a low level cut out switch in the oil storage tank as a backup to the level transmitter. (Report para. 5.6.9) | $2,500 | |
| 51 | Relocate the on-engine electrical junction boxes off the engines to isolate the terminations from vibration and heat. (Report para. 5.6.12) | $1,500 | $70,100 |
| 11– | **Buildings** | | |
| 52 | Control Building Refurbishments: (Report para. 5.7.1) | | |
| | o The exterior of the Building be cleaned of corrosion, prepared and re-coated within next 2 to 5 years. | $ 11,000 | |
| | o Install a new sloped roof over the existing flat roof for water tightness purposes. | $ 7,000 | |
| 53 | Fuel Unloading Building Refurbishments: (Report para. 5.7.2) | | |
| | o Replace the roof of the Building within next 2 years. | $ 5,000 | |
| | o Pave the area surrounding the concrete off-loading containment dyke to facilitate the clean up of any spills. | $ 1,200 | |
| | o The timber posts and guardrail protecting the concrete off-loading dyke and piping should be replaced. | $ 1,000 | |
| 54 | Fuel Forwarding Building Refurbishments: (Report para. 5.7.3) | | |
| | o Clean the roof, remove corrosion and repaint within 1 year. | $ 3,000 | |
| | o Clean the roof, remove corrosion and repaint within 1 year. | $ 1,500 | |

| | | | | |
|---|---|---|---|---|
| | | o The timber posts and guardrail protecting the Building should be replaced. | | |
| | 55 | Auxiliary Module Building Refurbishments: (Report para. 5.7.4) | $ 2,500 | |
| | | o Clean the roof, remove corrosion and repaint within 1 year. | | |
| | 56 | Maintenance and Parts Storage Building Refurbishments: (Report para. 5.7.5) | $ 5,000 | |
| | | o Clean the roof, remove corrosion and repaint within the next 2 years. | | |
| | 57 | High Voltage Switchgear Building Refurbishments: (Report para. 5.7.6) | $ 4,500 | |
| | | o Clean, remove surface corrosion and re-coat the exterior walls of the Building within the next 5 years. | $ 3,000 | |
| | | o Install a new roofing system such as a modified bitumen roofing membrane applied with hot asphalt directly over the existing roof to ensure water tightness. | | $ 44,700 |
| **12--** | | **Miscellaneous Work on Ongoing Operational Issues** | | |
| | 58 | A number of ongoing operational issues were identified by HYDRO personnel during the Study. It was not possible to provide detailed solutions to these issues during the Study due to schedule and budget constraints. It is recommended that HYDRO, as part of the overall refurbishment works, include money to address these issues. A figure of $250,000 is proposed. | $250,000.00 | $250,000.00 |
| | | **SUB-TOTAL:** | | $ 4,118,870 |
| | | **HYDRO labour & overhead costs for Items A - K at 8% of Sub-total:** | | $ 329,510 |
| **13--** | | **Spare Parts -- (Common To both Sites)** | | |
| | 59 | It is recommended that HYDRO stock the following spare parts to increase the overall reliability of the Gas Turbine: | | |
| | | **Quantity** — **Device** | | |
| | | -1- o Fuel Injection Nozzles (spare set) | $16,500.00 | |
| | | -1- o Spare Starter Assembly | $12,000.00 | |
| | | -1- o Spare Glycol Circulation Pump Set | $2,000.00 | |
| | | -1- o Spare 3-way Glycol Mixing Valve | $14,000 | |
| | | -1- o Spare Pressure Control Valve for Lube oil System | $6,000 | |
| | | -1- o Spare Control Valve for Fuel Oil System | $6,000 | |
| | | -1- o Install the facility for hook-up of a rental compressor. | $2,000 | $58,500.00 |
| | | **TOTAL:** | | **$ 4,506,880** |