Q. Reference: Newfoundland and Labrador Hydro's 2009 Capital Budget Application, Volume II, Tab 21, *Hardwoods Gas Turbine Plant Life Extension Upgrades.*

In 2007, Hydro engaged Stantec Inc., an engineering consultant, to complete a condition assessment and life cycle cost analysis study of the Hardwoods and Stephenville gas turbine plants. Please provide a copy of the final report(s) prepared by Stantec Inc. for Hydro.

A. Please see NP-NLH-013 Attachment 1, 2007 Stantec Condition Assessment Study Report.

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

Prepared for:

Newfoundland and Labrador Hydro
St. John's, NL

Stantec Job #: 21061
Ref. #: 2007-35410-OQ
December 18, 2007

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.

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APPENDICES

1.0 INTRODUCTION

1.1 GENERAL

Newfoundland and Labrador Hydro (“HYDRO”) issued a Request for Proposals (“RFP”) Contract Agreement 2007-35410-OQ on May 23, 2007 requesting Proposals for all work required to perform a condition assessment and life cycle analysis on gas turbines facilities located at Hardwoods, in the St. John’s area, and Stephenville, Newfoundland and Labrador. Neill and Gunter (Nova Scotia) Limited (“NG”) was awarded a Contract for this work on July 6, 2007. Following the award of the Contract, Neill and Gunter was acquired by Stantec Consulting Ltd. (“Stantec”) on October 19, 2007. The Contract was subsequently assigned to Stantec by HYDRO.

The purpose of the Study is to provide HYDRO with a comprehensive Report that can be used as the basis in deciding the best course of action to achieve a high degree of operating reliability, at least cost, for the next 15 years at each site.

This Final Report presents the findings of a Condition Assessment and Life Cycle Cost Analysis Study of the Hardwoods and Stephenville Gas Turbine Facilities carried out by Stantec over the period July through November 2007. The Report documents Stantec’s observations and comments from a site visit to Stephenville on July 17/18, 2007, a site visit to Hardwoods on August 21/22, 2007, a review of the documentation provided by HYDRO and discussions with HYDRO personnel during and following the site visits.

This Report is presented in ten sections. Section 1 outlines the scope of work, study methodology and information sources. Section 2 provides an overview of each Gas Turbine Facility and the equipment assessed. Section 3 presents a discussion on reliability, availability and maintainability (RAM) as it relates to the gas turbine and alternator. Section 4 reviews some of the operational issues affecting the performance of both Gas Turbines and the inspection and maintenance activities at each site. Section 5 provides a condition assessment of the equipment, buildings and structures at Hardwoods and Section 6 provides a similar assessment for the Stephenville site. Section 7 explores the options available for the 15 year life extension of both Gas Turbine Facilities. Section 8 presents a life cycle cost analysis of the various options. Section 9 provides the Study conclusions and recommendations. Section 10 relates to closure.

The Report presents a multi-disciplinary engineering condition assessment of the Gas Turbine Facilities and a life cycle cost analysis of refurbishing the existing units as compared to other options available to HYDRO for continued reliable operation at each site. The boundaries of the Study extend from the Fuel Unloading area up to the low voltage bushings of the Gas Turbine 13.8/66 kV step-up transformer at each site.

The focus of the technical aspects of the Study consisted of an evaluation of plant equipment, systems and components from an operational reliability, equipment availability and maintenance perspective in order to determine which components may require upgrade, replacement or repair due to equipment obsolescence, equipment ageing effects or maintenance practices in order to provide reliable operation over the next 15 years.

The focus of the life cycle cost analysis aspects of the study consisted of an economic evaluation of the costs associated with refurbishing the existing equipment, the replacement of existing equipment with new, as well as other economic opportunities for improvement. The 15 year life cycle analysis included capital costs for equipment supply and installation as well as maintenance and operational costs at each site. As agreed with HYDRO, the future operational mode of each unit on an annual basis will reflect its annual operation over the past 5 years.

An Interim Report on the Stephenville Gas Turbine Facility was issued on August 17, 2007. An Interim Report on the Hardwoods Gas Turbine Facility was issued on October 3, 2007. The Condition Assessment sections of each Interim Report have been incorporated in the Final Report. The Life Cycle Cost Analysis section of the Final Report is a new section not previously issued.

1.2 SCOPE OF WORK

The Condition Assessment and Life Cycle Cost Analysis of the Hardwoods and Stephenville Gas Turbine Facilities includes the following work scope as contained in the HYDRO Request for Proposal (RFP) Contract Agreement 2007-35410-OQ dated May 23, 2007.

- Perform a detailed assessment of the condition of the Hardwoods and Stephenville Gas Turbine Facilities. The assessment will identify potential problems in continuing to operate the Facilities as they presently exist for the next 15 years. Potential problems will include availability of service support by manufacturers. The study will recommend solutions with associated cost estimates for maintaining and running the Facilities as reliable generating units for that time period.

- Conduct Site investigations and inspections which will include where required opening and/or disassembly of major equipment components for internal inspection. The study shall focus on the Gas Turbine Facility in its entirety which shall include the fuel unloading system, storage and distribution system, fuel forwarding module, control module, air intake structures, gas turbines, power turbines, exhaust stacks, building enclosures, clutches, alternator, exciter, control systems, power systems, and auxiliary systems (i.e. compressed air, lube oil, glycol, etc.).

- Review information provided by HYDRO regarding significant upgrades or maintenance work performed on the Hardwoods and Stephenville Gas Turbine Facilities in the past for consideration in making assessments (i.e. gas turbine overhaul reports, alternator upgrades, etc.) on operating reliability over the next 15 years.

- Review information provided by HYDRO regarding current operating problems at the Hardwoods and Stephenville Gas Turbine Facilities for consideration in making assessments of operating reliability over the next 15 years.

- In addition the study will evaluate two other options for redeveloping the Hardwoods and Stephenville sites as follows:

Option 1: Replace the major equipment items and systems with new at one site. Existing infrastructures would be utilized where considered to be suitable for continued long term use. The components removed would be used as spares for the other site.

Option 2: Replace major equipment items and systems with new at both sites. Existing infrastructures would be utilized where considered to be suitable for continued long term use.

- Provide HYDRO with a comprehensive report that can be used as a basis in deciding the best course of action to achieve a high degree of operating reliability at least cost for the next 15 years at the Hardwoods and Stephenville Gas Turbine Facilities.

The Hardwoods and Stephenville Gas Turbine Facilities are located at terminal stations. The Study does not include equipment and structures that are part of the terminal station such as transformers, switchyard circuit breakers, etc. The Study also does not include the Gas Turbines SCADA remote control and monitoring equipment.

1.3 CONDITION ASSESSMENT AND LIFE CYCLE COST ANALYSIS METHODOLOGY

Stantec's approach or methodology in conducting the Gas Turbine Condition Assessment and Life Cycle Cost Analysis Study consisted of three phases.

Phase 1 involves -- (i) the visual inspection of the equipment, (ii) a review of operation and maintenance history, (iii) a review of data from regularly scheduled tests and inspections carried out on equipment and (iv) a review of equipment documentation – manuals, drawings, etc. Refer to Report Sections 4.0, 5.0 and 6.0 for details.

Phase 2 involves -- (i) an assessment of the data collected from Phase 1, (ii) compiling a list of recommended refurbishments to the existing equipment to allow for reliable operation over the next 15 years, (iii) source pricing on the refurbishments, (iv) prepare a performance specification and obtain pricing on the Study options ie replace the major equipment items and systems with new at one or both sites. Refer to Report Section 7.0 for details.

Phase 3 involves -- a life cycle cost analysis of (i) the refurbishment of the existing Gas Turbine Facilities and (ii) the Study options. This will require information from HYDRO on (i) historical maintenance and operations costs (ii) forecast of unit operation over next 15 years (iii) cost of capital, etc. Refer to Report Section 8.0 for details.

This methodology will provide HYDRO with a comprehensive report that can be used as a basis in deciding the best course of action to achieve a high degree of operating reliability at least cost for the next 15 years at the Hardwoods and Stephenville Gas Turbine Facilities.

1.4 INFORMATION SOURCES

Information for the Condition Assessment Study was sourced in a number of ways.

1.4.1 Meetings and Discussions with Newfoundland and Labrador Hydro

Kick-off Meetings were held concurrently with the visits to each site. A Stephenville Kick-off was held on July 17/18, 2007. A Hardwoods Kick-off was held at HYDRO offices in St. John's on August 21, 2007. A copy of the Minutes of each Meeting is included in Appendix 1. The Kick-off Meetings provided a good introduction for Stantec to the Hardwoods and Stephenville Gas Turbine Facility sites and various operational issues under consideration by HYDRO.

A list of HYDRO and Stantec personnel involved in the Study is included in Appendix 1.

1.4.2 Site Visits

A site visit followed the Kick-off Meetings. Stantec personnel, accompanied by HYDRO personnel, spent parts of July 17 and 18 at the Stephenville site and August 21 and 22 on the Hardwoods site inspecting the Gas Turbine Facility equipment and related civil, mechanical, electrical, instrumentation and control systems. Observations from the visit are documented in Sections 4.0, 5.0 and 6.0 of this Report.

1.4.3 Gas Turbine Plant Documentation

Stantec provided HYDRO with a List of Documentation required for review. The Final Report reflects documentation received as of November 15, 2007. Information requested for review included but was not limited to:

- Gas Turbine Facility Maintenance Records
- Gas Turbine Facility Operational Logs & Forced Outage Information
- Gas Turbine Facility Major Refurbishment/Overhaul Work Reports
- Equipment Inspection Reports including Oil Tanks (all equipment over past 10 years)
- Equipment Test Reports (all equipment over past 10 years)
- Gas Turbine O&M Manual
- Electrical Equipment O& M Manuals
- Control Equipment O&M Manuals
- Control System Architecture including communication links
- Programming software and platforms per control system
- Various Drawings
- List of major Spare Parts in inventory at Site
- List of existing parts/service providers for the major equipment
- Maintenance Plan and Schedule

HYDRO provided compact discs (CD's) on August 22 and September 20, 2007 containing available information on each site. A printout of the operational logs and the various maintenance Work Orders carried out at the Hardwoods and Stephenville sites was provided as well as various O & M Manuals and drawings. The area where little information was provided related to historical equipment test and inspection reports as well as reports on major refurbishment work carried out on the major Gas Turbine components – engines, power turbines and alternator. The lack of test and inspection information on the alternator in particular made the condition assessment of this equipment very difficult.

1.4.4 Equipment Supplier Contacts

Section 7.0 outlines a number of options considered for the reliable operation of the Hardwoods and Stephenville Gas Turbine facilities for a further 15 years. The options range from refurbishment of the existing Gas Turbine Facility equipment and structures to replacement of major components to replacement of the Gas Turbines themselves.

The following equipment suppliers were contacted for costing purposes:

- Brush Electrical Machines Ltd – Houston, USA – Mike Watkins
- MAN TURBO – Calgary, Alberta – Pierre Bovon
- Wood Group Generator Services – Louisiana – David Robinson
- Siemens Canada Limited – Dartmouth NS and Hamilton, ON – Bob Sheehan
- General Electric – Schenectady, NY – S. Wheeler

While several suppliers were responsive to our requests, many were not.

1.4.5 S&S Turbine Services Limited

Robin Sipe of S&S Turbine Services Limited of Fort St. John, British Columbia was a member of the Stantec team for the Condition Assessment Study. Mr. Sipe has extensive experience in the servicing and repair of Olympus C engines in particular. Mr. Sipe's experience was a valuable information source for both the Stantec team and HYDRO.

2.0 GAS TURBINE FACILITIES OVERVIEW

2.1 HARDWOODS GAS TURBINE FACILITY

The Hardwoods Gas Turbine Facility was placed in service in 1976 and operates as both a generator – peaking/emergency backup -- and a synchronous condenser, the latter being the dominant operating mode. The Gas Turbine, while averaging approximately 1000 running hours annually over its 31 years of service has experienced frequent start/stops, estimated to be in excess of 170 starts per year. A photograph of the Gas Turbine (Photo: HWD-001) is included in Appendix 13.

The Gas Turbine is located within a Terminal Station consisting of 66 kV and 230 kV bus work, circuit breakers, transformers and transmission lines. The Gas Turbine alternator output voltage of 13.8 kV is connected via enclosed bus duct to a circuit breaker located in a 13.8 kV switchgear assembly. A further run of enclosed 13.8 kV bus duct connects the circuit breaker to the LV terminals of a 13.8/66 kV, 45/60/75 MVA transformer. A System Operating Diagram and Single Line Diagram for the Hardwoods Site are included in Appendix 2.

The Facility consists of two Rolls Royce Olympus C, 25 MW Gas Generator Engines (A and B) fired on #2 Diesel Oil, each driving a Curtiss Wright Power Turbine equipped with a SSS size 208T clutch. Each Gas Generator Engine has an air intake structure and each power turbine has an exhaust stack. Gas Generator Engine B was overhauled in 1993. Gas Generator Engine A has never been overhauled since going into service in 1976. It is our understanding that both exhaust stacks at Hardwoods were replaced in 1992.

A 53 MW 13.8 kV Brush Alternator Frame BDAX8-280 is common to and driven by either or both, Power Turbines as required. The Alternator has a rotating exciter connected to the shaft. Generator air cooling is provided by fan blades on the alternator shaft that induces filtered outside air through the stator and rotor.

The lube oil system is common to each power turbine, clutch and the alternator. Lube oil cooling is provided by an external Glycol Cooler. The Glycol Cooler for the main lube oil system is located outdoors and a single glycol circulation pump and three-way temperature control valve are located in the Auxiliary Module Building dedicated for the main lube oil storage and pump facilities. Air compressors for starting air and process purposes are also located within the Auxiliary Module Building in an enclosed room. Air receiver tanks are located outside the building.

The fuel oil system consists of truck unloading facility pump sets located in a dedicated fuel oil unloading building at the storage tank area; one storage tank of 14,000 bbl (2,225,000L) nominal capacity and a piping system between the storage tank and fuel forwarding pump sets (AC and DC motor) located in a dedicated fuel forwarding building adjacent to the Gas Turbine.

Electrical equipment consists of a 13.8 kV switchgear assembly located in an outdoor enclosure; enclosed bus duct connecting the alternator to its circuit breaker and 13.8/66 kV step-up transformer. Motor control centres (AC and DC), protection and control devices, battery charger and inverter are located in the Control Building. The 125 V DC batteries are installed in a separate battery room within the Control Building.

An ELSAG Bailey INFI 90 DCS system installed in 1997 and located in the Control Building provides the local human machine interface (HMI) and the control and monitoring functions for the Facility. The Gas Turbine is also remotely started/stopped and monitored from the Energy Control Centre located in St. John's via a SCADA system.

From information provided by HYDRO in the Request for Proposals, the operational data on the Gas Turbine is as follows:

- Gas Generator A
  - 1200 running hours since installed in 1976
  - 2100 start/stops since installed
- Gas Generator B
  - 3935 running hours since year1993 overhaul
  - 3115 start/stops since year 1993 overhaul
- Alternator
  - 27,250 synchronous condenser mode running hours

2.2 STEPHENVILLE GAS TURBINE FACILITY

The Stephenville Gas Turbine Facility was placed in service in 1975 and is a sister unit to the Gas Turbine at Hardwoods. Like Hardwoods, the Stephenville Gas Turbine operates as both a generator – peaking/emergency backup -- and a synchronous condenser, the latter being the dominant operating mode. Based on information provided by HYDRO, the Gas Turbine, while having minimal running time, has experienced frequent start/stops, averaging in excess of 170 starts per year, over its 30 years of service. A photograph of the Gas Turbine (Photo: SVL-001) is included in Appendix 13.

While the alternators at Stephenville and Hardwoods are similar in terms of MW output and construction, they do have several major differences.

- The Stephenville alternator cooling system uses a 50/50 glycol-water mixture to absorb heat from the air circulating inside the alternator casing and discharges the heat to ambient air by means of an external heat exchanger complete with fan cooling. The Hardwoods alternator cooling does not use an external heat exchanger. The Hardwoods cooling system consists of intake filters and discharge louvers located on the alternator enclosure. The clean air is induced into the alternator by fan blades mounted on the alternator main shaft, and is rejected from the system via exhaust louvers.

- The Stephenville alternator rotor length is 1.64 meters longer than the rotor length at the Hardwoods site.

The Gas Turbine is located within a Terminal Station consisting of 66 kV and 230 kV bus work, circuit breakers, transformers and transmission lines. The Gas Turbine alternator output voltage of 13.8 kV is connected via enclosed bus duct to a circuit breaker located in a 13.8 kV switchgear assembly. A further run of enclosed 13.8 kV bus duct connects the circuit breaker to the LV terminals of a 13.8/66 kV, 45/60/75 MVA transformer. A System Operating Diagram for the Stephenville Terminal Station is included in Appendix 2.

The Facility consists of two Rolls Royce Olympus C, 25 MW Gas Generator Engines (A and B) fired on #2 Diesel Oil, each driving a Curtiss Wright Power Turbine equipped with a SSS size 208T clutch. Each Gas Generator Engine has an air intake structure and each power turbine has an exhaust stack. Gas Generator Engine B was overhauled in 2000. Gas Generator Engine A has never been overhauled since going into service in 1975. It is our understanding both exhaust stacks at Stephenville were replaced in 1992

A 53 MW 13.8 kV Brush Alternator Frame BDAX8-280 is common to and driven by each Power Turbine. The Alternator has a rotating exciter connected to the shaft. The lube oil system is common to each power turbine, clutch and the alternator. Lube oil cooling is provided by an external Glycol Cooler. Generator air cooling is provided by an internal air heat exchanger and an external Glycol Cooler. The two Glycol Coolers and pump sets are located outdoors.

The fuel oil system consists of a truck unloading facility; three storage tanks, each of 477,000 litre nominal capacity and fuel unloading and forwarding pump sets located in a Fuel Forwarding Building. Air compressors for starting air and process purposes are located within the Control Building in an enclosed room.

Electrical equipment consists of a 13.8 kV switchgear assembly located in an outdoor enclosure; enclosed bus duct connecting the alternator to its circuit breaker and 13.8/66 kV step-up transformer. Motor control centres (AC and DC), as well as 250 V and 125 V DC batteries, battery chargers and inverter are all located in the Control Building.

An ELSAG Bailey INFI 90 DCS system installed in 1999 and located in the Control Building provides the local human machine interface (HMI) and the control and monitoring functions for the Facility. The Gas Turbine is also remotely started/stopped and monitored from the Energy Control Centre located in St. John’s via a SCADA system.

From information provided by HYDRO in the Request for Proposals, the operational data on the Gas Turbine is as follows:

- Gas Generator A
  - 3883 running hours since installed in 1975
  - 3416 start/stops since installed
- Gas Generator B
  - 2015 running hours since year 2000 overhaul
  - 1770 start/stops since year 2000 overhaul
- Alternator
  - 3765 synchronous condenser mode running hours

2.3 GAS TURBINE FACILITY STUDY BOUNDARIES

This sub-section lists the Gas Turbine Plant equipment and structures at each site included within the boundaries of the Gas Turbine Condition Assessment and Life Cycle Cost Analysis Study. The Study boundaries encompass:

Gas Generator Engines and Subsystems

- Rolls Royce Olympus C Gas Generator Engines (2)
  - Fuel Piping
  - Woodward Governor
  - Gas Generator Engines Lube Oil System
  - Gas Generator Engines Bearings
  - Compressed Air Starting System
- Air Inlet Systems (2)
- Exhaust Stacks (2)
- Fuel Oil System
  - Oil Unloading
  - Oil Storage and Secondary Containment
  - Fuel Forwarding Equipment
  - Fuel Piping
- Gas Generator Engine and Power Turbine Enclosures (2)
- Fire Fighting Systems

Power Turbine, Alternator (Generator) and Subsystems

- Curtiss Wright Power Turbines (2)
- S.S.S. Power Turbine Clutches (2)
- Bearings
- Main Lube Oil System (common to the Power Turbines, Clutches and Alternator Bearings)
- Main Lube Oil Cooling System / Glycol Cooler
- Alternator Air Cooling System
- Alternator (Generator)
- Rotating Exciter
- Automatic Voltage Regulator (AVR)
- Alternator (Generator) Enclosure
- Fire Fighting System

Electrical Ancillaries

- 13.8 kV Switchgear (alternator breaker)
- Alternator Output Bus Duct
- Alternator protection relays
- Sync-check relay
- Motor Control Centres (AC & DC)
- Station DC supply (batteries and chargers)
- Inverter (AC supply for control systems)
- Emergency Backup Diesel Generator

Instrumentation and Control

- Bailey Control System
- SCADA interface (remote control and indication)
- Temperature monitoring system
- Vibration monitoring system
- Auxiliary Systems Instrumentation Devices
    - Fuel oil tanks
    - Fuel forwarding system
    - Compressed Air System
    - Glycol cooling system
    - Lube oil system

Buildings

- Gas Turbine Control Building (both sites)
- High Voltage Switchgear Building (both sites)
- Fuel Unloading Building (Hardwoods)
- Fuel Forwarding Building (Hardwoods)
- Auxiliary Module Building (Hardwoods)
- Maintenance and Parts Storage Building (Hardwoods)
- Fuel Unloading and Forwarding Building (Stephenville)
- Parts Storage Shed (Stephenville)
- Waste Oil Storage Shed (Stephenville)
- Emergency Backup Diesel Generator Building (both sites)

A condition assessment of the equipment and structures along with refurbishment recommendations is contained in Section 5.0 for Hardwoods and Section 6.0 for Stephenville.

3.0 RELIABILITY, AVAILABILITY, AND MAINTAINABILITY (RAM)

HYDRO's requirements for reliability, availability and maintainability (RAM) are major factors in the decision making process for the Options presented to ensure continued operation of the Facilities for the next 15 years. In this section of the Report, the factors that contribute to the RAM of the Facility are explained.

3.1 GAS TURBINE RAM PERSPECTIVE

3.1.1 Review of Performance Degradation Factors

The Hardwoods and Stephenville Gas Turbines mechanically consist of gas generator engines, power turbines and clutches (collectively the gas turbine unit). There are a number of factors that impact on the performance and reliability of this equipment. The basic factor is the mode of operation that can range from base load through to peaking and emergency stand-by. Most commonly, simple cycle gas turbine facilities such as those at the Hardwoods and Stephenville sites are used for peaking, emergency stand-by and synchronous condenser operation. However, installations designed and used regularly for synchronous condenser operations are a rarity.

The unit operating mode and external operating environment determine the working environment of the gas turbine parts. The unit operating conditions refer to the start/stop cycle, power load setting, and type of fuel. The start/stop cycle can be normal load start/stop, part load start/stop, emergency start/stop, fast load start/stop, synchronous condenser start/stop and trips. The following site factors impact upon the performance of the gas turbine:

- Ambient conditions and site elevation
- Inlet and exhaust loss
- Fuel
- Performance enhancement additions

The unusual operating requirements of these simple cycle gas turbine units suggest that their maintenance requirements will be different from the norms of the power generation industry. From the discussions and review of the Hardwoods and Stephenville maintenance procedures to date, it appears that formalized inspection plans have only been applied to these units in recent years. However, the facilities have given good service and are worthy of consideration for continued operation.

3.1.1.1 Gas Turbine Based Power Plant Ageing

Gas turbine engines, power turbines and clutches accumulate degradation as they accumulate operating hours, and the number of start/stop cycles. Power output and heat rates deteriorate and the failure rates increase in some sort of relationship that reflects the specifics of the site.

The hot parts of the engine are working under severe environmental conditions, namely, high flow rate, hot gases, and frequent temperature changes due to start-up and shut-down, and therefore they can have a relatively short lifespan. The hot gas path parts include combustion liners, end caps, fuel nozzle assemblies, crossfire tubes, transition pieces, turbine nozzles, turbine stationary shrouds, and turbine buckets. The damage accumulation of the buckets of a gas turbine firing at peak load will be faster than those firing at base load or part load, and therefore more significant ageing would result on a higher capacity factor plant.

3.1.1.2 Major Factors that Affect Equipment Life

The gas turbine's life is affected by many factors, and the mechanism of how these factors affect equipment life has to be well understood to produce effective maintenance planning and to project its life expectancy. The most important factors include starting cycle, power setting, and type of fuel. These factors have a direct impact on the life of critical gas turbine parts, and therefore they influence the maintenance interval.

> *Fuel type and quality*--- For distillate fuelled facilities like Hardwoods and Stephenville, the consideration is that the fuel is derived from crude oils that contain corrosive elements such as sodium, potassium, vanadium and lead. Distillate fuels generally release higher amounts of radiant thermal energy, which results in a subsequent reduction in combustion hardware life. The corrosive elements lead to accelerated hot corrosion of turbine nozzles and buckets. Distillate fuels do not generally contain high levels of corrosive elements, but trace quantities of contaminants can be present in these fuels, which lead to higher maintenance requirements than with natural gas fuel.
>
> *Load Setting*---Firing temperature co-relates with the load setting of the gas turbine unit. Under higher firing temperatures, the hot gas path parts are subjected to higher temperature hot gas, and this leads to high metal temperature, which reduces hot gas path components lives. However, a reduction in load does not necessarily mean an equivalent reduction in firing temperature, so there is always some degree of effect.
>
> *Cyclic effects*---The cyclic effects introduced during the frequent startup, operation, and shutdown of the gas turbine unit affect component life. There appears to be a requirement almost daily for these units to be started and run as Synchronous Condensers. Also, operating conditions other than the standard startup and shutdown sequence can potentially reduce the life of the hot gas path parts, rotors, and combustion parts. The starting cycle results in the most severe hot end thermal gradients experienced during normal engine operation. At ignition, the combustor exit temperature exceeds that during normal operation for a short time until the control system regulates the fuel and air flows to lower it. Therefore, the oxidation and corrosion experienced by the hot gas path is most severe at this time and will add to the engine ageing process. Frequent start/stops will further increase the ageing process.

3.1.1.3 The Accumulated Damage Mechanism

The causes of wear of hot gas path components of peaking plants due to cyclic duty application include thermal mechanical fatigue, high-cycle fatigue, rubs/wear, and foreign object damage. Another example is when the gas turbine experiences a trip rather than a normal base load shut down. This results in a more precipitous reduction in temperatures that promotes the development of cracks. Turbine trips (shutdown of the turbine) occur when the protective functions of the control system act as a result of detecting such events as: electrical protection trip, over speed, over temperature, high rotor vibration, fire, loss of flame, or loss of lube oil pressure.

The lengths of cracks that manifest in the hot gas parts are used as an indication of the safety of continued operation of the unit. If cracks appear on the rotating components (discs and blades), it is risky to continue operating the machine. Cracks on the stationary components can be tolerated provided they do not form a combination wherein a portion of material can be released into the gas stream. From this, it can be inferred that a scheduled frequency of borescope inspections should be in place for these units. The basis should be related to the number of starts together with the number of running hours. The precise formula that incorporates these parameters requires review of past operating experience and the results of inspections.

A certain limit for the crack length is set for a particular type of part, and a hot gas part whose crack length is beyond this limit is scheduled a repair or replacement. For peaking gas turbine units, thermal mechanical fatigue is the dominant limiter of life and understanding the interaction between thermal mechanical fatigue, creep, oxidation, and corrosion is necessary for estimating the overall life expectancy for gas turbines.

3.1.1.4 Performance Degradation

All types of turbo-machinery experience losses of performance with time. Even under normal operating conditions, with a good inlet air filtration system and using a clean fuel, the engine flow path components will become fouled, eroded, corroded, covered with rust scale, damaged, etc. The result will be degradation in engine performance, which will get progressively worse with increasing operating time. Thus, the gas turbine performance deteriorates as its operating hours accumulate, and the economic impact of engine performance degradation is significant. The majority of the power loss in a gas turbine is due to compressor degradation.

Gas turbine performance degradation can be classified as recoverable and non-recoverable losses. Recoverable losses are usually associated with compressor fouling and can be partially rectified by water washing. The non-recoverable losses would be due to degradation of the blades that would have to be re-conditioned or replaced to restore performance. Remember that performance degradation is a function of the operating mode, therefore the specific operating modes for these HYDRO units should be considered for performance degradation rate prediction and modeling.

Detection of the extent of the performance degradation is necessary before appropriate actions, such as online water wash or off line water wash, be taken. This infers data acquisition and assessment that would call for more instrumentation than exists on these units. Economic consideration is an important factor for determination of the optimal frequency of engine cleaning frequency. Some experts recommend that the compressor should be water washed when the estimated mass flow decrease reaches the 2 to 3% level. HYDRO could install instrumentation to monitor LP compressor efficiency. Once efficiency drops to a predetermined point, say 2%, a water wash request comes up as an operator alert. To incorporate this feature, five data points are required:

- Mass airflow (bellmouth depression reading)
- Inlet air temperature (RTD in bellmouth)
- Outlet air temperature (RTD or thermocouple in LP compressor outlet casing)
- Inlet pressure (piggybacked onto bellmouth depression)
- Outlet pressure (LP compressor discharge pressure)

3.1.1.5 Reliability Degradation

Operational risk is evaluated as the product of probability of system failure and the economic consequences of system failure. The gas turbine reliability is subject to degradation, and the degradation rate depends on the same factors as for performance degradation. However, it must be noted at the Hardwoods and Stephenville sites that the simultaneous forced outage of both gas generator engines and power turbines is a rarity, and the alternator has a very high reliability record. Industry indicates that 90% of all unscheduled shutdowns are caused by faulty electrical and control components in auxiliary systems.

The gas turbine unit is subject to increasing operational risk as its operating time accumulates. To reduce the risk, some of the parts need to be repaired or replaced when the accumulated damage reaches limits that are machine design specific. Therefore, to assess the operational risk of failure of a gas turbine unit and to schedule a reasonable maintenance interval, the damage accumulation mechanism needs to be fully appreciated.

The damage accumulation process is highly dependent on the operating history (unit usage) of the system. A good appreciation of the interdependency of the damage accumulation mechanisms due to cyclic duty application and continuous duty application is necessary for accurate accumulative damage modeling. Damage limit is the criterion for maintenance decisions. From this, it can be seen that a detailed review of the combination of operating history and the level of deterioration that it produced, is key to designing an outage plan for the units.

3.1.2 Preventive Maintenance, Planning and Scheduling

It has been addressed above that the gas turbine unit reliability is greatly influenced by the operating conditions. A reliability model, which is able to address the influence of operating conditions, is desirable for further maintenance analysis. Furthermore, such a model would allow the plant operator to make a forecast of reliability given a future operating profile. However, most of the reliability models that are currently available consider the calendar time or service time as the only parameters that influence the reliability characteristics of machinery during its operation. However, for HYDRO's gas turbines, the system age evolves as a function of a site specific utilization pattern.

The decision governing the timing of maintenance inspections is two-dimensional, one is to determine when the next inspection should occur, and the other is to determine the degree of intrusiveness that the maintenance work scope should take, i.e., what maintenance action to take. A factor in this Study is a review of the preventive maintenance that was carried out in the past in order to obtain an appreciation of how the current status has evolved. Also, to extrapolate the history of maintenance items and their costs to predict what can be expected over the next 15 years. This implies a projected maintenance schedule that takes into account a HYDRO defined target for the reliability, availability, and maintainability (RAM) of each of the units.

The operating conditions for the HYDRO gas turbines do not fit maintenance routines that are based on a fixed time interval that are in accordance with recommendations from the power plant supplier. A unit specific maintenance philosophy is therefore needed for effective gas turbine maintenance scheduling. For the unit specific maintenance approach, accurate historical reliability information and performance degradation for each gas turbine is necessary. Unfortunately in the case of the Hardwoods and Stephenville Gas Turbines such historical and performance degradation information does not appear to be available.

The historical maintenance practice has a strong impact on current engine performance and restoration requirements. Practices to restore performance and reliability would include; online water wash, off line water wash, combustion inspection/refurbishment, hot gas path inspection, and major inspection, steam cleaning, abrasive cleaning with hand scouring, and replacement of hot gas path parts with refurbished or brand new parts.

3.1.3 Advanced Technology

Application of new gas turbine technology is also an option for performance and reliability restoration. Advanced technology packages can improve efficiency, increase output, or extend maintenance intervals. HYDRO may consider individual upgrade packages such as new modern engines, power turbines and alternator as well as an entire new modern gas turbine to enhance the performance of its generating units, based on the increasing demand, needs of improving efficiency, or maintenance considerations.

A full evaluation of the economic benefit of advanced technology packages would require the consideration of the technical factors of the power plant, which include its configuration, performance, and reliability characteristics, and external market signals, such as price of fuel and price of electricity, future electric power demand and supply, electricity sales and fuel purchase contracts stipulations, etc. While this Study will consider several advanced technology options, the analysis will be high level and will be used for comparison purposes only against the refurbishment option.

3.2 ALTERNATOR/EXCITER RAM PERSPECTIVE

During operation, alternators are continuously subjected to electrical, mechanical, thermal and environmental stresses. These stresses act and interact in complex ways to degrade the machine’s components and reduce its useful life.

The life expectancy of an alternator depends upon its mode of operation, design, maintenance practices and operating incidents. Alternators that are operated as peaking units with many start-stops and also with high MVAR loads (high field currents), when in synchronous condenser mode, generally have a lower life expectancy – much shorter than a base load unit with few start-stops and operating near unity power factor with lower field current. Frequent start-stops expose the alternator to thermal stress due to heating and cooling cycles. This thermal cycling can reduce the life of the alternator and affect reliability. More frequent start-stops also tend to induce more mechanical wear on the insulation and will lead to more long term distortion on the copper conductors.

Alternators that operate primarily as base load units can expect to have an average useful life of approximately 30 years. On the other hand, alternators that see frequent start-stops and/or load cycling can expect to have a much shorter lifespan. Unfortunately, there is no exact formula to determine the useful life of a frequent start-stop machine; however, a unit operated in a frequent start-stop mode can expect an insulation life of from 30 to 50% that of a base load unit.

With the type of operation the Hardwoods and Stephenville alternators have been subjected to over the years – frequent stop/starts and synchronous condenser mode operation - expectations are that the stator core, stator and rotor windings/insulation, rotor retaining rings/end caps and bearings will all show signs of ageing and would be a risk area of concern for available and reliable operation over the next 15 years

In order to assess the condition and life expectancy of an alternator and its excitation system, it is important that electrical tests and inspections be carried out on a regular interval basis (annually; semi-annually; etc) over the years and the data recorded. A comparison of the test results taken over a period of time will usually indicate trending patterns good or bad. Refer to sub-sections 5.3.5 and 6.3.5 for further details on the type of tests and inspections that are typically carried out on an alternator as part of ongoing inspection and maintenance programs. Unfortunately for the purposes of this Study HYDRO was unable to locate information on electrical test data and inspections carried out on the alternators at either site over their 30 plus years of service, making condition assessment very difficult.

In addition, the frequent requirement to have the alternator available for service makes access for maintenance and testing difficult. This also raises serious concerns for providing the same type of availability for the next 15 years as has been experienced in the past. HYDRO must establish with its System Operations group defined intervals where outages are scheduled to carryout regular tests and inspections of the alternator and its excitation system.

The configuration of the Hardwoods and Stephenville Gas Turbines includes two engines, two power turbines and only one alternator. This makes the alternator a critical component in the availability and reliability of the Gas Turbines at each site. An alternator problem therefore can result in major unplanned outages.

4.0 GAS TURBINE FACILITY OPERATIONAL ISSUES AND MAINTENANCE

4.1 GENERAL

The Gas Turbine Facilities at Hardwoods and Stephenville have been in operation since the mid 1970's. While operational issues and maintenance information for the early years of operation were not available, HYDRO did provide a copy of the Operator's Logs for each site covering the period 1992 to 2007. In addition, HYDRO provided an extensive listing of work orders extracted from the J D Edwards work order system covering the period 1999 to 2007.

4.2 OPERATIONAL ISSUES

A review of the information provided, particularly over the past 5 years, revealed numerous failed starts and trips of the Gas Turbines at both sites resulting from:

- Sporadic mechanical and electrical equipment issues in balance-of-plant systems such as the fuel forwarding system; air compressor system; glycol cooling system; inadequately rated interposing relays, etc.
- Sporadic mechanical and electrical issues associated with auxiliary equipment on the gas generators engines and alternator such as exhaust gas temperature (EGT) spread in the engine burner system; clutch failed to engage or disengage; anti-icing issues; vibration trips; deflector rings disengageing; alternator reverse power trips; etc.

A copy of a HYDRO email of July 13, 2007 illustrating various ongoing troublesome sporadic operational issues at each site is included in Appendix 3.

The nature of these sporadic operational issues is such that any one issue might result in a failed start on a particular startup but not on the next. Many of the start failures and trips were often due to repetitions of the same initiating event. The failed starts occur whether the Gas Turbines are started locally or remotely from the Energy Control Centre (ECC) in St. John's. It appears there are also insufficient indications/alarms of the Gas Turbine operation taken back to the ECC. There should be a full review of inputs to the distributed control system (DCS) to determine the adequacy of alarm functions in general and inhibits particularly to the ECC.

The purpose of the condition assessment study is to identify potential problems in continuing to operate the Gas Turbine Facilities as they presently exist and identify solutions for maintaining and running the Facilities as reliable generating units for the next 15 years. While the Study, in conjunction with input from HYDRO, serves to highlight these sporadic operational issues, the Study schedule, budget and scope did not allow for a detailed investigation and resolve of these numerous ongoing sporadic operational issues.

Operational issues, particularly in the balance-of-plant mechanical, electrical and control systems are readily identifiable and fixable if the proper resources and budget are applied. From the information provided, it appears that HYDRO in the past has addressed these operational issues on an ongoing ad hoc basis rather than on a concerted overall project approach basis. To address these sporadic operational issues, several recommendations follow:

- It is recommended that HYDRO, as part of the Gas Turbines Refurbishment Project, assemble a dedicated in-house multi-disciplinary engineering team with responsibility to oversee the entire Refurbishment Project at each site.

- For the balance-of-plant mechanical, electrical and control systems sporadic problems in particular, it is recommended that HYDRO, as part of the overall refurbishment budget at each site, allocate an amount of money to address and resolve the sporadic operational issues in these systems. It is suggested that a preliminary budget amount of $250,000 be allocated for each site to cover the labour, expenses and material costs associated with addressing these balance-of-plant operational issues. The budget figure can be finalized following an initial detailed investigation by the refurbishment project team.

- For the sporadic operational issues pertaining to the major equipment – engines, power turbines and alternator - where repeated maintenance has not solved the problem, the major refurbishment recommendations and associated budget costs, arising from the Condition Assessment Study, are intended to address these issues. Report Section 7.0 provides details on these recommendations.

In summary, a dedicated project team with the proper resources, budget and schedule is necessary to properly carryout the refurbishment work at each site to provide reliable operation of the generating units over the next 15 years.

4.3 FACILITY INSPECTION AND MAINTENANCE

HYDRO provided a copy of the daily, weekly, semi-annual, annual, 5 year and 6 year inspection check lists governing inspections carried out on the Gas Turbine equipment at each site. The lists are included in Appendix 5. While only a few completed inspection check lists were available for review, it is assumed that such inspections are regularly carried out at the intervals noted. A review of these inspection check lists shows that with the exception of the 6 year protection and control (P&C) inspection, most inspections are of a mechanical nature. There are no electrical tests or visual inspections of the alternator (stator/rotor/exciter) listed on any of these check lists. Further, HYDRO was unable to provide historical electrical test data on the alternators at either site. It is recommended that HYDRO incorporate alternator tests and inspections similar to those listed in sub-sections 5.3.5 and 6.3.5 in these inspection lists on a go-forward basis.

As noted above, HYDRO provided an extensive listing of maintenance work orders extracted from the J D Edwards work order system covering the period 1999 to 2007. Many of the items listed in the JD Edwards printout could be categorized as routine maintenance considering the age of the Gas Turbine equipment and devices. There have however been a number of major work orders such as the replacement of the control systems at both sites with the ELSAG Bailey INFI 90 DCS system in 1997 (Hardwoods) and 1999 (Stephenville); a new AVR system at Hardwoods in 2006; refurbishment of one gas generator (engine) at each site in 1993 (Hardwoods) and 2000 (Stephenville) and rotor refurbishment work at Hardwoods in 1995. A listing of the major work carried out at each site is included in Appendix 3. Available Reports on the major refurbishment work carried out at each site over the 30 years of Gas Turbines operation were few. Several Reports on alternator rotor refurbishment work at Hardwoods were available, however there were no similar alternator refurbishment Reports available for Stephenville. The absence of major refurbishment Reports could indicate either no other major refurbishment work, other than that listed in Appendix 3, was carried out at each site over the past 30 years or the Reports could not be found.

5.0 HARDWOODS GAS TURBINE FACILITY CONDITION ASSESSMENT

5.1 GENERAL

This Section documents Stantec's observations and comments on the condition of equipment and structures at the Hardwoods Gas Turbine Facility. These comments are based on observations during the site visit on August 21/22, 2007, discussions with HYDRO staff and a review of documentation provided by HYDRO. Photographs taken during the site visit are included in Appendix 13. The Facility was broken down into the following areas for the condition assessment study:

- Gas Generators / Power Turbines and Auxiliary Systems
- Alternator / Excitation System
- Fuel Oil System
- Electrical Systems
- Control & Instrumentation Systems
- Buildings

This Section contains a number of recommendations on refurbishment work that HYDRO should consider in order to provide for the reliable operation of the Facility (Photo: HWD-001) for a further 15 years. **The recommendations and associated costs are summarized in Appendix 6.**

5.2 GAS GENERATORS/POWER TURBINES AND AUXILIARY SYSTEMS

5.2.1 Rolls Royce Olympus C Gas Generator Engines A & B

The Gas Turbine consists of two Rolls Royce Olympus C, 25 MW Gas Generator Engines (A and B) fired on #2 Diesel Oil, each driving a Curtiss Wright Power Turbine equipped with an SSS clutch. Each Gas Generator Engine has an air intake structure and each power turbine has an exhaust stack. New Olympus C Gas Generator Engines are no longer available from Rolls Royce. At the present time there are approximately 14 Olympus C Gas Generator Engine assemblies available in the market. In addition to the refurbishment of the existing Gas Generator Engines as recommended herein and in line with HYDRO's plans to keep the Gas Turbines at both sites operational for a further 15 years, it may be advantageous for HYDRO to consider obtaining a whole spare engine assembly as eventually all the spare Olympus C units will be scrapped.

The Olympus "C" type 2022 gas generator is a straight flow tubo-jet employing axial flow compressors driven by an axial flow turbine. A diagram (Figure 2-3) illustrating a cross-sectional view of the Olympus C Gas Generator is included in Appendix 4 to illustrate the various components comprising the Gas Generator. The combustion system uses eight combustors each with a burner contained in an annular outer casing. The eight combustion chambers are arranged equidistant around the turbine numbered from the top clockwise when viewed from the rear. An external air compressor system provides air to the starter motors. A Woodward Electronic Governor controls fuel flow. Further details on the Gas Generator auxiliary equipment can be found in sub-section 5.2.2.

Provision is made for heating the compressor entry guide vanes, nose fairing and the leading edges of the air intake casing during adverse weather conditions. The heating medium is air tapped from the #6 vane of the compressor casing and conveyed through a pipe to an electrically operated anti-icing hot air valve.

The lubricating oil system comprises an external tank that contains a heater system and a cooler that is cooled by means of the incoming fuel to the turbine combustors. The remainder of the system comprises pumps, level control system and oil delivery temperature control system. The return oil is pumped through a micro filter back to the reservoir tank.

A vibration pick-up is mounted on the gas generator casing flange, and it has a frequency range of 20-400cps. The signal is modified to read amplitude peak to peak and the system includes for alarm and trip points at preset levels.

Rolls Royce Olympus C Gas Generator Engine A (S/N 202205) has never been overhauled, and is currently in critical condition and not recommended to be run. Damage to the HP Turbine blades has compromised the structural integrity of the unit, of which hot fired running comes with a significant risk of complete blade failure and subsequent catastrophic damage to the unit and downstream equipment.

A fibreoptic borescope inspection of one (1) combustor assembly in the 10:30 position was conducted on Gas Generator Engine A and revealed significant damage and corrosion and depletion of the blade exterior coatings. Damage to three (3) HP turbine blades was observed and two blades showed evidence of material loss from the leading edge that was right through to the internal cooling air passage. There is significant risk of catastrophic failure within the turbine if this engine is operated. Otherwise, the Unit hot gas path general condition is commensurate with total operating time since new. Inlet air system deficiencies, allowing particulate such as rust to form and be ingested by the engine, have resulted in significant abrasive damage to the Compressor first stage blades, inlet bullet-nose assembly and Compressor front frame inlet guide vanes.

The Gas Generator Engine A auxiliary systems appear to be in serviceable condition - oil supply, scavenge, starting, ignition, cooling air, fuel delivery and vibration monitoring systems. The on-engine controls also appear to be in serviceable condition - speed indication, temperature sensors and Woodward speed governor.

Should HYDRO choose to have the complete package refurbished and operate for an additional 15 years, it is recommended that the Engine A assembly be removed, disassembled to allow for detailed internal inspection and major refurbishment as required.

Rolls Royce Olympus C Gas Generator Engine B (S/N 202223) was overhauled in 1993 and appears to be in good condition, above average for the time in service since last overhaul. Only minor exterior corrosion was noted, as well as minor depletion of the blade exterior coatings.

A fibreoptic borescope inspection of one (1) combustor assembly in the 10:30 position was conducted on Gas Generator Engine B and revealed no unserviceable conditions to all visible engine internal components. The inlet air bellmouth assembly is out of alignment and the resulting air turbulence will accelerate compressor blade root wear and will reduce power capacity by up to 500kW. Inlet air system deficiencies allowing particulate such as rust to form and be ingested by the engine have resulted in minor abrasive damage to the compressor first stage blades.

The Gas Generator Engine B auxiliary systems appear to be in serviceable condition - oil supply, scavenge, starting, ignition, cooling air, fuel delivery and vibration monitoring systems. The on-engine controls also appear to be in serviceable condition - speed indication, temperature sensors and Woodward speed governor.

Should HYDRO choose to have the complete package refurbished and operate for an additional 15 years, it is recommended that the Engine B assembly be removed, disassembled to allow for detailed internal inspection and major refurbishment as required.

It is suggested that compressor washing be conducted every 6 months. Crank soak washing is recommended over fired wash. A recommended cleansing agent – B&B 3100 – should be diluted with distilled or de-ionized water. Distilled or de-ionized water should also be used for the follow-on rinse.

When removing a burner for borescope inspection, it was observed that one of the burners was off-center in the combustor can. The washers associated with the burners are discrete distance pieces to accommodate the difference between the casing and the actual combustion can such that the burner nozzle is at the center of the can. Incorrect installation of the washers when performing maintenance work will cause this problem. This off-center burner arrangement could contribute to the exhaust gas temperature variances that have resulted in numerous exhaust temperature spread alarms experienced at the site. It is also important that all combustor cans on an engine are the same model. Installing different models on the same engine could further contribute to the exhaust gas temperature variations. It is important that maintenance personnel are fully informed of correct burner assembly when doing maintenance work on the engines.

HYDRO provided a copy of Inspection Report prepared by ALBA POWER reflecting their more extensive borescope inspection work carried out on the Hardwoods Olympus C Engines in May

2007. We have included the ALBA Report in Appendix 4 as the ALBA observations and recommendations are similar to the conclusions arrived at in this Study. In addition, the ALBA photos clearly highlight the issues associated with each Engine.

5.2.2 Gas Generator/Power Turbines Auxiliaries

Some auxiliary system components are obsolete and are no longer supported by the manufacturer or have been supplanted by more modern equipment. These include:

- Ignition exciters
- Vibration monitoring system
- Speed governors/fuel valve assemblies.

Replacement auxiliary assemblies of current design are readily available however they do entail costs that need to be considered. HYDRO should decide on its requirement for plant availability so that alternative strategies of installing new systems versus holding a stock of spare parts on site can be compared.

<u>Woodward Governors</u>

The Woodward speed governors were observed to be in satisfactory condition. Spares for the governors are readily available.

<u>Gas Generator Bearings</u>

The major line bearings were not accessible in the time allotted for inspection. The gas generator engine line bearings (8) are of the rolling element type. Inspection of the magnetic chip detectors indicated satisfactory bearings condition.

<u>Gas Generator Lube Oil System</u>

The engine's lube oil supply/scavenge system is self contained and driven by the engine assembly. It appears to be in satisfactory condition. The oil is cooled by means of a heat exchanger that uses incoming fuel oil as a coolant for the engine lube oil.

<u>Compressed Air System</u>

The compressed air system is of standard design and appears to be in reasonable condition for a further 15 years of service however the exact same components may not be available for the coming 15 years. A single spare compressor for both sites is probably adequate to provide for continuous plant availability. There are two starting air compressors mounted on the auxiliary module in an enclosed room within the Auxiliary Module Building and two storage tanks for start-air located outside the Building. The system provides sufficient air for three engine starts. The two air-cooled compressors are rated to deliver air at a discharge pressure of 500 psig.

Each compressor contains an air inlet filter and silencers, and are driven by two 7-1/2 HP AC motors.

The two compressed air storage tanks (receivers) are sized to provide sufficient volume for at least three repeated starts of the gas generators. Relief valves are mounted on each tank to protect it from overpressure. Water traps are provided to automatically remove the condensed water from the bottom of each of the storage tanks. There is also a heating cable included in the drain circuits. The control system provides conventional start/stop control with lead/lag compressor selection. Compressor instrumentation appears to be in good working order.

Starter Motors

The starter motors have provided high reliability, but the model is no longer supported by Rolls Royce. It is suggested that a spare unit compatible with all four gas generators, should be carried by HYDRO. (The inventory of spare parts dated 2004, included one starter motor assembly).

5.2.3 Inlet Air Systems A & B

The original inlet air filter system at Hardwoods was redesigned in the early 2000's. The new filtering system consists of a monoclone pre-filter and a high efficiency second filter. This system is different than the inlet air filter system at Stephenville which still retains the original design. Refer to sub-section 6.2.3 for details on the Stephenville system.

The inlet air structures (Photo: HWD-002) are constructed of structural steel plate and framing supported by a cast-in-place concrete foundation. The concrete foundation was found to be in adequate condition and there were no visible cracks or deterioration noted. As well, no significant structural steel issues were noted during the inspection. The exterior coating was found to be in poor condition with surface corrosion and flaking of the coating noted in several locations over the exterior of both Air Inlet structures. Based on the condition of the existing coatings, we recommend that the Air Inlet structures be cleaned, prepared and recoated within the next two (2) years (Photo: HWD-003).

There were several items noted during the inspection that require maintenance work. The interiors of inlet air plenums A and B show signs of advanced corrosion damage. Surface corrosion of the steel and flaking of the coating was noted inside the air inlet structures and is compromising the effectiveness of the air inlet filtering system (Photo: HWD-004). The basic structural integrity is good, and can be returned to satisfactory condition with basic sand blasting and replacement of the surface coatings on the interior of the air inlet plenum and silencers. The concrete slab on grade was found to be in acceptable condition.

Significant corrosion was also noted in the trough under the access doors for both air inlet structures. This corrosion is likely a result of water accumulation in the trough over extended periods of time. We recommend that the following items be completed to repair this problem and help prevent it from reoccurring:

- Sand blast and coat all areas corroded under the access doors to the air inlet plenums (Photo: HWD-007).
- Weld new plates inside the troughs that will drain water to the centre of the trough.
- Drill a weep hole in the exterior of each air inlet structure to allow water to drain from the trough under the access doors.
- Replace the weather stripping on the access doors (Photo: HWD-006).
- Install a new drip cap over both access doors similar to the drip caps over the man doors on the gas generator/turbine modules and alternator modules (Photo: HWD-004).

Surface corrosion was also noted inside the filter enclosure at the top of both Air Inlet structures. We recommend that these interior spaces be cleaned, prepared and recoated when the exterior of the air inlet structures are recoated (Photo: HWD-005).

It was noted that the kick plates on the ends of the platform attached to the air inlet structure for Unit A are missing. This is in violation of fall protection regulations and should be repaired as soon as possible. During the site inspection, it was also noted that the ladders providing access to these platforms were quite narrow and did not flare out at the top. This made it quite difficult to exit and enter the ladder. We recommend that these ladders be replaced with new ladders that have proper widths at the top (Photos: HWD-008 & HWD-009).

The screens on the air inlet structure for Unit B were found to be highly corroded. These screens should be cleaned, prepared and recoated when the exterior of the air inlet structures are recoated (Photo: HWD-010).

In the case of Air Plenum A, there is evidence of silica sand, rust scale and small rocks in the inlet plenum, which eventually will be ingested by the turbine engine. It was noted that the second, inner row of rubber sealing strips is missing, allowing debris to enter the inlet plenum assembly from the basic structure “C” channel. In addition, impact damage to one of the inner silencer panels has torn the perforated sheet at that location.

In the case of Air Plenum B, there is evidence of silica sand and rust scale in the inlet plenum, which eventually will be ingested by the turbine engine. It was noted that the inlet bellmouth assembly on Engine B is not fitted correctly to the engine, causing inlet air turbulence and loss of efficiency. The assembly is out of alignment approximately 1.0 cm. creating significant turbulence to the inlet air stream. As the Engines during full power settings ingest over 240 Lbs/Sec. of air, the importance of correct bellmouth fitment cannot be overemphasized. Misalignment will create turbulence in this air stream, accelerating compressor blade root wear, and costing 500kW, or more of potential power output loss.

There is a misalignment between the attachment plate of the lifting beam and the air plenum structure that needs correction.

HYDRO staff should be made aware of the criticality of keeping the inlet air systems clean, and not allow small rocks and debris to remain in the systems following inspections and periodic maintenance. In the case of air inlet system A, the inner row of rubber sealing strips are deteriorated to the point of cracking and no longer making effective seals against unwanted air leaks.

5.2.4 Exhaust Stacks A & B

The exhaust stacks (Photo: HWD-002) for both power turbines are constructed of a heavy gauge steel plate with light gauge steel cladding on the exterior. The exterior cladding of the lower half of the exhaust stacks is constructed of heavy gauge steel plate. The exhaust stacks are supported by a cast in place concrete foundations. Based on information provided by N&L Hydro, these stacks were replaced in 1992. The interior silencer panels were reused. The snow doors on the exhaust stacks were modified from electric actuation to pneumatic operation in the mid 1980's. New expansion joints were installed in the stacks in 2004.

The foundation under the exhaust stacks was visually inspected and was found to be in acceptable condition with no visible cracking or significant deterioration. A grid of steel bars spans the area immediately above the engine exhaust the purpose was reported to be for preventing silencer panels from dropping and damaging the turbine, and also as a support for scaffolding for maintenance. Several of the internal grid bars retaining nuts have backed off to the inner end of the threads and should be re-tightened.

The light gauge exterior cladding on the upper portion of the exhaust stacks was found to be in poor condition. The cladding is very light gauge material with no corrugations. The cladding was generally warped and bent and could easily be deflected with light pressure, even from wind loads. Holes that appear to be pop rivet holes were noted in many locations on both exhaust stacks. Larger holes have also developed in the light gauge cladding in several locations as a result of corrosion. As well, the joints between panels of cladding are not sealed or lapped sufficiently to prevent water infiltration into the exhaust stack enclosure. These unsealed joints, large holes and the pop rivet holes allow a significant amount of moisture and water into the exhaust stack enclosures, which will lead to excess corrosion of the main structural elements and failure of the insulation. We therefore recommend that this cladding system be replaced with a new corrugated metal cladding system (Photos: HWD-011 & HWD-012)

The coating on the heavy gauge cladding on the lower portion of the exhaust stacks was also found to be in poor condition. Surface corrosion and coating failure was noted in several locations on both exhaust stacks. We recommend that this part of the exhaust stacks be cleaned, prepared and recoated within the next two (2) years (Photo: HWD-013).

In the A exhaust stack, cracking is evident at two of the corners of the stack access door opening in the inner liner. As well, cracks in the inner liner were also noted directly below the door opening and in the internal rolled edge. These cracks are easily repaired and we recommend that repairs be completed at the next available opportunity (Photos: HWD-014 & 015 & 016). The remainder of the exhaust system appears to be in satisfactory condition.

The snow doors on the exhaust stack for Unit A were found to be in poor condition and in need of replacement. Significant corrosion was noted on the main structural members and the end of two (2) beams has completely corroded away. The snow doors on the exhaust stack for Unit B were also found to be in poor condition and in need of replacement. Significant corrosion was noted on the main structural members. We recommend that these doors be replaced within the next year given the level of deterioration in the structural steel members (Photos: HWD-020 & 021).

In the B exhaust stack, cracking is evident at the bottom edge of a lifting eye access hole on the internal rolled edge and at the upper two corners of the stack access door opening in the inner liner. Several cracks in the welds, which holding the interior mesh and insulation in place were also noted. Simple weld repairs will correct this cracking and should be carried out at the next available opportunity (Photos: HWD-017 7 018 & 019). The remainder of the exhaust system appears to be in satisfactory condition.

The doors providing access to the exhaust stacks are also in need of upgrades. The current door design is heavy and is not supported by hinges and is simple bolted in place. Therefore it is difficult and time consuming for staff to remove the doors. As well, there are no drip caps over the doors and the seals are inadequate. These doors are therefore leaking and causing corrosion in the exhaust stacks and gas turbine enclosures below. The doors should be reworked so they are on hinges, have drip caps and have proper seals to make them weather tight. The hatches below these doors in the roof of the gas turbine enclosure must also be modified to prevent water leaks when these exhaust stack doors are modified (Photo: HWD-022).

During the site inspection it was also noted that the ladders providing access to the platform on the exhaust stacks were quite narrow and did not flare out at the top. This made it quite difficult to exit and enter the ladder. We recommend that these ladders be replaced with new ladders that have proper widths at the top (Photo: HWD-008).

5.2.5 Curtiss Wright Power Turbines

There are two Curtiss Wright Power Turbines A and B. Each Curtiss Wright power turbine is a two-stage axial flow unit with the rotor assembly and main shaft supported as a cantilever by two white metal bearings housed in a pedestal. The power turbine unit is connected to the gas generator by a gas duct incorporating a bellows joint. The gas generators receives ambient air from the air inlet plenums and delivers high temperature and pressure gas to the power turbines which converts the thermal energy into rotating mechanical power. The power turbines output shaft is coupled to the alternator through SSS clutches.

The two-stage axial flow rotor consists of two rows of cast Stellite 31 blades. The blades are attached to a forged 422 stainless steel disc; the blades are secured to the disc by fir tree root fixings. The rotor assembly consists of a front labyrinth ring, first stage blade and disc assembly, spool spacer, interstage labyrinth, second stage blade and disc assembly and the main shaft. The components are fixed to the main shaft by tie bolts. A diagram (figure 2-58) illustrating the power turbine assembly is included in Appendix 4.

The oil supply to the power turbine is supplied from the alternator module and provides lubrication to the front and rear main radial bearings and the thrust bearing.

The stator casing was originally made of austenitic nodular cast iron alloy, split on the horizontal centre-line to facilitate access to the stator vanes and the rotor. The casings however were prone to severe cracking resulting in a de-rating of the gas turbine for a number of years. In the 1980’s new casings were designed, manufactured and installed on both gas turbines. The new casings used an incanol alloy that is less prone to cracking. There have been opportunities to inspect the blading of end B at Hardwoods when the gas generator was removed for extensive overhaul in1993. The Curtiss Wright Power turbines A&B have provided excellent service since the major modifications to the casings. There have been no records of significant problems noted or significant work carried out on the power turbines over the past 12 years other than a requirement to re-balance the A Power Turbine at Hardwoods in 1995.

The elements that could impact on the reliability and availability of the Power Turbines are the blades, discs, bearings, and vibration characteristics. These are somewhat inter-related with uneven deterioration of the blades leading to degradation of bearings and vibration characteristics.

Access to the exhaust stacks internals, during the site visit, allowed viewing of the Deflector Rings, Second Stage Power Turbine Blades and Second Stage Power Turbine Nozzles on both Power Turbines A and B. No unserviceable conditions were noted, and all visible components appear to be in a condition above average for the total time since installation and run hours.

From our review of operations of the Hardwoods Facility particularly the minimal running time on the power turbines and our visual examination during the site visit, there is no expectation that the Power Turbines performance will change significantly during the next fifteen years. We recommend however that upon removal of the Gas Generator Engine assemblies as noted in sub-section 5.2.1, the Curtiss Wright power turbine assemblies should be inspected in detail to verify the mechanical integrity of the units. In order of priority the following points are recommended to be inspected/ refurbished:

- Main line bearings to be removed and inspected;

- Turbine blades to be removed and metallurgical sampling done to verify alloy composition, as well as check wear to the blade roots;
- Turbine disks to be removed and metallurgical sampling done to verify alloy composition and creep growth.

More modern and effective anti-corrosion/thermal protection coatings are available, and are recommended to be applied to the power turbine blades and nozzles to give superior protection/reliability for future operation.

5.2.6 SSS Power Turbine Clutches A & B

The SSS Clutch is designed for use between a turbine and an alternator to primarily engage and disengage the gas turbine from the alternator when the alternator operates as a synchronous condenser. When operating for generation purposes the clutch will remain engaged with the alternator. In the case of synchronous condenser operation, the clutch can automatically connect the turbine to the alternator at any speed, with engagement occurring immediately when the turbine speed exceeds that of the alternator. The design accommodates changes in the alignment of the gas turbine and alternator shafts to allow for thermal expansion effects. It acts as a double toothed flexible coupling with tooth surfaces that are designed for low stress and are hardened by nitriding. The clutch is lubricated by oil catchers on the input and output shafts. A dashpot system provides oil to maintain clutch engagement in the event of a reduction of turbine power to the idling mode.

The Power Turbine Clutches A and B were not accessible in the time allotted for inspection during the site visit. A review of available operational history indicates that most problems associated with the clutch assembly have originated with the various sub-systems such as – position indication, brake function and shifting mechanism. All other history indicates satisfactory operation of the clutch assembly itself.

During the site visit on August 21, 2007, when attempting to startup Engine A, and engage it with the rotating alternator (synchronous condenser mode), both the Alternator & Engine A tripped. Indication was that the clutch had not engaged within a prescribed time, resulting in the trip. Following a post mortem conducted by HYDRO it was determined that the clutch had actually engaged, however in doing so, the cover of the clutch proximity switch had been ripped off, while the clutch was engaging, causing the switch to malfunction and send an erroneous signal to the DCS system. There appears to be a physical interference problem with the proximity switch when the clutch engages. HYDRO noted this problem has occurred before on both engines however more frequently on the A end than the B end of the Gas Turbine.

A Report by Maxwell Reid on alternator refurbishment work carried out in 1995 (refer to sub-section 5.3.4 for further details) also noted that the clutch cover, fabricated at the time by Mercer's Machine Shop, was found to be too long and needed further work. It was also found that the proximity switch on the "A" end clutch was mounted too close to the ring on the clutch cover fabricated by Mercer's. Since there are still problems with mechanical interference between the clutch engagement and the proximity switch on the "A" end clutch, we recommend that HYDRO investigate the clutch assembly to determine if current interference problem between the clutch and the proximity switch is somehow related to the work done in 1995.

There has been no reported significant work carried out on the Clutches over the past 12 years. The clutch system itself has provided good service and should continue to do so for the next 15 years. There have been a number of problems with the auxiliaries such as the hydraulic system and the position monitoring. These have resulted in difficulties to clutch operations when synchronizing the power turbine with the spinning alternator. It is advised that the components comprising the auxiliaries to the clutches be reviewed for potential replacement with currently available and proven reliability components.

It is recommended that when the gas generator engines have been removed for refurbishment the drive clutches be completely disassembled and inspected. No major structural problems are anticipated; however the brake, position indication and actuation systems should be refurbished and tested to achieve continued reliable operation. It may be prudent to place spare internal components into inventory, as the availability of such parts into the future are unknown and may be cause for concern.

5.2.7 Main Power Train Bearings

The Main Power Train bearings support the power turbines, clutches, and the alternator/exciter. They are of the journal, pressure lubricated type, but they were not accessible in the time allotted for inspections. Review of oil sampling results with operational staff indicated no anticipated problems with these bearing assemblies. However it was noted that the unit vibrations were pronounced at the A assembly end and this could be caused by a defect in the bearing at that end.

Significant ground and background vibration is evident while the alternator is operating in synchronous condenser mode. The non-exciter end bearing location specifically appears to be the source of the vibration and a trim balance is recommended to be performed at the earliest opportunity to bring this vibration down to lower levels. The station vibration monitoring equipment shows the non-exciter end of the generator to have four (4) times higher residual imbalance than the exciter end. This vibration is exciting much of the package hardware and will contribute to metal component fatigue, and possible shortening of the gas generators' rolling element bearings.

5.2.8 Main Lube Oil System

The main lube system is a closed loop that incorporates a tank that is partitioned internally to allow for entrained gas (air) in the return to evacuate. The tank is large enough to store and maintain oil temperature. Oil is delivered under pressure to the power turbine, clutches and alternator and is returned to the tank by gravity and negative pressure generated by a vacuum fan on the tank.

The oil is moved and pressurized by the lube oil pumps located in the Auxiliary Module Building. Constant pressure is maintained in the discharge header by means of a regulating valve which establishes a header discharge pressure of 30 psi (2.04 bars) by sensing discharge pressure after the cooler and filters. The pumps are protected by a relief valve which is set at 100 psi (6.8 bars) and will bypass lube oil in the event of system blockage.

The power turbines, clutches and alternator low pressure lube oil system proper all appear to be in satisfactory condition. The high pressure rotor jacking oil system also appears to be in satisfactory condition.

From the lube oil pumps, the oil flows to an oil/water-glycol cooler. The cooler is a shell and tube type heat exchanger with internal baffles that allows a heat exchange from the oil to the coolant glycol, which is actually a glycol - water solution.

The glycol coolant from the main lube oil cooler is circulated by pumping through a 3-way valve that controls the quantity re-circulated back to the oil-cooler or to the glycol/air heat exchanger (glycol-cooler). As the main lube oil delivered from the oil tank gets warmer, the 3-way valve will operate under the control of its capillary, and will slowly restrict the re-circulating glycol coolant such that the coolant has to pass through the external glycol/air heat exchanger and then back via the 3-way valve where it is mixed with the warmer coolant still circulating, and then to the main lube oil cooler. In this manner, the 3-way valve controls the flows in the coolant sections of the heat exchangers to maintain a steady delivery temperature of oil to the bearings.

The main lube oil system electrical, mechanical and instrumentation equipment is generally in good condition but if certain components such as pumps or fans fail completely, it may be difficult to find the identical item for replacement. The necessary precaution would be to acquire spares for HYDRO to stock. This is particularly relevant to the single glycol circulating pump and the three-way valve, because the power plant will be unavailable for operation in the absence of these components. HYDRO should decide on its requirement for plant availability so that the alternative strategies of installing a back-up pump or valve versus holding a spare pump/valve on site can be compared. (Some replacement parts were identified in the spare parts inventory 2004, for a glycol pump. It is not clear whether the pump associated with the spare parts is the Main Lube Oil Cooling System, or for the Alternator Cooling System at Stephenville).

5.2.9 Glycol Cooler for Main Lube Oil Cooling System

The external glycol heat exchanger (Photo: HWD-023) is of the finned tube air blast type with its electrically-driven cooling fans and the coolant circulating pump controlled by a sequencer. The main lube oil external glycol cooler assembly is in satisfactory physical condition.

It is our understanding that maintenance work was completed on the existing glycol heat exchanger last year. This work included the replacement of the bottom section of the heat exchanger and other minor repairs. A visual inspection of the new and old steel structure was carried out and all steel members were found to be in satisfactory condition. However, it was noted that the coating on the older structural steel members and canopy was failing. Surface corrosion and flaking of the coating was noted in several locations. We, therefore, recommend that the entire steel structure and associated cladding be cleaned, prepared and recoated within the next two (2) years (Photo: HWD-024).

5.2.10 Gas Generator/Turbines Enclosures A & B

The gas generator/turbine modules are constructed of structural steel framing with steel plate exterior cladding. The exterior coating was found to be in poor condition with surface corrosion and coatings failure noted in several locations. We recommend that the exterior of both gas turbine enclosures be cleaned, prepared and recoated within the next two (2) years (Photo: HWD-025). The roofs of the gas turbine enclosures are not sloped and water ponds on the roofs in places. This is contributing to the coatings failure and corrosion of the roof steel. The concrete foundation under the gas generator/turbine modules was visually inspected and was found to be in acceptable condition with no visible cracking or significant deterioration.

A visual inspection of the gas generator/turbine module supports and welds was carried out and no issues were noted. A visual inspection of the exposed steel structure inside the gas turbines modules was also completed. It was noted that there were some areas in which surface corrosion was present on structural members. Water is also entering the gas turbine enclosure from the exhaust stack doors above. These doors should be modified to make them weather tight prior to recoating the gas turbine enclosures and exhaust stacks. These areas were generally small and the corrosion mild and therefore are not a significant concern at this time. However, if this facility is to remain in operation for the next 15 years, the next time the gas turbine equipment is removed for maintenance, we recommend that the interior of the gas generator/turbine modules be cleaned, areas with corrosion sandblasted and the interior of the modules be recoated (Photo: HWD-026).

The existing man doors in the gas turbine modules do not have any windows. We recommend that windows be added to the doors for safety purposes. This will allow Hydro site personnel to view the interior of the module before opening the door. This would be particularly helpful should there be a fire inside the gas generator/turbine modules.

5.2.11 Fire Detection and Protection

The fire suppression system consists of Inergen systems located in (i) the turbine enclosure (Modules A and B), (ii) the alternator enclosure (Clutch A and B compartments) (iii) in the fuel unloading building, (iv) in the fuel forwarding building, (iv) the auxiliary module building and (v) the control building. There are heat and smoke detectors located at each location. The Inergen fire suppression systems are in excellent condition and available for service for an additional 15 years.

5.2.12 Gas Generator/Turbine Spares

An observation made during the visit to Hardwoods, and during inspection of the available outage/maintenance reports provided, is that if additional spare parts inventories were held on-site, the overall reliability of the package could be enhanced. Recommended Gas Generator Engine spares include:

- Fuel injection nozzles: A majority of unscheduled shut downs are caused by high exhaust gas temperature deviation. A spare set of flow balanced fuel injection nozzles would allow mechanical staff to replace defective nozzles with serviceable units, to bring total temperature deviation to within acceptable limits.
- Starter assembly: These units are no longer available from the original manufacturer, and are understandably critical to the operation of the package. A spare starter assembly would enhance current and future reliability.
- Glycol Circulation Pump
- Three-way Glycol Mixing Valve

There are companies that hold spare parts and complete gas generators in anticipation of future requirements. We recommend a strategy whereby HYDRO can set up a system of quick replacement if needed. It is unlikely that both gas generators will become unserviceable simultaneously allowing the alternator to be operated as a synchronous condenser or at 50% MW output on one or other gas generator.

5.3 ALTERNATOR/EXCITATION SYSTEM

5.3.1 Alternator Description

The Hardwoods Alternator and Excitation System were manufactured by the Brush Electrical Machines Ltd. of England in 1976. The Alternator was designed to ANSI Specification C50-13. The 13,800 volt, 3 phase 3600 rpm Alternator is an air cooled machine rated at 63,340 KVA at a 0.85 power factor. The Alternator utilizes a rotating brushless type exciter mounted on a stub to the main rotating shaft.

The Alternator cooling consists of an air supply system that includes a baffle system for cyclonic separation of particles, followed by a micro filter system. The clean air is induced into the alternator by fan blades mounted on the alternator main shaft, and is rejected from the system via exhaust louvers.

The Alternator/Exciter System is contained in a weatherproof, walk-in sound insulated enclosure. The stator is fastened to the enclosure bedplate. The Alternator is enclosed with two end canopies (bulkheads) and a top section canopy. Each canopy is accessible via doors. The alternator enclosure is protected by an Inergen fire suppression system. Refer to sub-section 5.3.7 for further details on the Alternator/Exciter enclosure.

The alternator's inner stator frame is fabricated from structural steel, welded together to form a rigid structure. The stator core consists of low loss, silicone steel segmental stampings insulated by a layer of varnish on both sides of each lamination. The core is divided into short sections by radial ventilating ducts. The core is bolted to the stator frame. The stator copper winding is of the two layer diamond type with the coils held in open slots by epoxy paper laminate wedges. The two coil layers are separated by epoxy paper laminate wedges. The insulation is Class B synthetic resin bonded mica glass tape. The stator winding laminations are transposed in a regular pattern to minimize circulating currents and losses. The coils are protected against corona formation by coating in the slot length with conducting (graphite) paint and with corona relief paint at each end of the core. The end winding coils are braced with glass cord and densified epoxy paper laminate blocks and supported from the core ends by insulated brackets.

The stator line and neutral terminals are brought out to a cubicle containing the line and neutral bushings. The line bushings are connected to a metal enclosed bus duct system. The Alternator neutral is grounded via a grounding transformer and resistor (refer to section 5.5 for further details on the bus duct, the alternator circuit breaker and neutral grounding).

The rotor consists of a solid carbon steel forging carried in two bearings with a shrunk on half coupling. The field windings are located in slots milled into the rotor forging. The windings are held in place by steel and bronze wedges. Intertooth slots are milled to provide a longitudinal air passage for the cooling air. The windings consist of multi-turn copper coils insulated throughout with Class F mica. The end windings are supported by non-magnetic end caps shrunk on to a spigot on the rotor body and braced with resin bonded asbestos fabric packing blocks and boxed in with a steel end bracket. The material used in the end caps could not be determined from a review of available documentation. Early end caps used 18%Mn / 4%Cr non-magnetic material whereas more current designs use 18%Mn / 18%Cr. The former is susceptible to stress-corrosion cracking. It is recommended that the end caps be closely examined during the refurbishment project.

The alternator and exciter bearings (3) are carried in a fabricated steel pedestal. The housing is split horizontally on the shaft centerline. The bearing is white metal lined and spherically seated. Bearings are lubricated by pressurized oil at 20/30 psig (refer to sub-sections 5.2.7 and 5.2.8 for further details). The oil drain systems operate below atmospheric resulting in air being drawn in through the labyrinth seals providing the necessary ventilation. A high pressure jacking oil system is provided for start-up and shut down purposes.

The stator winding temperature is measured by embedded resistance temperature detectors (RTD's) distributed throughout the windings in the slots. There are 4 RTDs per phase. Alternator air temperatures are measured by thermocouples fitted in the air outlets and inlets from the stator as well as the exciter air outlet. The temperature of the drain oil in each pedestal bearing is measured by an immersed thermocouple. A vibration detector is mounted on the pedestal of each rotor bearing and on the exciter bearing pedestal.

5.3.2 Excitation System Description

The main exciter is of the rotating brushless type mounted on a stub shaft which forms an extension of the main drive shaft at one end of the machine and is supported by a third bearing. The brushless exciter was designed to ANSI Specification C50-13. The excitation volts are 36.0 volts dc. The exciter has stationary field coils and a rotating armature. The exciter field windings are on the stator and its armature is on the rotor. The AC output from the exciter armature is fed through a set of diodes that are also mounted on the rotor to produce a DC voltage. This is fed directly to the field windings of the main alternator which are also located on the rotor. The excitation control system consists of a "Normal" and "Standby" automatic voltage regulator (AVR) backed up by a "Manual" control mode. The AVR controls the strength of the magnetic field in the exciter by varying the amount of current through the stationary exciter field windings. The Hardwoods Gas Turbine utilizes the original brushless exciter system provided in 1976. The original excitation AVR control system at Hardwoods was replaced in 2006.

5.3.3 Alternator/Excitation General Assessment

As noted previously, the configuration of the Hardwoods Gas Turbine includes two engines, two power turbines and only one Alternator. This makes the Alternator a critical component in the availability and reliability of the Gas Turbine. An Alternator problem therefore can result in major outages.

While HYDRO personnel have indicated the Alternator and Exciter have generally provided good reliable service at Hardwoods, the actual condition of the stator, rotor, exciter and auxiliary components is unknown. HYDRO was not able to provide documentation, during the Study, outlining a history of Alternator and Exciter condition testing on this equipment ie data from electrical tests and inspections carried out on the equipment over the years. In order to properly assess the present condition and life expectancy of the Alternator and Exciter, it is very important that data from such tests and inspections if carried out on the equipment over its years of operation be current and available for review. Unfortunately, this information was not available. A comparison of the test results taken over a period of time will usually indicate trending patterns good or bad. Since this information was not available, such an assessment was not able to be carried out in the Study.

With the type of operation the Alternator has been subjected to over the years – frequent stop/starts and synchronous condenser mode operation (refer to sub-section 2.1) - expectations are that the stator core, stator and rotor windings/insulation, rotor retaining rings and bearings will all show signs of ageing and would be a risk area of concern for available and reliable operation over the next 15 years. In addition, as discussed in sub-section 5.3.4, the rotor at Hardwoods has had significant refurbishment work carried out in the past. Typical alternator stator and rotor problems that can develop over time from such operation can include:

<u>Potential Alternator Stator Problems</u>

- Stator winding insulation integrity and cracking
- Stator windings -- bar movement, sparking, bulging or puffy coils
- Stator end windings – bar movement, loose/broken bracing and ties, corona (arcing) activity
- Stator wedges – looseness, sparking damage
- Stator core insulation – hot spots. Shorting or low resistances in the inter-laminar insulation may result in abnormal currents, localized heating and iron damage.
- Cracked connections
- Contamination

<u>Potential Alternator Rotor Problems</u>

- Shorted turns and field grounds – occurs when the insulation in the field is damaged. There are a number of factors that can lead to field insulation breakdown/degradation – (i) length of time the alternator has been in service (ii) mode of operation – frequent start-stops (thermal cycling) or base load operation and (iii) contamination introduced into the machine
- Rotor wedges -- looseness, sparking damage
- Thermal sensitivity – is a term used to describe an excessive vibration of the rotor induced by the heating effect of the field current. As field current flows, the copper winding heats up and having a greater coefficient of thermal expansion, expands more than the steel forging. The disparity in expansion transmits forces to the forging through the rotor slots, wedges and retaining rings. The heat generated in this manner is normally drawn away by the cooling medium (air). Problems can occur when the winding forces act unevenly or when a temperature differential exists across the rotor due to blocked ventilation. These events will cause the rotor to bow somewhat resulting in an imbalance and subsequent vibration.
- Negative sequence events -- operating incidents (closing the alternator breaker when at standstill; single phase operation; transients, etc) that induce heating, arcing within the alternator
- Contamination – problems that arise from contamination buildup on the rotor include low megger readings, overheating and creepage failures

- Forging/retaining ring damage – rotor forgings over time can develop cracking or burning caused by extraordinary events such as negative sequence currents flowing in the forging. Retaining rings are the highest stressed components of the alternator. Alternators operating in cycling modes that require frequent start-stops are susceptible to rotor tooth top cracking. It is generally recommended that rotors that have been in service in excess of 25 years with approximately 5000 start-stops should be inspected for damage.

In the absence of electrical testing and inspection records on the Alternator over its 30 years of service, it is difficult to determine if any of the potential problems listed above currently exist or might occur in the next 15 year period. In order to determine the present condition of the Alternator and Exciter, the following recommendations are proposed:

- A series of electrical tests in line with sub-section 5.3.5 be carried out on the Alternator at the earliest opportunity to provide a snapshot on the current condition of the Alternator.
- In addition to the electrical tests noted above and in order to determine what specific refurbishment work might be necessary on the Alternator in particular, it is recommended that the Alternator itself or as a minimum the rotor be physically removed from its enclosure and the visual inspections and electrical tests noted above be carried out. This detailed examination will clearly determine the condition of the Alternator and its components and the specific refurbishment work (if any) that must be carried out to ensure its ability to operate reliably for a further 15 years.

5.3.4 Alternator/Excitation Operational and Maintenance Issues

The preceding sub-section listed potential alternator stator and rotor problems that can develop over time. This sub-section will outline problems noted by HYDRO personnel and refurbishment work carried out on the alternator in the past.

There are reported incidents of vibration alarms occurring on the exciter end of the Alternator on start-up. The reason for or cause of the vibration alarm has not been identified to date. This alarm could be caused by a number of factors:

- faulty vibration detector,
- shorted turns in a field coil,
- rotor balance issue,
- shaft alignment issue, or
- bearing issues.

Two Reports were provided by HYDRO on significant maintenance/refurbishment work carried out on the Hardwoods Alternator in 1983 and 1995.

- In 1983, after only 6 -7 years of operation, rotor earth faults caused significant damage to the rotor insulation primarily at the exciter end beneath the rotor end cap. The indicator of this problem was a trip of the Gas Turbine due to high vibration during synchronous operation. The repair procedure involved pulling the rotor from the stator and removing the rotor end caps to repair the fault. In fact, the under cap insulation on both ends of the rotor were brought in line with the current Brush rotor insulation at the time. The rotor fan and balance ring were also replaced. The rotor was demagnetized and realigned in the stator. (Reference: Report by Arden Turpin of Engineering Services dated September 21, 1983.)

- In 1995, further work was carried out on the rotor. At that time, the rotor was re-wedged and taped. A Brush Report on the details of the work carried out was not provided, however there is a reference to this work in a FERN Engineering Inc Report No. 5444-08-2 dated September 27, 1995 and further reference in a Report prepared by Maxwell Reid, Acting GT Electrical Operator in August 1995.

  Following the work carried out by Brush and re-assembly of the Alternator, high vibration was noted at the “A” end of the Gas Turbine. The FERN work found the rotor to be unbalanced at both ends. The rotor was balanced. In addition, the “A” end power turbine was also successfully balanced. It was noted in the Fern Report that the power turbine high vibrations occurred at the rear bearing (clutch end) and this bearing has a tendency to be unstable because of its light loading. The instability is more noticeable at low power levels.

  The Maxwell Reid Report also noted that the clutch cover, fabricated at the time by Mercer’s Machine Shop, was found to be too long and needed further work. It was also found that the proximity switch on the “A” end clutch was mounted too close to the ring on the clutch cover fabricated by Mercer’s. There are still problems with mechanical interference between the clutch engagement and the proximity switch (refer to sub-section 5.2.6 for further details).

These Reports indicate that significant work was carried out on the rotor over the years. There is no reported significant work carried out on the alternator over the past 12 years. Whether the significant work carried out on the Rotor in the past will be a factor in the future cannot be determined quantitatively or qualitatively without a further thorough examination of the rotor to assess its current condition.

The original excitation AVR control system at Hardwoods was replaced in 2006 with an ABB DCS 500 Unitrol F Series System type AFT-O/C1F1-F63. The new AVR control system is reported by HYDRO as performing well since installation.

5.3.5 Alternator/Excitation Testing Program

In order to assess the condition and life expectancy of the Alternator and its Excitation System, it is important that electrical tests and inspections be carried out on a regular interval basis (annually; semi-annually; etc) over the years and the data recorded. A comparison of the test results taken over a period of time will usually indicate trending patterns good or bad.

The following types of electrical tests are often carried out on an alternator and excitation system as part of ongoing inspection and maintenance programs:

Stator Electrical Tests

- EL-CID tests --- detects problems in the stator core especially inter-laminar insulation defects (hot spots)
- Partial Discharge Test --- detects stator winding insulation deterioration
- Polarization Index Test --- tests the insulation resistance to ground
- Hi-Pot Tests --- Insulation test
- Megger Tests at 1000 or 5000 V DC
- Thermocouple tests/calibrations
- Inspection and tests of Alternator bushings

Rotor Electrical Tests

- Megger Tests at 500 V DC -- detects rotor winding insulation deterioration / contamination
- Rotor winding resistance measurements

Bearings Electrical Tests

- Megger tests to indicate general cleanliness of bearing pedestal and insulation resistance
- Thermocouple tests/calibrations

Excitation System Electrical and Operational Tests

- Exciter rotor and stator winding resistance measurements
- Polarization Index measurements and Megger tests to determine condition of the exciter rotor and stator winding insulation
- Thermocouple tests/calibrations
- Diode checks - measurement of diode forward and reverse bias resistance and voltage drop; resistance of fuses; etc
- Operational checks on the AVR

The following Alternator visual inspections are often carried out as part of ongoing inspection and maintenance programs. These inspections, carried out during major outages with the Alternator removed from the Unit, can assess the condition of the stator, rotor and bearings. Items typically inspected during major outages are as follows:

<u>Stator Visual Inspection</u>

- Loose or damaged wedges;
- Loose or cracked or failed connectors;
- Dusting, greasing and other signs of movement of windings;
- Indication of arcing (hot spots); damaged laminations;
- Loose Core bolts;
- Signs of contamination / excessive dirt

<u>Rotor Visual Inspection</u>

- Signs of physical damage;
- Loose or cracked or failed connectors;
- Slot wedge migration and possible contact with retaining ring;
- Signs of overheating;
- Loose rotor wedges;
- Dye penetrant examinations and magnetic particle tests on forgings, retaining rings and fan components to detect fatigue cracks; ultrasonic examination of interior surfaces of the forging and retaining rings

<u>Bearings Visual Inspection</u>

- Assess general condition of the bearings
- Do the bearings require re-babbiting or machining?

HYDRO provided copies of its Gas Turbine daily, weekly, semi-annual, annual and 5 year inspection check lists as well as the 6 year P&C inspection check list. Most of these inspection check lists were dated 2003. There is essentially no reference to alternator and exciter tests or inspections on these lists. Copies of these lists are included in Appendix 5. In addition there are Alternator and Exciter tests and inspections listed in the O&M Manuals for each site. It is not obvious that any of these recommended tests and inspections is being carried out by HYDRO.

On a go-forward basis, it is recommended that a regular formal inspection and test program be established for the Alternator and its Excitation System and that some or all of the above listed tests and inspections are part of that program. The electrical tests should be conducted on an annual basis with major visual inspections on a 5 year basis. The test data and inspection information should be recorded and stored at a central location for easy access in the future. In addition, a specific group at HYDRO should be charged with the responsibility for conducting such tests and inspections.

5.3.6 Alternator/Excitation Recommendations Summary

- It is recommended that a series of electrical tests be carried out on the Alternator at the earliest opportunity to provide a snapshot on the current condition of the Alternator.

- In addition to the electrical tests noted above, it is recommended that the Alternator itself or as a minimum the rotor be physically removed from its enclosure and the visual inspections and electrical tests noted above be carried out. This detailed examination will clearly determine the condition of the Alternator and its components and the specific refurbishment work (if any) that must be carried out to ensure its ability to operate reliably for a further 15 years.
- The Curtiss-Wright Turbine-Alternator Manual (Book 3) recommends a minimum list of spare parts that should be carried for the Alternator and its Excitation System. It is recommended that the suggested list of spares be stocked at one central location for both the Hardwoods and Stephenville sites.
- On a go-forward basis, it is recommended that a regular (annually; semi-annually; etc) formal inspection and test program be established for the Alternator and its Excitation System and that some or all of the tests and inspections listed in sub-section 5.3.5 be part of that program.

5.3.7 Alternator/Exciter Enclosure

The alternator module is constructed of structural steel framing with a steel plate exterior cladding. The exterior coating was found to be in poor condition. Surface corrosion and flaking of the coating were noted in several locations on the exterior of the enclosure. We recommend that the exterior of the alternator enclosure be cleaned, prepared and recoated within the next two (2) years (Photo: HWD-027). The concrete foundation under the generator module was visually inspected and was found to be in acceptable condition with no visible cracking or significant deterioration. During the site inspection the alternator was operating in as a synchronous condenser. Therefore we were not able to carry out a visual inspection of the interior of the module.

The existing man doors in the alternator module do not have any windows. We recommend that windows be added to the doors for safety purposes. This will allow HYDRO site personnel to view the interior of the module before opening the door. This would be particularly helpful should there be a fire inside the alternator module.

5.4 FUEL OIL SYSTEM

5.4.1 Fuel Unloading and Storage

The Gas Generator Engine fuel is No. 2 diesel oil which is delivered to the Site by truck. Fuel storage comprises one storage tank with 14,000 bbl nominal capacity (2,225,000 litres) (Photo: HWD-028). At 50 MW, the plant will use about 16,000 L/hour, so one tank-full lasts approximately 5.5 days. The tank contained oil at the time of inspection, so only visual inspection of the exterior was carried out.

A fuel storage tank farm upgrade was carried out in 1996/97. Originally there were two tanks at the Hardwoods facility. During the upgrade, one tank was completely removed; the remaining tank was cleaned, repairs were carried out and the interior floor was recoated. The containment dyke was also modified as part of this upgrade project. A new section of dyke was added to reduce the size of the original containment area and the dyke was reshaped to meet the regulations for spill containment at the time. The existing tank was also lifted at this time and a new dyke liner was installed throughout the entire containment area. The existing tank exterior was recoated in 2000. One storage tank may present logistical problems related to temporary fuel supply when the single tank has to be drained for internal inspection in the future.

The tank was built to API Standard 650, and should be operated subject to API Standard 653 – Tank Inspection, Repair, Alteration and Reconstruction. This standard calls for periodic inspections and records of construction, inspections, and repairs. The frequency of inspections can be linked to a rate of corrosion or in the absence of measurements; the frequency of inspection must be less than every ten years.

No records, as required by API 653, have been provided by HYDRO to date. We recommend that HYDRO confirm that inspections have been carried out and inspections are properly documented. The tank has been in service since the up-grade in 1997. At that time, an internal inspection and checks on metal thickness should have been carried out and documented on file. From an external observation, the tank appears to be in generally good condition and should be serviceable for a further 15 years use.

The exterior coating of the fuel storage tank was found to be well faded and in marginal condition. In several locations surface corrosion and spot failures of the coating were noted. Peeling of the coating was also noted on the roof of the tank. Coating failure and corrosion was most notable on the stairs and handrail on the tank. Given the size and number of coating failures this is not an immediate concern. However, the exterior of the tank will like require recoating within the next five (5) to seven (7) years (Photos: HWD-029 & 030). However, the stairs and handrail will like require recoating within the next two (2) to three (3) years based on the current level of corrosion (Photo: HWD-031).

During the inspection it was noted that two of the stair treads on the tank were badly corroded and in need of replacement. As well, the hand rail on the top of the tank does not have a kickplate installed. Since these issues are safety related they should be addressed at the earliest opportunity. It was also noted during the site inspection that there was no grounding installed on this fuel storage tank.

The storage tank is fitted with a float and tape level gauge, a conductivity level switch, a differential pressure level transmitter, a temperature gauge. All instrumentation equipment appears to be in good working order.

The fuel oil containment dyke was found to be in generally good condition at the time of inspection. The dyke walls were found to be in good condition with adequate gravel and good grading. The containment dyke area was well lit with four (4) light standards and there was an eight foot high chain link fence surrounding the area that was in good condition. The bottom of the tank is elevated above the bottom of the dyke to prevent submergence in water and premature corrosion of the tank bottom.

It was noted that there was water in the containment dyke during the inspection. Hydro site personnel indicated that the water was removed from the dyke by placing a submersible pump inside the dyke and pumping it as required. HYDRO may wish to consider installing a sump, gravity feed drain pipe and manually operated valve to allow easier and more frequent draining of the containment dyke.

5.4.2 Fuel Forwarding

The function of the fuel forwarding module is to provide fuel at a positive and constant pressure to the gas generator engines for combustion. An inspection was made of the fuel forwarding equipment contained in a building adjacent to the Gas Turbine. The major equipment located inside the building consisted of the main pump and motor, the auxiliary fuel pump and motor, the electric fuel heater, fuel filters, pressure switches, control valves, regulator valve and the associated piping.

The pumps, valves and piping were checked for evidence of problems. Nothing significant was found and the equipment had a well cared for appearance. There is sufficient back-up pumping and valves to provide a low risk of failure to deliver fuel. However, there is only one fuel heater and a spare replacement element should be carried together with the necessary gaskets, etc. Nothing of this nature was noted in the inventory of spare parts.

All instrumentation appears to be in good working order.

5.4.3 Fuel Piping

The piping from the fuel unloading building to the storage tank is above ground. The condition of the piping system is good and should be reliable for a further 15 years of service.

The piping from the fuel storage tank to the fuel forwarding building is a combination of aboveground/underground and does not conform to current codes. HYDRO is currently replacing the underground sections of the piping with double-walled piping with vacuum monitoring. The interior pipe is 4 inch and the exterior pipe is 6 inch.

The piping from the fuel forwarding facility to the power plant is above ground and in cold weather the fuel temperature can be a problem for successful start-up. HYDRO personnel stated that they are planning to consider a properly-designed fuel temperature control system or electrically heat trace the above ground piping in 2007.

5.5 ELECTRICAL SYSTEMS

5.5.1 13.8kV Switchgear

The switchgear serves to isolate the plant and its related systems electrically from the grid when it is not running or is down for maintenance. The switchgear and associated protective relaying systems provide protection to equipment and personnel during abnormal loading or fault conditions.

Switchgear is subject to deterioration over time due to breaker contact wear, arcing damage and insulation breakdown. A typical switchgear installation includes integral instrumentation transformers, which are also subject to insulation degradation. While generator breakers are infrequently called upon to interrupt heavy or short-circuit loads, the recommendations of the manufacturer should be followed with respect to inspections and maintenance schedules.

Switchgear should be replaced when no longer supported by the manufacturer, parts availability wanes and safety of personnel or equipment potentially becomes compromised as a result.

The 15 KV 3000A metal-clad walk-in switchgear assembly houses the 13.8 KV alternator circuit breaker, potential and current transformers, and the 600V breakers for the station transformer. The alternator breaker is a withdrawable magnetic air type circuit breaker manufactured by Westinghouse. HYDRO provided a copy of a report on a condition assessment of the Hardwoods and Stephenville 15 kV Switchgear and outdoor Bus Duct carried out by Acres in 1995. It is our understanding that most of the recommendations outlined in that report have been carried out. There was a budget proposal in 1998 to replace the alternator circuit breaker and use the existing beaker as a system spare to serve both the Stephenville and Hardwoods site. According to the Hardwood site operator, the breaker was never replaced and it is the original installation at 1976. While a detailed inspection of the switchgear was not carried out in this study, the physical condition of the switchgear and the associated equipment appears to be in good condition. With the age of the breaker, it is recommended a thorough inspection and a complete over-hauled of the breaker should be carried out as soon as it is amiable. It may be prudent to consider replacing the existing breaker with a vacuum-type circuit breaker because it could be difficult to purchase direct replacement parts for magnetic air type circuit breakers. In addition, vacuum breakers require less maintenance.

The Cable entrance cubical for the switchgear is in a state of mess. The 600V power cable is mixed with the control and instrumentation cables. The only separation between the cables and the 600V power terminals is the plastic cover on the 600V terminals. Besides looking untidy, it is creating a safety hazard. For a temporary fix, it is suggested that dividers to be installed to separate the power cables from the control and instrumentation cables. Good house keeping should be applied to tidy up the control and instrument cables. For a long term solution, the power cable should be installed in a separate compartment from the control and instrumentation cables. If there is any sign of insulation deterioration, the cable should be replaced. Any conductor terminated into a spring type termination block should have a ferrule installed at the wire end to align with the terminal block. There were comments from the P&C electrician about DC Ground alarms. The DC ground may be caused by the insulation deterioration of the control and instrumentation cable or improper termination of the conductors. It would be impractical to replace all the control and instrumentation cables at one time but if there is a chance of replacing any equipment and device, consideration should be given to replace the cables with the equipment.

Another comment from the P&C electrician is that there is only one power supply feeding the protection and control devices for both turbines. It is impossible to carry on the maintenance for one turbine and keep the other turbine running. Consideration should be given to provide separate power sources to each turbine‘s protection and control systems. This will enable one of the turbines to be in service while working on the protection and control devices for the other turbine.

A regular maintenance program for the switchgear and its equipment should be followed. Attention should be paid to inspect the condition of the breaker contacts, check for arcing damage, check the operating mechanism of the breaker and conduct insulation tests for insulation breakdown.

HYDRO should apply infrared thermography to monitor temperatures and thermal patterns while equipment is running in full load to detect changes in temperature. Repair and/or replace any hot-spot area. Safety procedures must be observed during scanning because the enclosure doors will be opened for scanning.

5.5.2 13.8 kV/600 V Station Service Transformer

The 750 KVA, 14.4 KV-600V station transformer which is the original installation at 1975, is located inside an enclosed cubicle. Results of tests carried out on the transformer over the years were not available for review during the visit. With the age of the transformer, it is recommended a thorough inspection and a complete over-haul of the transformer and its accessories be performed as soon as possible. With regular maintenance, the transformer should be able to provide satisfactory service for the next 15 years.

The transformer and its accessories, such as the lightning arrestors, the surge capacitors and the cable connections should be part of a regular maintenance program. HYDRO could apply infrared thermography to monitor temperatures and thermal patterns while the transformer is running under load to detect changes in temperature. Repair and/or replace any hot-spot area. Safety procedures must be observed during scanning because the enclosure doors will be opened for scanning. The transformer insulation should be tested at regular intervals. Over heating and overloading of the transformer will shorten the life of the transformer.

5.5.3 13.8 kV Bus Duct

The 13.8 KV metal enclosed bus duct (Photo: HWD-032) connects the alternator phase bushings to the 13.8 kV alternator circuit breaker located in the 13.8 kV switchgear enclosure. The bus duct further connects the circuit breaker to the unit step-up transformers 13.8 kV bushings located in a low voltage termination box mounted on the transformer. The bus bar material is copper and the bus duct is enclosed.

The bus duct is also constructed of heavy gauge steel plate sections. These sections of duct are bolted together using butt joints (Photo: HWD-033 & 034). During our site inspection HYDRO personnel indicated that this bus duct regularly leaks and some times this water enters the high voltage switchgear building. This may also be one of the sources of leaks for the high voltage switchgear building noted in sub-section 5.7.6. In general the structure of the bus duct was found to be in acceptable condition.

Butt joints are very difficult to make watertight and are likely the source of the leaks noted by site personnel. It appears that attempts have been made in the past to seal these joints with a sealant, which was subsequently painted over. Sealant should not be relied upon as the primary method of sealing joints as it will crack and deteriorate over time. This is especially important at horizontal joints. Cracking of the paint and sealant was noted during the site inspection.

Given that the bus duct is leaking and water from these leaks can find its way onto the existing high voltage switchgear, we recommend that this problem be repaired as soon as possible. This bus duct could be made weather tight by applying hot applied rubberized asphalt roofing compound over the duct similar to how exterior HVAC ductwork is sealed commercially. As well, the bus duct could be covered with cladding used for exterior HVAC ductwork to make it weather tight. Both options are viable. The hot asphalt option is likely cheaper and easier, while the cladding option will allow easier removal and access to the bus duct in the future.

With regular maintenance, the bus duct should be able to provide satisfactory service for the next 15 years. Regular maintenance should include inspection for bus bar rusting and corrosion, insulator tracking and the physical appearance of the enclosure. The bolts at the joints should be re-torqued regularly. Infrared scanning of the bus bar, the joints and the terminations should be performed to identify hot-spots.

5.5.4 AC and DC Motor Control Centres

The motor control centres (MCC) provide protection and control for the auxiliary electrical devices for the gas turbine plant. There are two motor control centres - one for the 125V DC equipment and another for the 600V AC equipment. The MCC cabinets house the basic electro-mechanical devices such as circuit breakers, contactors and overload relays. The MCCs were supplied by Cutler Hammer. Eaton/Cutler Hammer or other electrical equipment distributors can supply compatible replacement parts or replacement kits for any MCC up-grades. The operating handles of the MCC are capable of padlocking. This feature should satisfy HYDRO's locking and tagging requirement.

Unless the operating philosophy of the motor control changes drastically, such as operating the motors with variable frequency drives (VFD), adding feedback monitoring and network interfaces that would require changes to the structure of the MCC wrappers (any changes to the MCC structure will require CSA re-certification), the existing MCC should not require to be replaced and should be capable of operation for a further 15 years.

In addition to regular inspection on the de-energized equipment, infrared thermography inspection should be performed on a regular basis with the equipment energized. Safety procedures must be observed during scanning because the enclosure doors will be opened for scanning.

5.5.5 DC System – Station Battery and Charger

The station DC system has to provide sufficient capacity to supply the various DC motors and DC powered protection and control systems.

Depending on the battery type, the station battery is subject to various forms of deterioration including: corrosion of posts, cables, hold-downs, and battery trays; cell damage due to severe discharge or overcharge conditions; high resistance connections; and reduced cell capacity. Routine maintenance will serve to detect and remedy these conditions, such that replacement is only required when the general condition deteriorates beyond the point that maintenance is ineffective or overall battery capacity no longer meets the plant requirements. Manufacturers typically specify a design life of 15 to 20 years for wet-cell type batteries, and recommend that the banks be replaced after this period of time.

Common charger and inverter failures include open or shorted rectifier diodes or deteriorated electrolytic capacitors. Replacement is a consideration if vendor support is no longer available, improved output characteristics are desired (i.e. reduced ripple, improved regulation) or the charger or inverter load changes considerably due to changes in the station.

The battery bank is located in a separate cubicle from the breaker cabinet. The 125V 1035 amp-hour VRLA bank for the Hardwoods Gas Turbine was installed in 2005. No leaks or cracks are visible and they are in good conditions. With regular maintenance, the batteries should be able to last for more than 15 years. The 125V charger is the original installation supplied by Gentac. While it is working satisfactory now, it should be replaced in the near future because of the vintage of the charger.

The current inverter was supplied by Pylon. It replaced the original unit on March, 2006 when the original unit failed. Under normal operating conditions, the inverter should be able to provide satisfactory service for the next 15 years.

5.5.6 Protection Relays and Synchronizer

The protective relaying systems provide protection to equipment and personnel during abnormal loading or fault conditions. Their functions must be sufficient to protect the generating unit against all harmful conditions that may develop and act quickly and appropriately to isolate the abnormal conditions from the system and the alternator. The synchronizing function is critical and requires accurate and reliable monitoring of voltage level, frequency and phase angle. It ensures bump less transition of the alternator to the on-line state, thereby minimizing machine stress and power system transients.

The measuring relays for the alternator protection system are electromechanical relays. For electromechanical relays, ageing of the moving surfaces (such as bearings and bushings for induction discs) due to corrosion or excessive wear can lead to failure of the relay. For measuring relays, ageing of components such as capacitors, resistors, coils and worn contacts are sources of failure. Ageing mechanisms include: corrosion and overheating of contacts; vibration on bearings; wear of bearing surfaces that have exceeded the number of design operations; and failure of insulation material in capacitors and other components due to ageing of the materials.

While a detailed alternator protection review and analysis is not within the scope of this study, a review comparing the existing protection functions with IEEE Std. C37.102-1995 IEEE Guide for AC Generator Protection is provided as follows:.

<u>IEEE recommendations:</u>

- Loss of excitation (40)
- Phase and ground fault (87G, 87GN, 51/59GN)
- Field fault (64F)
- Unbalanced current (negative sequence) (46)
- Over and under-voltage (59, 27)
- Over and under frequency (81)
- Stator thermal (49)
- System back-up (51V)
- Alternator turn to turn fault (61)
- Voltage balance (60)

<u>Existing Protection Functions:</u>

- Loss of excitation (40)
- Phase and ground fault (87G, 64G)
- Field fault (64F)
- Unbalanced current (negative sequence) (46)

- Over and under-voltage (59G, 27G)
- Over and under frequency (81)
- Stator thermal (49)
- System back-up (51V)

The existing protection provides adequate basic protection functions to protect the alternator. Compared with the IEEE Standard, the functions that are missing are the generator turn to turn protection (61) and the voltage balance relay (60). An alternator turn to turn fault is difficult to detect. Alternator differential relay will provide protection for alternator internal faults. Depending on the setting sensitivity of the alternator differential relay, it will provide some degree of turn to turn fault protection. The function of the 60 relay is to block the mis-operation of the relays using voltage as a restrain source. There will be costs to incorporate these two functions into the existing protection system. HYDRO's protection design engineer may want to review the scheme and decide whether the level of reduced risk will warrant the level of expenditure required.

Although the existing relays could provide adequate protection, the availability of any direct replacement of the electromechanical relays will be limited. Unless HYDRO has spare relays stocked in their system, it will be difficult or even impossible to obtain direct replacement relays from the manufacturers. The option of replacing the entire protection panel with digital protection relays should be considered because of the ageing considerations of the electromechanical relays, the unavailability of the replacement relays and the increased protection obtained through the multiplicity of advanced functions available in today's digital relays at relatively low cost.

The automatic synchronizing function is provided by the Bailey DCS system. The sync-check relay, PRS-250 is provided by Basler Electric. The design of the sync-check relay has not been changed for the last 15-20 years and is expected to remain that way unless a parts availability issue forces Basler to make a component change.

Historically, the failure rate of electromechanical relays is low (with good maintenance, some of the relays are still in service after 40 years or more) but some of the relay components will age and will fail eventually. The replacement parts and the skilled technicians that are knowledgeable enough to fix these relays are getting harder and harder to find. We suggest that a protection replacement budget and protection modification program should be prepared for the Facility. Replace the relays for the Facility when the opportunity arrives and possibly keep the replaced relays as spare for the other Facility for direct replacement.

With today's technology, one multifunctional digital protection relay could replace several electro-mechanical relays to provide the same protection functions. The GE Multilin Generator Protection Relay replaces the following existing protection functions – 40, 64,87G, 46,59,27,81, 49 and 51V (refer to relay function numbers above). A cost estimate has been provided for one multi-functional digital generator protection relay. If HYDRO's protection philosophy requires additional relays for backup or for another redundant scheme, the cost estimate will increase accordingly. In the meantime, considering the age of the relays and the non fail-safe design of the electromechanical relays, it may be prudent to test the existing relays in a 2 or 3-year cycle rather than the 6-year cycle as recommended in the HYDRO maintenance program.

5.5.7 15 kV Power Cable

The power cables associated with the 750 kVA station service transformer are cross-linked polyethylene (XLPE) insulated cables.

Medium voltage XLPE insulated cables were first installed in the late 1960's. The cable manufacturers and utilities expected the cables to perform reliably for 20-30 years. History has shown that the service life of some of these early cables was far shorter than expected. Many cables failed after only 10-15 years in service. It was later discovered that voids and contamination in the semi-conducting shields, as well as other design and manufacturing deficiencies, led to voltage stress concentrations within the cables. The elevated voltage stress, combined with moisture ingress into the cable structure created what are known today as water trees. These microscopic cavities degraded the insulation over time, ultimately causing the cable to fail. To reduce water tree growth, a special engineered insulating material designed to limit water tree growth called XLP-TR was commercialized in the early 1980's and has been performing reliably in service for over 20 years. Furthermore, the design, manufacturing practice and quality control of power cables have improved drastically within the last 20 years. The design life for the XLPE insulated cable is 20-25 years. The design life for XLP-TR (trees retarded) insulated cables is 30 years or more.

It is our understanding that the 15 kV power cables in the Plant were the original installations that dated back to 1975. The failure rate for power cables installed before early 1980s is high. Our recommendation is to replace the 15 kV power cables installed during 1975 with XLP-TR type insulated cables during the next major Plant shut down. For a 13.8 KV system, the power cables should be shielded and terminated with stress cones.

5.5.8 Motors

Properly selected and installed motors are capable of operating for many years with a reasonably small amount of maintenance. Routine maintenance should include inspection for dirt, corrosion, heat, noise, vibration and brush conditions; lubrication of bearings; measuring and trending of the winding insulation.

Motors located inside the buildings seem to be in good physical conditions. All motors should be cleaned, check for signs of corrosion, perform internal inspection, and open the conduit box to check for deteriorating insulation or corroded terminals. Insulation resistance (Megger) test and Polarization Index test should be incorporated into the maintenance program. Any damage parts discovered during inspection should be repaired and rebuilt. Well maintained motors should provide satisfactory service for the next 15 years.

5.5.9 Emergency Backup Diesel Generator

An emergency backup diesel generating unit was installed in 2005. The diesel generator is a self contained package consisting of control panel, battery charger, etc. The 40 kW 600 AC volt diesel generator starts automatically on loss of the AC station service supply to the Gas Turbine and supplies power to a backup battery charger which in turn ensures the integrity of the 125 Vdc supply to the Gas Turbine for protection and control purposes. The diesel generator also provides a backup AC supply for one of the air compressors. The diesel generator is in excellent condition.

5.6 CONTROL AND INSTRUMENTATION SYSTEMS

5.6.1 Control Module

The gas turbine control module features an ELSAG Bailey INFI 90 DCS installed in 1997 to replace a mainly electromechanical relay control system. The DCS system incorporates three subsystem hot-swappable controllers with redundant backup controllers. The DCS internal network utilizes a redundant communication module. The operator interface uses an industrial PC running PCV and QNX software. The PC is connected to a CRT monitor which displays system graphics and to a keyboard for operator input. A communication link connects the PC to a SCADA system which allows remote control and monitoring of the gas turbine from the Energy Control Center in St. John’s, Newfoundland.

There have been some failures recently of input channels at Stephenville. There is very little in the way of replacement cards for the Bailey system other than some sequence of events cards. ABB still sells all of the Infi 90 cards and will support them for an additional 10 years once the product has been discontinued in a few more years. In addition, newer technology is available that will directly replace the older technology and use the same footprint. Stantec recommends stocking spares for all card types.

The interface computer, an industrial PC has been functioning well with only one lock-up recorded in the station log. The interface computer is an older vintage and as such has very little memory capacity and will not run today’s software. There is significant risk in not replacing the existing PC since it is older technology and does not have a ready availability of parts. ABB has issued a quotation to HYDRO P&C (copied to Stantec) for a new PC with the latest PCV and QNX software. The new PC will also give HYDRO the ability to do more extensive trending. Stantec strongly recommends the PC and software upgrade be implemented.

The power supply system for the DCS is obsolete. Stantec recommends replacing the power supply system in order to extend the life of the control system out 15 years. ABB has provided a quotation to HYDRO P&C (copied to Neill and Gunter) for a new power supply.

Conditions in the control room were quite humid at the time of the site visit. In addition to the humidity, there are also several sources of heat in the room. Heat and humidity are known to speed the deterioration of electronic components. Stantec recommends that the air conditioning unit for the control module be checked to ensure it is operating properly.

5.6.2 Interposing Relays

In August 2006 P&C staff discovered a problem with the control system design at the Stephenville site which also exists at the Hardwoods site. There are at least 8 relays with contacts which are not rated for the DC current which is being interrupted. The problem was detected when welded contacts were found on the relay which controls the fuel recirculation valve at the Stephenville site. Pitting and carbon deposits may be forming on some or all of these relay contacts resulting in increased switch bounce and high impedance contacts. High impedance contacts would cause a reduction of power to the device being controlled. Partial welding would result in late break operation. The overall result of using the incorrect relays could be inconsistent control, possibly with shutdowns or non-starts. P&C staff has begun to install interposing relays at Hardwoods. The final connections will be made when the units can be shut down long enough to do the work.

5.6.3 Vibration Monitoring

The existing vibration monitor by IRD was installed in 1975. The monitor appeared to be functioning well at the time of start up during the site visit.

There have been instances in the past when GGA would not start due to vibration problems. In April 2000, GGA was sent to Scotland for this problem to be repaired. The station log does not indicate any vibration problems since then. Vibrations seem to be worse on cold days, when the machine is cold and has not been cycled for a while. Stantec would recommend more frequent cycling in the winter months.

Operations staff and P&C are of the opinion that the vibration monitoring equipment needs to be replaced. In November 2005, some of the vibration cards burnt out. The equipment is obsolete and there will likely be more failures in the next 15 years. According to P&C staff, HYDRO has an approved capital budget item to replace the existing vibration monitors at both sites in 2008. The existing transducers are functioning well but are obsolete. They are still available on the market, but Stantec recommends replacing these with newer accelerometers. It would be also be advisable to purchase spares.

5.6.4 Temperature Monitoring

Temperature monitoring is an integral part of the DCS system whereby critical temperatures are brought into the DCS either as analog inputs from RTD's and thermocouples or as discrete signals from temperature switches. Bearings, windings, glycol, oil, fuel, and air are some of the quantities being measured. Critical temperatures can cause alarming, power limiting or unit shutdown as appropriate.

The thermocouples should use terminal blocks designed for thermocouples. P&C has indicated that proper terminal blocks are not being used in all cases. Stantec was not able to open the terminal boxes to examine. NLH should replace the terminal blocks on an upcoming planned maintenance.

Temperature element failures are likely to occur over the next 15 years. One approach which HYDRO could take with regards to thermocouple and RTD maintenance is to replace the elements on each sub-system at the time of a major overhaul. Elements which can be easily changed and have no shutdown initiation can be replaced as they fail. Dual element thermocouples are likely not a cause for concern since the second element is available when the first one fails. Existing spares should be reviewed.

Temperature switches have not shown any failures at Hardwoods. Exact replacements will not likely be available over the next 15 years, but it is very easy to source an equivalent switch with a compatible temperature range. Temperature switches are dry contact devices so there is no issue with supply voltage level. Installation detail will not likely be an issue as the switches are normally surface-mounted or mounted with a standard pipe size and thread type. Switch size should not be a problem since instrumentation generally shrinks in size over the years and will therefore fit in the footprint of the device being replaced.

5.6.5 Instrument Calibration

Stantec could not find any evidence that transmitters and switches are being periodically calibrated. Operations could not recall these activities being done. Stantec recommends routine calibrations of all instruments. Initially all instruments should be calibrated and the frequency of recheck should be dependent on the stability of the instrument. Non stable instruments should be replaced.

5.6.6 Control Valves

There are several control valves including a temperature regulating valve in the glycol system, a pressure controlled valve in the lube oil system, and control valves in the fuel system. These valves are original equipment with the exception of the motorized valve at the fuel tank. As such, it may be difficult to get spare parts and support, although the station logs have indicated replacing internals in some of these valves. NLH should examine the design conditions for these valves to determine if the conditions can be met today in a package that is a direct replacement. If not, some redesign of piping will be required should a valve have to be replaced. This is best determined in advance so a plan can be generated and sufficient spares stocked. Stantec recommends one spare for each of the original equipment control valves.

Anti-Icing Valve

There have been several incidents of shutdown due to anti-ice valve failure. Stantec recommends at least making the response to an anti-ice valve operation a power limited condition rather than a full shutdown. The logic can likely accommodate this change.

Fuel Tank Motorized Valve

The motorized valve on the fuel tank is new and works well with one exception. There appears to be a deficiency in the logic in which the valve will not open until a certain time delay after an engine has successfully completed its start up sequence. Once the engine has started it is consuming fuel oil while the motorized valve is still closed. Eventually it uses all of the fuel in the line between the engine and the fuel tank, and the unit shuts down. Logic changes appear to be in order to correct this problem.

5.6.7 Clutch Proximity Switch

A proximity switch in the clutch detects the engagement of the clutch between the turbine and the alternator. There have been failures of the proximity switch in the past and there was another failure during this site condition study. There appears to be a physical interference issue between the clutch mechanism and the proximity switch when the clutch engages. Refer to sub-section 5.2.6 for further details. As a side issue, it was noted that the gas turbine unit is coming to a complete shutdown after a time delay when engagement is not detected. Stantec recommends that the logic be investigated to see if a complete shutdown can be avoided. It may be feasible to leave the machine in sync-condense mode.

5.6.8 Fuel Temperature

There have been failed light-offs due to cold fuel. Stantec supports Hydro's recommendation to put the cold fuel through a recirculation period to heat the fuel prior to light off during cold winter days. This recirculation operation could be left as a manual operation or programmed into the logic to occur based on a given ambient temperature and cold machine starts.

The fuel valve start position has been adjusted at times due to ambient temperature to achieve light off. Perhaps this adjustment can be eliminated with the recirculation modification discussed above.

There is an additional issue with fuel temperature control. The temperature sensing element for the fuel shutdown circuit is located directly in the fuel heater, whereas the sensing element for fuel temperature control is located in a pipe several feet away. Stantec recommends that the two temperature sensing elements be located adjacent to one another to allow the control system to do its job before the shutdown system kicks in.

5.6.9 Fuel Storage Tank Level Switch

The Hardwoods site does not have a low level cutout switch on the storage tank, whereas the Stephenville site does have cutout switches on its storage tanks. Stantec recommends the installation of a low level cut out switch to prevent running the pumps dry or pumping out tank bottoms in the event of the level transmitter failing. NLH should examine its current logic to determine if the existing risk of using a transmitter only is acceptable.

5.6.10 Fuel Storage Tank Wiring Conduits

There are a few holes in the liquid tight conduit around the Motor Operated valve and junction box. There is also a separated PVC conduit joint in the conduit between the storage tank and the fuel unloading building. These should be fixed to prevent further water ingress.

5.6.11 Remote Control and Monitoring

Remote control and monitoring of the Hardwoods Gas Turbine at the Energy Control Centre (ECC) in St. John’s is accomplished through a SCADA system interface to the DCS. The SCADA system is not part of the Condition Assessment Study scope.

P&C personnel have indicated that future upgrades are being considered. In particular, data transferred from the Gas Turbine sites to ECC could be expanded and stored on a PI historian at ECC. According to P&C personnel, HYDRO has a central group that deals with SCADA maintenance and upgrades.

5.6.12 Junction Boxes

One of the junction boxes has some corroded terminals on the outside of GGA. With the alternator operating as a synchronous condenser at the time, Stantec did not get an opportunity to look inside this box, but it was pointed out by the turbine operator. Of course, all corroded terminals should be replaced. The junction box covers are in general quite water tight due to the large number of bolts holding the covers on. NLH has begun putting an extra stainless steel cover over some boxes where there have been water problems. These are working well.

The main junction box on the outside of the control module building is in a state of disarray. Wire ducts are overfilled (Photos: HWD-035 & 036). Cables are hanging this way and that. Normal housekeeping practices were not followed during the rewiring of these cables for the

DCS installation. Stantec suggests that the congestion and housekeeping issues be corrected to enable trouble shooting. Since there have been a few examples of failed cables, NLH may want to consider replacing all cabling from this box to the field.

Another issue in this junction box is the presence of the 600V cabling. The terminals have been guarded with Plexiglas to prevent accidental contact by service personnel. NLH should find a new location for the 600V terminals should it decided to mount a re-cabling effort.

Both turbine units still have the original on-engine electrical junction boxes. It is recommended that these boxes be moved off-engine, to isolate the terminations from engine vibration and heat.

5.6.13 General Comments

There is no guarantee that any particular instrumentation component will last another 15 years without repair or replacement. However, most of the instrumentation will have suitable replacements.

It would be a beneficial project for HYDRO to create a specification sheet for each piece of instrumentation. Nameplate data, set points, ranges of operation, flange rating, face to face dimensions, etc, could be recorded. Where nameplates and other information is unreadable or unavailable, the exercise of creating the spec sheets will require a bit of research but could be done under non-breakdown conditions.

Having this information available electronically will make sourcing of suitable replacement instruments easier. Identifying replacements could be done in advance to build a spares inventory. The spec sheets could identify several instruments which could use a common spare. Maintenance notes could be added to the spec sheets to track repairs and calibration.

Some of the more complicated retrofits, such as a control valve which requires piping modifications, could be done on a project basis when the valve nears the end of its serviceability.

Stantec is not aware of the program used by HYDRO for the routine calibrations or testing of switches. HYDRO should confirm that the current set points of all instrumentation are in line with manufacturer's original operational design set points. Further, HYDRO should confirm that all instrumentation is functioning properly.

Spares should be stocked for each type of instrumentation device when delivery lead times are long.

5.7 BUILDINGS

5.7.1 Control Building

The existing gas turbine control building is a single story prefabricated and packaged steel structure supported by cast-in-place concrete foundations. The exterior building envelop consists of heavy gauge steel plate and roofing. The exterior coating on the building was found to be in poor condition. Surface corrosion and coating failures were noted in several locations on the walls and roof of the building. Based on the level of corrosion we recommend that the exterior of this building be cleaned, prepared and recoated within the next two (2) to five (5) years (Photo: HWD-037).

The structural steel framing for this building was not visible from the interior of the building. Therefore, no structural inspection was carried on the interior of this building. The concrete foundation was visually inspected and no significant cracking or deterioration was noted.

Water stains on the ceiling tiles inside the building were noted in two locations, indicating roof leaks in the past. A visual inspection of the roof revealed that there are lap joints in the roof panels approximately every four feet. As well, it appears that the joints in the roof panels have been coated in the past in an attempt to seal them. Lap joints are very hard to make watertight. This roof is also flat making it even harder to make a watertight joint at these locations. Given the past leaks, difficulty making watertight joints with this type of roof and the equipment housed inside the building, we recommend that a new sloped metal roof be installed over the existing roof (Photo: HWD-038).

5.7.2 Fuel Unloading Building

The existing fuel unloading building (Photo: HWD-039) is a single-story prefabricated structure located adjacent to the fuel oil containment dyke. The exterior of the building consists of sheet metal siding and roofing with sheet metal liner panels on the interior of the building. The building is supported by cast-in-place concrete foundations and has a concrete slab on grade. The building is ventilated by a single exhaust fan and a supply louvre.

The steel structure was not visible during our site assessment. However, the interior ceiling and wall liner panels are in good condition and there are no signs of corrosion or water staining. This indicates that there has been limited water leakage and the structure of the building is likely to be in good condition.

As part of this assessment we also reviewed the condition of the existing concrete slab on grade. The slab on grade was found to be in generally good condition with minor shrinkage cracking in the floor slab. There were no concrete containment curbs in this building. Therefore, should a pipe or pump leak inside the building, there is no way to contain the spill and this will likely result in a fuel oil spill.

The exterior cladding on the building was found to be in generally good condition with only some minor corrosion noted along the bottom of the wall panels. The roof however was found to have a significant amount of corrosion and will likely require replacement within the next two (2) years (Photo: HWD-040).

The existing concrete dyke at the off-loading station is in good condition with no visible cracking. However, the timber posts and guard rail protecting the concrete dyke and piping was in very poor condition and in need of replacement (Photo: HWD-042). It was noted that the area surrounding the concrete off-loading dyke was just gravel (Photo: HWD-041). We recommend that this area be paved to help contain and facilitate clean-up of any minor spills that may occur when the off-loading hose of the delivery truck is being hooked or unhooked to the oil transfer system.

5.7.3 Fuel Forwarding Building

The existing fuel forwarding building (Photo: HWD-043) is a single-story prefabricated structure. The exterior of the building consists of sheet metal siding and roofing with sheet metal liner panels on the interior of the building. The building is supported by cast-in-place concrete foundations and has a concrete slab on grade. The building is ventilated by a single exhaust fan and supply louvre.

The steel structure was not visible during our site assessment. However, the interior ceiling and wall liner panels are in good condition and there are no signs of corrosion or water staining. This indicates that there has been limited water leakage and the structure of the building is likely to be in good condition.

As part of this assessment we also reviewed the condition of the existing concrete slab on grade. The slab on grade was found to be in generally good condition. While there are no concrete containment curbs in this building, there is a floor trench inside the building running parallel to the perimeter walls that collects all spills and transfers the fluid via an underground drain piping system to a sump pit that is fitted with a level alarm. The underground piping system from the floor drains to the sump was replaced 2 years ago.

The exterior cladding on the building was found to be in generally good condition with only some minor corrosion noted along the bottom of the wall panels on the highway side of the building. Surface corrosion was noted on the roof in several locations. We recommend that the roof be cleaned, corrosion removed and repainted within the next 2 years (Photo: HWD-044).

The timber posts and guard rail protecting this building were found to be in very poor condition and in need of replacement (Photo: HWD-045).

5.7.4 Auxiliary Module Building

The existing auxiliary building is a single-story prefabricated structure. The exterior of the building consists of sheet metal siding and roofing with sheet metal liner panels on the interior of the building. The building is supported by cast-in-place concrete foundations and has a concrete slab on grade. It appears that the original building was expanded in the past to include the current compressor room.

The exterior cladding on the building was found to be in generally good condition. Surface corrosion was noted on the roof in several locations. We recommend that the roof be cleaned, corrosion removed and repainted within the 2 years (Photo: HWD-046).

The steel structure was not visible during our site assessment. However, the interior ceiling and wall liner panels are in good condition and there are no signs of corrosion or water staining. This indicates that there has been limited water leakage and the structure of the building is likely to be in good condition. We also reviewed the condition of the existing concrete slab on grade. The slab on grade was found to be in generally good condition.

5.7.5 Maintenance and Parts Storage Building

The existing maintenance and parts storage building (Photo: HWD-047) is a single-story prefabricated structure. The exterior of the building consists of sheet metal siding and roofing with sheet metal liner panels on the interior of the building. The building is supported by cast-in-place concrete foundations and has a concrete slab on grade.

The exterior cladding on the building was found to be in generally good condition. It appears that the siding and windows on the front of the building have been repainted in the last couple of years. The window located at the rear of the building requires painting and corrosion was noted at the bottom of the wall panels. Surface corrosion was noted on the roof in several locations. We recommend that the roof be cleaned, corrosion removed and repainted within the next two (2) years.

The steel structure was not visible during our site assessment. However, the interior ceiling and wall liner panels are in good condition and there are no signs of corrosion damage or water staining. This indicates that there has been limited water leakage and the structure of the building is likely to be in good condition. We also reviewed the condition of the existing concrete slab on grade. The slab on grade was found to be in generally good condition.

5.7.6 High Voltage Switchgear Building

The existing high voltage switchgear building (Photo: HWD-032) is a prefabricated and packaged building. This building is constructed of structural steel with heavy gauge steel plate cladding and roofing. The building is supported by cast in place concrete foundations. No significant cracking or deterioration was noted in the foundation during the visual inspection. The majority of the interior of this building is filled with high voltage switchgear and a large portion of the structure could not be inspected.

During the site inspection surface corrosion and coating failure was noted in several locations on the exterior as well as the interior of the building. Based on the level of corrosion we recommend that this building be recoated within the next five (5) years.

During the site inspection HYDRO site personnel informed Neill and Gunter that they have had leaks in this building in the past. They also indicated that they have had trouble determining the source of the leak and repairing it. The roof is constructed of heavy gauge steel plate which is simply lapped at the joints. It is very difficult to make a watertight seal with this type of joint. We therefore recommend that a new roofing system, such as a modified bitumen roofing membrane, be applied with hot asphalt directly over the existing roof. This new roof membrane will be a large improvement over the existing roofing.

5.7.7 Emergency Back-up Diesel Generator Building

The existing diesel generator building is a single-story structure that is approximate 150 square feet in size. The exterior of the building consists of vertical sheet metal siding and asphalt shingle roofing. The building is supported by cast-in-place concrete foundations and has a concrete slab on grade. For oil containment, the building has a floor trench that is piped underground to the same sump noted in sub-section 5.7.3 for the Fuel Forwarding Building. The interior of the building is finished with painted plywood.

The exterior cladding, roofing and doors on the building were found to be in good condition and no deterioration or corrosion was noted. The concrete slab on grade and interior plywood finishes were also found to be in good condition. An exhaust fan and louvre have also been installed to provide ventilation for the building.

It was noted that in one corner of the building the bottom one to two inches of the sheet metal siding was buried under the crushed stone gravel surrounding the building. We recommend that this be remedied so that the sheet metal siding is no longer buried. This will help prevent water migration into the building and premature corrosion of the cladding.

5.7.8 General Comments

Only visual inspections were carried out as part of this assessment. Not all structural components were visible or accessible at the time of inspection. No non-destructive or destructive testing was carried out on any of the structures noted above as part of the inspection. Therefore, this assessment should not be considered an exhaustive inspection of all civil/structural components. As well, it is important to note that no detailed analysis was completed as part of this assessment to determine the adequacy of different structures for their purpose.

5.8 ENVIRONMENTAL

The Condition Assessment Study addressed several environmental issues as they relate to the Hardwoods site, specifically soils contamination and air emissions.

Soil Contamination

A review of several environmental reports provided by HYDRO indicates there have been a number of documented spills and leaks of petroleum products at the Hardwoods site over the past 30 years. The petroleum products include #2 diesel fuel, lubricating oils, transformer and capacitor oils. These spills and leaks resulted in soil contamination at various locations including the diesel fuel bulk storage tank area and the gas turbine / terminal station area. The following are a few examples of recorded spills and leaks:

- In 1978 a spill of approximately 78,000 Litres of diesel fuel resulted from a sump pit near the gas turbine overflowing when a valve was left open. The contaminated soils were cleaned to the satisfaction of the Department of the Environment.
- In 1991 a spill of approximately 1,600 Litres of bearing oil resulted from a sump pit near the gas turbine overflowing.
- In 1991 a spill of approximately 1,200 Litres of lubrication oil resulted from a pipeline failure and subsequent sump pit overflow.
- In 1994 a spill of approximately 7,000 Litres of diesel fuel resulted from a rupture in the pipeline leading from one of the two bulk storage tanks. At the time, the dyke surrounding the tank was found inadequate to contain the spilled fuel. The contaminated soils were cleaned to the satisfaction of the Department of the Environment. In 1997, the storage tank was removed from the site, the dyke containment ability was increased and a new HDPE liner was installed beneath the remaining tank and around the dyke walls. The remaining storage tank was inspected and found to be in good condition. Refer to section 5.4 for further details on the fuel storage tank area and the remedial work carried out.
- There are also recorded instances of a transformer leak (1.2 Litres) and a PCB oil leak (2 Litres) when PCB's were used in capacitor banks. In recent years, the PCB capacitors have been phased out and replaced with components that meet regulatory requirements.

While these spills and leaks were cleaned to the satisfaction of the Department of Environment, impacts to the soils are still being encountered at various locations throughout the site. Since 1999, HYDRO has initiated a number of environmental studies to investigate these impacts. These studies include:

- AGRA Phase I Environmental Site Assessment in 2000
- AGRA Limited Phase II Environmental Site Assessment in 2001
- Jacques Whitford Tier II Risk Assessment in 2002.

The Jacques Whitford Study concluded that petroleum hydrocarbons are present in the surface soil and groundwater at the site but do not appear to be migrating off the site. In 2003, the

Newfoundland and Labrador Department of Environment in response to the Jacques Whitford Report issued a Letter of Closure stating that “the Department is satisfied, at this point in time, that the stated level of contamination remaining on the property, in the area addressed by the Report, does not pose an unacceptable risk to human health and the environment”. The Department issued two stipulations (i) workers engaged in future sub-surface excavations on site must be made aware of the potential risks of exposure to the remaining contamination and (ii) the on-site water supply shall not be used as a drinking water source.

The Study did not take an exhaustive look at environmental issues at the Hardwoods site. The issue of soil contamination is noted in this Report for the express purpose of making the reader aware that such conditions exist at the Hardwoods site and any significant work carried out at the site, as a follow-up to this Report, depending on the nature of that work, could involve costs for soil remediation.

Air Emissions

The gas turbines produce air emissions related to the combustion of diesel oil. The exhaust emissions are not filtered or treated. There is no Continuous Emissions Monitor System (CEMS) on either exhaust stack. The various HYDRO inspection check lists included in Appendix 5, do not list exhaust stack emission manual sampling as an activity. Data on stack(s) emissions testing that may have been conducted by HYDRO in the past was not available for review.

Exhaust emissions from the gas turbine fall under Newfoundland and Labrador Regulation 39/04, Air Pollution and Control Regulations (O.C. 2004-232). The Regulations list limits on the concentration of air contaminants due to all emitting sources. The concentrations are defined by periods of time during which the concentrations exist. It would appear that the present operational mode of the gas turbine, as predominately synchronous condenser operation, would be within the criteria listed in the Regulations. If the predominant operational mode in the future is generation on a somewhat continuous basis, HYDRO should be aware of the potential application of the air contaminant limits in the Regulations.

The Regulations state that an owner or operator who installs a new or modified emission source shall employ the best available control technology with respect to air emissions. This requirement however does not apply to parts replacement but would likely apply to the installation of a new gas turbine.

The Study did not take an exhaustive look at air emission issues at the Hardwoods site. The issue of air emissions is noted in this Report for the express purpose of making the reader aware that any future generation operational mode changes or significant work carried out at the site, as a follow-up to this Report, depending on the nature of that work could involve the application of the criteria in the Regulations.

6.0 STEPHENVILLE GAS TURBINE FACILITY CONDITION ASSESSMENT

6.1 GENERAL

This Section documents Stantec's observations and comments on the condition of equipment and structures at the Stephenville Gas Turbine Facility. These comments are based on observations during the site visit on July 17/18, 2007, discussions with HYDRO staff and a review of documentation provided by HYDRO. Photographs taken during the site visit are included in Appendix 13. The Facility was broken down into the following areas for the condition assessment study:

- Gas Generators/Power Turbines and Auxiliary Systems
- Alternator/Excitation System
- Fuel Oil System
- Electrical Systems
- Control & Instrumentation Systems
- Buildings

The Section contains a number of recommendations on refurbishment work that HYDRO should consider in order to provide for the reliable operation of the Facility (Photo: SVL-001) for a further 15 years. **The recommendations and associated costs are summarized in Appendix 6.**

6.2 GAS GENERATORS/POWER TURBINES AND AUXILIARY SYSTEMS

6.2.1 Rolls Royce Olympus C Gas Generator Engines A & B

The Gas Turbine consists of two Rolls Royce Olympus C, 25 MW Gas Generator Engines (A and B) fired on #2 Diesel Oil, each driving a Curtiss Wright Power Turbine equipped with a SSS clutch. Each Gas Generator Engine has an air intake structure and each power turbine has an exhaust stack. New Olympus C Gas Generator Engines are no longer available from Rolls Royce. At the present time there are approximately 14 Olympus C Gas Generator Engine assemblies available in the market. In addition to the refurbishment of the existing Gas Generator Engines as recommended herein and in line with HYDRO's plans to keep the Gas Turbines at both sites operational for a further 15 years, it may be advantageous for HYDRO to consider obtaining a whole spare engine assembly as eventually all the spare Olympus C units will be scrapped.

The Olympus "C" type 2022 gas generator is a straight flow tubo-jet employing axial flow compressors driven by an axial flow turbine. A diagram (Figure 2-3) illustrating a cross-sectional view of the Olympus C Gas Generator is included in Appendix 4 to illustrate the various components comprising the Gas Generator. The combustion system uses eight combustors each with a burner contained in an annular outer casing. The eight combustion chambers are arranged equidistant around the turbine numbered from the top clockwise when viewed from the rear. An external air compressor system provides air to the starter motors. A Woodward Electronic Governor controls fuel flow. Further details on the Gas Generator auxiliary equipment can be found in sub-section 5.2.2.

Provision is made for heating the compressor entry guide vanes, nose fairing and the leading edges of the air intake casing during adverse weather conditions. The heating medium is air tapped from the #6 vane of the compressor casing and conveyed through a pipe to an electrically operated anti-icing hot air valve.

The lubricating oil system comprises an external tank that contains a heater system and a cooler that is cooled by means of the incoming fuel to the turbine combustors. The remainder of the system comprises pumps, level control system and oil delivery temperature control system. The return oil is pumped through a micro filter back to the reservoir tank.

A vibration pick-up is mounted on the gas generator casing flange, and it has a frequency range of 20-400cps. The signal is modified to read amplitude peak to peak and the system includes for alarm and trip points at preset levels.

Rolls Royce Olympus C Gas Generator Engine A (S/N 202204) externally appears to be in fair condition, above average for the total time in service since installation in 1975. Significant corrosion and depletion of the blade exterior coatings was noted. A fibreoptic borescope inspection of one (1) combustor assembly in the 7:00 position, revealed no major unserviceable conditions to all visible engine internal components. Unit hot gas path general condition is commensurate with total time since new. Inlet air system deficiencies, allowing particulate such as rust to form and be ingested by the engine, have resulted in significant abrasive damage to the Compressor first stage blading, inlet bulletnose assembly and Compressor front frame inlet guide vanes.

The Gas Generator Engine A auxiliary systems appear to be in serviceable condition - oil supply, scavenge, starting, ignition, cooling air, fuel delivery and vibration monitoring systems. The on-engine controls appear to be in serviceable condition - speed indication, temperature sensors and Woodward speed governor.

Gas Generator Engine A has never been overhauled, and appears to be in fair condition. Should HYDRO choose to have the complete package refurbished and operate for an additional 15 years, it is recommended that this engine assembly be removed, disassembled to allow for detailed internal inspection and major refurbishment as required.

Rolls Royce Olympus C Gas Generator Engine B (S/N 202224) externally also appears to be in very good condition, above average for the time in service since last overhaul. No exterior corrosion was noted, nor depletion of the blade exterior coatings. A fibreoptic borescope inspection of one (1) combustor assembly in the 7:00 position, revealed no unserviceable conditions to all visible engine internal components. Inlet air system deficiencies allowing particulate such as rust to form and be ingested by the engine have resulted in minor abrasive damage to the compressor first stage blading.

The Gas Generator Engine B auxiliary systems appear to be in serviceable condition - oil supply, scavenge, starting, ignition, cooling air, fuel delivery and vibration monitoring systems. The on-engine controls appear to be in serviceable condition - speed indication, temperature sensors and Woodward speed governor.

Gas Generator Engine B was last overhauled in year 2000, and appears to be in good condition. Should HYDRO choose to have the complete package refurbished and operate for an additional 15 years, it is recommended that this engine assembly be removed and disassembled to allow for detailed internal inspection and refurbishment as required.

It is suggested that compressor washing be conducted every 6 months. Crank soak washing is recommended over fired wash. A recommended cleansing agent – B&B 3100 – should be diluted with distilled or de-ionized water. Distilled or de-ionized water should also be used for the follow-on rinse.

HYDRO provided a copy of Inspection Report prepared by ALBA POWER reflecting their more extensive borescope inspection work carried out on the Hardwoods Olympus C Engines in May 2007. We have included the ALBA Report in Appendix 4 as the ALBA observations and recommendations are similar to the conclusions arrived at in this Study. In addition, the ALBA photos clearly highlight the issues associated with each Engine.

6.2.2 Gas Generator/Power Turbines Auxiliary

Some auxiliary system components are obsolete and are no longer supported by the manufacturer or have been supplanted by more modern equipment. These include;

- Ignition exciters
- Vibration monitoring system.
- Speed governors/fuel valve assemblies.

Replacement auxiliary assemblies of current design are readily available however they do entail costs that will need to be considered. HYDRO should decide on its requirement for plant availability so that alternative strategies of installing new systems versus holding a stock of spare parts on site can be compared.

Woodward Governors

The Woodward speed governors are covered in sub-section 6.2.1 wherein it was stated that the on-engine auxiliaries were observed to be in satisfactory condition. Spares for the governors are readily available.

Gas Generator Bearings

The major line bearings were not accessible in the time allotted for inspection. The gas generator engine line bearings (8) are of the rolling element type. Inspection of the magnetic chip detectors indicated satisfactory bearings condition.

Gas Generator Lube Oil System

The engine's lube oil supply/scavenge system is self contained and driven by the engine assembly. It appears to be in satisfactory condition. The oil is cooled by means of a heat exchanger that uses incoming fuel oil as a coolant for the engine lube oil.

Compressed Air System

There are two starting air compressors mounted on the auxiliary module in an enclosed room within the Control Building and two storage tanks for start-air located outside the Control Building. The system provides sufficient air for three engine starts. The two air-cooled compressors are rated to deliver air at a discharge pressure of 500 psig. Each compressor contains an air inlet filter and silencers, and are driven by two 7-1/2 HP AC motors.

The two compressed air storage tanks (receivers) are sized to provide sufficient volume for at least three repeated starts of the gas generators. Relief valves are mounted on each tank to protect it from overpressure. Water traps are provided to automatically remove the condensed water from the bottom of each of the storage tanks. There is also a heating cable included in the drain circuits.

The control system provides conventional start/stop control with lead/lag compressor selection. Compressor instrumentation appears in good working order.

The compressed air system is of standard design and appears to be in reasonable condition for a further 15 years of service however the exact same components may not be available for the coming 15 years. A single spare compressor for both sites is probably adequate to provide for continuous plant availability.

Starter Motors

The starter motors have provided high reliability, but the model is no longer supported by Rolls Royce. It is suggested that a spare unit compatible with all four gas generators, should be carried by HYDRO. (The inventory of spare parts dated 2004, includes one starter motor assembly).

6.2.3 Inlet Air Systems A & B

The Stephenville inlet air system to the gas generators are in two plenum modules A and B (Photo: SVL-001). Each contains the gas generator inlet air filters, bypass doors, silencers between the inlet filters and plenum, hoist provisions for gas generator removal and installation. The primary air flow is introduced into the filter enclosure passing through louver vanes for water separation and then through fiberglass filter packs for fine particle separation. The primary airflow path then continues through the inlet silencer and into the inlet plenum. The inlet air filtration system at Stephenville is different to that installed at Hardwoods.

In the event of extreme conditions where a high degree of contamination exists, blow-in doors located in the rear wall of the inlet filter enclosure will open when the pressure drop across the filters and silencers exceeds three inches of water. Whenever the counterweighted blow-in doors open, an indicator light will be illuminated on the control panel in the control module to alert the operator that a filter inspection or media change is required. An access door is provided in the rear wall.

The inlet silencer duct is located between the inlet filter and plenum. Contained in the silencer duct are acoustically treated parallel baffles made of dense fiberglass sandwiched between perforated steel panels. The silencer is designed so that the sound power level in decibels is within specified limits. The system is designed to achieve noise levels at a distance of 1,000 feet less than 54 dBA or 95 dBA at a distance of 3 feet.

Entrance to the inlet plenum is accessible through the hinged bolted doors located at the forward end and through a removable 24” x 12” panel. At the rear of the plenum, a split septum door is located which is cut away to permit the gas generator inlet flare to protrude into the plenum area about 6½ inches.

A secondary air supply is provided through a duct mounted on top of the turbine module. The secondary air entrance is provided with a bird screen and the air passes through a fiberglass assembly consisting of 2’ x 2’ x 12” elements. The air then passes through silencer baffles to two electrically operated fans and is discharged into the front end of the turbine module to limit the temperature of the air to 125°F (52°C). The fans come on whenever the unit is started and remain on during operation and after shutdown until the temperature sensing probe at the rear of the turbine module senses a temperature below 115°F (46°C).

The inlet structures are constructed of structural steel plate and framing supported by a cast-in-place concrete foundation. The concrete foundation was found to be in adequate condition and there were no visible cracks noted. As well, no significant structural steel issues were noted during the inspection. The exterior of the air inlet structures was recoated approximately one (1) year ago. The exterior coating was found to be in good condition and no corrosion was noted.

There were several items noted during the inspection that require maintenance work. It was noted that the coating on the concrete slab located inside the inlet plenum was peeling. The paint peeling can then be sucked into the inlet of the gas turbine and potentially cause damage to the turbine. We recommend that the concrete slab be cleaned, prepared and coated with breathable masonry paint such as Loxon by Sherwin Williams (Photo: SVL-003).

Surface corrosion of the steel and flaking of the steel coating was noted inside the air inlet structures. The corrosion has caused the steel coating to flake as well as rust flaking. This loose material can then be sucked up by the gas turbine and potentially could cause damage. We recommend that the interior of the air inlet plenum and silencers be sand blasted and recoated (Photo: SVL-002).

The interior of inlet air plenums A and B show signs of corrosion damage. The basic structural integrity is good, and can be returned to satisfactory condition with basic cleaning and replacement of the surface coatings.

Significant corrosion was also noted in the trough under the access doors for both air inlet structures. This corrosion is likely a result of water accumulation in the trough over extended periods of time. We recommend that the following items be completed to repair this problem and help prevent it from reoccurring:

- Sand blast and coat all areas corroded under the access doors to the air inlet plenums (Photo: SVL-004).
- Weld new plates inside the troughs that will drain water to the centre of the trough.
- Drill a weep hole in the exterior of each air inlet structure to allow water to drain from the trough under the access doors.
- Replace the weather stripping on the access doors.
- Install a new drip cap over both access doors similar to the drip caps over the man doors on the gas generator/turbine modules and alternator modules (Photo: SVL-005).

The inlet bell-mouth assemblies are not fitted correctly to the engine, causing inlet air turbulence and loss of efficiency. In the case of air inlet system A, the rubber sealing strips around the exterior doors are deteriorated to the point of cracking and no longer making effective seals against unwanted air leaks (Photo: SVL-005). In the case of air inlet system B, the inlet bell-mouth assembly is out of alignment approximately .250” creating significant turbulence to the inlet air stream. As the units, during full power settings, ingest over 240 lbs/sec, the importance of correct bell-mouth fitment cannot be overemphasized. Misalignment will create turbulence in this air stream, accelerating compressor blade root wear, and costing up to 500kW of potential power output loss.

Both inlet air systems show signs of significant deterioration and corrosion damage. This deterioration is compromising the effectiveness of the inlet air filtration and contributing to abrasive wear to the engines' compressor components. HYDRO staff should be aware of the criticality of keeping the inlet air systems clean, and not allow small rocks and debris to enter into the systems during periodic maintenance.

There is evidence of silica sand, rust scale, small rocks in the inlet plenums, which eventually will be ingested by the turbine engine.

It was also noted that the steel grating on the platforms attached to the air inlet plenums was in poor condition having significant corrosion in some areas. We recommend that the grating on both platforms attached to the air inlet structures be replaced (Photo: SVL-006).

Access to the top of the air inlet structure is provided by a ladder. However, it was noted that there was no fall arrest system in place at the top of the air inlet structure. We recommend that new 42" high handrail with kick plates be installed around the perimeter of the top of each air inlet structure for fall protection.

It was noted that holes in the existing structure for attaching hoist beams have enlarged significantly. We recommend that new plates with holes of the proper size and location be welded to the existing structures to prevent pullout of bolts during lifting procedures for safety purposes (Photo: SVL-007).

6.2.4 Exhaust Stacks A & B

The exhaust stacks for both power turbines (Photo: SVL-008) are constructed of a heavy gauge steel plate with stiffeners on the exterior of the structure, with heavy gauge steel plate liners on the interior. Based on the drawings viewed on site, the interior liners of the exhaust stacks are welded to the exterior structure with horizontal bent plates around the perimeter of the structure and installed at regular vertical intervals. It is our understanding that the void between the interior liner and exterior structure is filled with insulation. The snow doors on the exhaust stacks were modified from electric actuation to pneumatic operation in 1989.

The exteriors of the exhaust stacks were recoated approximately one (1) year ago. The exterior coating was found to be in good condition and no corrosion was noted. The concrete foundation under the exhaust stacks was visually inspected and was found to be in acceptable condition with no visible cracking or significant deterioration. It was noted that the exterior gusset plates on the four corners of the exhaust stack for Power Turbine B were bent. These gussets plates were likely damaged during transportation or erection of the exhaust stacks.

This does not present any structural concerns at this time as the steel structure in the vicinity of these gusset plates is in good condition and does not show any signs of deformation.

The existing handrails on the platforms attached to the exhaust stacks are only 36" in height, do not have kick plates and therefore do not meet fall protection regulations. We recommend that kick plates be added along with additional top rails to the existing handrails to extend the height of the railings to a full 42 inches. It was also noted that the floor grating on these platforms consisted of expanded metal mesh which distorted significantly under foot. We recommend that this be replaced with standard bar grating which is much stronger and durable (Photo: SVL-008).

The existing access hatch for the exhaust stack of Power Turbine B was also reviewed. These access hatches are quite small, making access for HYDRO site personnel difficult. The current hatch arrangement also makes removal and reinstallation difficult and time consuming. To make the hatches water tight caulking must be applied to all joints. Caulking should only be relied upon as a secondary seal and not the primary method of making a joint weather tight. Should the hatch have to be removed during the winter months, it would be very difficult to make the hatch weather tight as the caulking will not setup at low temperatures. We recommend that the existing hatches be replaced with operable man doors with proper flashings and weather stripping (Photos: SVL-009 & 010 & 011).

HYDRO personnel also indicated that they cannot easily access the pneumatic cylinders which operate the snow doors on top of the exhaust stacks. We recommend that the existing platforms be modified to support new ladders that will allow site personnel to visually inspect the condition of the pneumatic cylinders and hoses (Photo: SVL-008).

In both exhaust stacks, cracking is evident at the joint of three (3) flat planes within the vertical stacks in two (2) locations. This cracking was noted in the bottom south-west and north-west corners of the exhaust stack liner for Power Turbine B. These were viewed from the access door of the exhaust stack. Cracking was also noted in the bottom south-east and north-east corners of the exhaust stack liner for Power Turbine A. These cracks were viewed form inside the clutch module for Power Turbine A. It is believed that this cracking exists in all four bottom corners of the liner in each exhaust stack. The cracks do not appear to be compromising the structural integrity of the exhaust stacks as a whole, rather may be a result of thermal cycling over time, relieving stress at these points.

Based on the drawings viewed on site for the exhaust stacks, it appears that the exhaust stack liner is rigidly fastened to the exterior structure. With this arrangement, the interior liner will heat up and expand due to the hot exhaust gases from the gas turbines, while the exterior structure is insulated and will therefore remain relatively stable in temperature. Since the liner is constricted by the outer exhaust stack structure, high stresses likely build up in the liner. The stresses would be highest at the bottom of the liner where it gets the hottest and at locations of discontinuities, such as joints and corners. Given the location and orientation of the cracks noted above, it is believed that these cracks are a result of the thermal expansion and contraction of the exhaust liner which is constrained by the exterior structure.

In the south-east corner of the exhaust stack for Power Turbine A, it appears that a former crack in the liner was repaired by welding the crack. However, a similar crack in the liner has appeared adjacent to the repaired crack. Simple weld repairs may repair the cracking, however over time, it is highly likely that the cracks will reappear, and if the areas in question are ruggedized (ie. weld repairs with reinforcing materials), it is also likely that the stress cracking may appear in the next weakest location due to the nature of thermal expansion/contraction in flat planes. The remainder of the exhaust systems appears to be in satisfactory condition.

6.2.5 Curtiss Wright Power Turbines A & B

There are two Curtiss Wright Power Turbines A and B. Each Curtiss Wright power turbine is a two-stage axial flow unit with the rotor assembly and main shaft supported as a cantilever by two white metal bearings housed in a pedestal. The power turbine unit is connected to the gas generator by a gas duct incorporating a bellows joint. The gas generators receives ambient air from the air inlet plenums and delivers high temperature and pressure gas to the power turbines which converts the thermal energy into rotating mechanical power. The power turbines output shaft is coupled to the alternator through SSS clutches.

The two-stage axial flow rotor consists of two rows of cast Stellite 31 blades. The blades are attached to a forged 422 stainless steel disc; the blades are secured to the disc by fir tree root fixings. The rotor assembly consists of a front labyrinth ring, first stage blade and disc assembly, spool spacer, interstage labyrinth, second stage blade and disc assembly and the main shaft. The components are fixed to the main shaft by tie bolts. A diagram (Figure 2-58) illustrating the power turbine assembly is included in Appendix 4.

The oil supply to the power turbine is supplied from the alternator module and provides lubrication to the front and rear main radial bearings and the thrust bearing.

The stator casing was originally made of austenitic nodular cast iron alloy, split on the horizontal centre-line to facilitate access to the stator vanes and the rotor. The casings however were prone to severe cracking resulting in a de-rating of the gas turbine for a number of years. In the 1980's new casings were designed, manufactured and installed on both gas turbines. The new casings used an incanol alloy that is less prone to cracking. There have been opportunities to inspect the blading of end B at Stephenville when the gas generator was removed for extensive overhaul in 2000. The Curtiss Wright Power turbines A&B have provided excellent service since the major modifications to the casings. There have been no records of significant problems noted or significant work carried out on the power turbines over the past 12 years.

The elements that could impact on the reliability and availability of the Power Turbines are the blades, discs, bearings, and vibration characteristics. These are somewhat inter-related with uneven deterioration of the blades leading to degradation of bearings and vibration characteristics.

From our review of operations of the Stephenville Facility particularly the minimal running time on the power turbines and our visual examination during the site visit, there is no expectation that the Power Turbines performance will change significantly during the next fifteen years. We recommend however that upon removal of the engine assemblies as noted in sub-section 6.2.1, the Curtiss Wright power turbine assemblies should be inspected in detail to verify the mechanical integrity of the units. In order of priority the following points are recommended to be inspected / refurbished;

- Main line bearings to be removed and inspected.
- Turbine blades to be removed and metallurgical sampling done to verify alloy composition, as well as check wear to the blade roots.
- Turbine disks to be removed and metallurgical sampling done to verify alloy composition and creep growth.

More modern and effective anti-corrosion/thermal protection coatings are available, and are recommended to be applied to the power turbine blades & nozzles to give superior protection/reliability for future operation.

6.2.6 SSS Power Turbine Clutches A & B

The SSS Clutch is designed for use between a turbine and an alternator to primarily engage and disengage the gas turbine from the alternator when the alternator operates as a synchronous condenser. When operating for generation purposes the clutch will remain engaged with the alternator. In the case of synchronous condenser operation, the clutch can automatically connect the turbine to the alternator at any speed, with engagement occurring immediately when the turbine speed exceeds that of the alternator. The design accommodates changes in the alignment of the gas turbine and alternator shafts to allow for thermal expansion effects. It acts as a double toothed flexible coupling with tooth surfaces that are designed for low stress and are hardened by nitriding. The clutch is lubricated by oil catchers on the input and output shafts. A dashpot system provides oil to maintain clutch engagement in the event of a reduction of turbine power to the idling mode.

The Power Turbine Clutches A and B were not accessible in the time allotted for inspection during the site visit. A review of available operational history indicates that all problems associated with the clutch assembly have originated with the various sub-systems such as - position indication, brake function and shifting mechanism. All other history indicates satisfactory operation of the clutch assembly itself.

There has been no reported significant work carried out on the Clutches over the past 12 years. The clutch system itself has provided good service and should continue to do so for the next 15 years. There have been a number of problems with the auxiliaries such as the hydraulic system and the position monitoring. These have resulted in difficulties to clutch operations when synchronizing the power turbine with the spinning alternator. It is advised that the components comprising the auxiliaries to the clutches be reviewed for potential replacement with currently available and proven reliability components.

It is recommended that when the gas generator engines have been removed for refurbishment, the drive clutches be completely disassembled and inspected. No major structural problems are anticipated however the brake, position indication and actuation systems should be refurbished and tested to achieve continued reliable operation. It may be prudent to place spare internal components into inventory, as the availability of such parts into the future are unknown and may be cause for concern.

6.2.7 Main Power Train Bearings

The major power train bearings were not accessible in the time allotted for inspections. The power turbine and alternator bearings are of the journal, pressure lubricated type. Review of oil sampling results with operational staff indicated no anticipated problems with these bearing assemblies.

6.2.8 Main Lube Oil System

The main lube system is a closed loop that incorporates a tank that is partioned internally to allow for entrained gas (air) in the return to evacuate. The tank is large enough to store and maintain oil temperature. Oil is delivered under pressure to the power turbine, clutches and alternator and is returned to the tank by gravity and negative pressure generated by a vacuum fan on the tank.

The oil is moved and pressurized by the lube oil pumps. Constant pressure is maintained in the discharge header by means of a regulating valve which establishes a header discharge pressure of 30 psi (2.04 bars) by sensing discharge pressure after the cooler and filters. The pumps are protected by a relief valve which is set at 100 psi (6.8 bars) and will bypass lube oil in the event of system blockage.

The power turbines, clutches and alternator low pressure lube oil system proper all appear to be in satisfactory condition. The high pressure rotor jacking oil system also appears to be in satisfactory condition.

From the lube oil pumps, the oil flows to an oil/water-glycol cooler. The cooler is a shell and tube type heat exchanger with internal baffles that allows a heat exchange from the oil to the coolant glycol, which is actually a glycol - water solution.

The glycol coolant from the main lube oil cooler is circulated by pumping through a 3-way valve that controls the quantity re-circulated back to the oil-cooler or to the glycol/air heat exchanger (glycol-cooler). As the main lube oil delivered from the oil tank gets warmer, the 3-way valve will operate under the control of its capillary, and will slowly restrict the re-circulating glycol coolant such that the coolant has to pass through the external glycol/air heat exchanger and then back via the 3-way valve where it is mixed with the warmer coolant still circulating, and then to the main lube oil cooler. In this manner, the 3-way valve controls the flows in the coolant sections of the heat exchangers to maintain a steady delivery temperature of oil to the bearings.

The main lube oil system electrical, mechanical and instrumentation equipment is generally in good condition but if certain components such as pumps or fans fail completely, it may be difficult to find the identical item for replacement. The necessary precaution would be to acquire spares for HYDRO to stock. This is particularly relevant to the single glycol circulating pump. It is noisy and should be subjected to a major overhaul. The power plant will be unavailable for operation in the absence of this pump. HYDRO should decide on its requirement for plant availability so that the alternative strategies of installing a back-up pump versus holding a spare pump on site can be compared.

6.2.9 Glycol Cooler for Main Lube Oil Cooling System

The external glycol heat exchanger (Photo: SVL-012) is of the finned tube air blast type with its electrically-driven cooling fans and the coolant circulating pump controlled by a sequencer. The main lube oil external glycol cooler assembly is in poor physical condition.

The existing glycol lube oil heat exchanger is constructed of heavy gauge sheet steel frame with support posts and braces fabricated from structural steel angles. At the time of inspection, this equipment was undergoing repairs to the structure to repair damage caused by corrosion. The majority of the joints on this structure were stitch welded together. This detail allows water to enter the joint and promotes corrosion at these locations. The expansion of the steel (rust) as it corrodes causes the steel plate to deform between the welds. In a couple of locations this expansive force has caused some of the welds to crack. However, the main structural members are in acceptable condition.

The repairs being completed entailed; new 3” x 3” hollow structural posts under each end of the fan and motor support channels, re-welding of broken welds and installation of gusset plates. These repairs are adequate to keep the unit operating for the next year. However, the unit should be refurbished within the next couple of years to keep it operational for the next 15 years.

To refurbish this unit for the next 15 years, we recommend replacing the bottom section of the heat exchanger, replacement of the canopy cladding and recoating of the entire structure. The replacement bottom section should be generally similar to the existing bottom of the unit. However, it should be designed to provide for adequate drainage of water and all joints should be seal welded. The existing bottom can be cut off, motor and fans remounted on the replacement bottom and this new bottom can then be welded into place. The canopy on this heat exchanger is covered with corrugated light gauge sheet steel cladding. Surface corrosion on the cladding was noted in several areas. Therefore, at the time of refurbishment we recommend that this cladding be replaced as well (Photos: SVL-013 & 014).

6.2.10 Gas Generator/Power Turbine Enclosures A & B

The gas generator/turbine modules are constructed of structural steel framing with a steel plate exterior cladding. The exterior of the gas turbine modules were recoated approximately one (1) year ago. The exterior coating was found to be in good condition and no corrosion was noted. The concrete foundation under the gas generator/turbine modules was visually inspected and was found to be in acceptable condition with no visible cracking or significant deterioration.

A visual inspection of the gas generator/turbine module supports and welds was carried out and no issues were noted. A visual inspection of the exposed steel structure inside the gas turbines modules was also completed. It was noted that there were some areas in which surface corrosion was present on structural members. These areas were generally small and the corrosion mild and therefore are not a significant concern at this time. However, if this facility is to remain in operation for the next 15 years, the next time the gas turbine equipment is removed for maintenance, we recommend that the interior of the gas generator/turbine modules be cleaned, areas with corrosion sandblasted and the interior of the modules be recoated (Photo: SVL-015).

It was noted that the existing handrails on top of the gas generator/turbine modules do not meet fall protection regulations. The handrails were only 36 inches high and did not have kick plates installed. For fall protection purposes, we recommend that the railings be replaced or modified as soon as possible. New railings should be a minimum of 42 inches high with a handrail, mid-rail and kick plate. Kick plates could also be added to the existing hand rails along with an additional top rail to make the handrail 42 inches high (Photo: SVL-016).

The existing man doors in the gas turbine modules do not have any windows. We recommend that windows be added to the doors for safety purposes. This will allow Hydro site personnel to view the interior of the module before opening the door. This would be particularly helpful should there be a fire inside the gas generator/turbine modules. The handrails on the stair landings for these modules also do not meet code as they are not 42 inches in height and do not have kick plates. We recommend that an additional top rail be added to extend the height of the handrail to a full 42 inches and kick plates be added to the bottom of the handrails (Photo: SVL-017).

It was noted that holes in the existing structure for attaching hoist beams and other equipment have been enlarged significantly. We recommend that new plates with holes of the proper size and location be welded to the existing structures to prevent pullout of bolts during lifting procedures for safety purposes (Photo: SVL-018).

6.2.11 Fire Detection and Protection

The fire suppression system consists of Inergen systems located (i) in the turbine enclosure (Module A and B) and the alternator enclosure (Clutch A and B compartments) and (ii) in the fuel forwarding building. There are heat and smoke detectors located at each location.

There is not a fire suppression system located in the control building. In response to a HYDRO request, Stantec provided HYDRO with a preliminary cost estimate for installing an Inergen system in the control building. For protection and insurance reasons, we recommend that an Inergen system be installed in the control building.

The Inergen fire suppression systems are in excellent condition and available for service for an additional 15 years.

6.2.12 Gas Generator/Power Turbine Spares

An observation made during the visit to Stephenville, and during inspection of the available outage/maintenance reports provided, is that if additional spare parts inventories were held on-site, the overall reliability of the package could be enhanced. Recommended Gas Generator Engine spares include:

> Fuel injection nozzles: A majority of unscheduled shut downs are caused by high exhaust gas temperature deviation. A spare set of flow balanced fuel injection nozzles would allow mechanical staff to replace defective nozzles with serviceable units, to bring total temperature deviation to within acceptable limits.
>
> Starter assembly: These units are no longer available from the original manufacturer, and are understandably critical to the operation of the package. A spare starter assembly would enhance current and future reliability.

There are companies that hold spare parts and complete gas generators in anticipation of future requirements. We recommend a strategy whereby HYDRO can set up a system of quick replacement if needed. It is unlikely that both gas generators will become unserviceable simultaneously allowing the alternator to be operated as a synchronous condenser or at 50% MW output on one or other gas generator.

6.3 ALTERNATOR/EXCITATION SYSTEM

6.3.1 Alternator Description

The Stephenville Alternator and Excitation System were manufactured by the Brush Electrical Machines Ltd. of England in 1975. The Alternator was designed to ANSI Specification C50-13. The 13,800 volt, 3 phase 3600 rpm Alternator is an air cooled machine rated at 63,530 KVA at a 0.85 power factor. The Alternator utilizes a rotating brushless type exciter mounted on a stub to the main rotating shaft. The Alternator cooling consists of an external glycol cooler and a 50/50 glycol/water cooling medium to remove heat from the alternator heat exchangers (air to coolant) located at both ends of the alternator. Refer to sub-section 6.3.8 for further details on the Alternator air glycol cooling system.

The Alternator/Exciter is enclosed by a weatherproof, walk-in sound insulated enclosure. The stator is fastened to the enclosure bedplate. The Alternator is enclosed with two end canopies (bulkheads) and a top section canopy. Each canopy is accessible via doors. The alternator enclosure is protected by an Inergen fire suppression system. Refer to sub-section 6.3.7 for further details on the Alternator enclosure.

The alternator's inner stator frame is fabricated from structural steel, welded together to form a rigid structure. The stator core consists of low loss, silicone steel segmental stampings insulated by a layer of varnish on both sides of each lamination. The core is divided into short sections by radial ventilating ducts. The core is bolted to the stator frame. The stator copper winding is of the two layer diamond type with the coils held in open slots by epoxy paper laminate wedges. The two coil layers are separated by epoxy paper laminate wedges. The insulation is Class B synthetic resin bonded mica glass tape. The stator winding laminations are transposed in a regular pattern to minimize circulating currents and losses. The coils are protected against corona formation by coating in the slot length with conducting (graphite) paint and with corona relief paint at each end of the core. The end winding coils are braced with glass cord and densified epoxy paper laminate blocks and supported from the core ends by insulated brackets.

The stator line and neutral terminals are brought out to a cubicle containing the line and neutral bushings. The line bushings are connected to a metal enclosed bus duct system. The Alternator neutral is grounded via a grounding transformer and resistor (refer to section 6.5 for further details on the bus duct, the alternator circuit breaker and neutral grounding).

The rotor consists of a solid carbon steel forging carried in two bearings with a shrunk on half coupling. The field windings are located in slots milled into the rotor forging. The windings are held in place by steel and bronze wedges. Intertooth slots are milled to provide a longitudinal air passage for the cooling air. The windings consist of multi-turn copper coils insulated throughout with Class F mica. The end windings are supported by non-magnetic end caps shrunk on to a spigot on the rotor body and braced with resin bonded asbestos fabric packing blocks and boxed in with a steel end bracket. Early end caps used 18%Mn / 4%Cr non-magnetic material whereas more current designs use 18%Mn / 18%Cr. The former is susceptible to stress-corrosion cracking. It is recommended that the end caps be closely examined during the refurbishment project.

The alternator and exciter bearings (3) are carried in a fabricated steel pedestal. The housing is split horizontally on the shaft centerline. The bearing is white metal lined and spherically seated. Bearings are lubricated by pressurized oil at 20/30 psig (refer to sub-sections 6.2.7 and 6.2.8 for further details). The oil drain systems operate below atmospheric resulting in air being drawn in through the labyrinth seals providing the necessary ventilation. A high pressure jacking oil system is provided for start-up and shut down purposes.

The stator winding temperature is measured by embedded resistance temperature detectors (RTDs) distributed throughout the windings in the slots. There are 4 RTDs per phase. Alternator air temperatures are measured by thermocouples fitted in the air outlets and inlets from the stator as well as the exciter air outlet. The temperature of the drain oil in each pedestal bearing is measured by an immersed thermocouple. A vibration detector is mounted on the pedestal of each rotor bearing and on the exciter bearing pedestal.

6.3.2 Excitation System Description

The main exciter is of the rotating brushless type mounted on a stub shaft which forms an extension of the main drive shaft at one end of the machine and is supported by a third bearing. The brushless exciter was designed to ANSI Specification C50-13. The exciter has stationary field coils and a rotating armature. The exciter field windings are on the stator and its armature is on the rotor. The AC output from the exciter armature is fed through a set of diodes that are also mounted on the rotor to produce a DC voltage. This is fed directly to the field windings of the main alternator which are also located on the rotor. The excitation control system consists of a “Normal” and “Standby” automatic voltage regulator (AVR) backed up by a “Manual” control mode. The AVR controls the strength of the magnetic field in the exciter by varying the amount of current through the stationary exciter field windings. The Stephenville Gas Turbine utilizes the original brushless exciter and the AVR control system provided in 1975.

6.3.3 Alternator/Excitation General Assessment

As noted previously, the configuration of the Stephenville Gas Turbine includes two engines, two power turbines and only one Alternator. This makes the Alternator a critical component in the availability and reliability of the Gas Turbine. An Alternator problem therefore can result in major outages.

While HYDRO personnel have indicated the Alternator and Exciter have generally provided good reliable service at Stephenville, the actual condition of the stator, rotor, exciter and auxiliary components is somewhat unknown. HYDRO was not able to provide documentation, during the Study, outlining a history of Alternator and Exciter condition testing on this equipment ie data from electrical tests and inspections carried out on the equipment over the years. In order to properly assess the present condition and life expectancy of the Alternator and Exciter, it is very important that data from such tests and inspections, if carried out on the equipment over its years of operation, be current and available for review. Unfortunately, this information was not available. A comparison of the test results taken over a period of time will usually indicate trending patterns good or bad. Since this information was not available, such an assessment was not able to be carried out in the Study.

With the type of operation the Alternator has been subjected to over the years – frequent stop/starts and synchronous condenser mode operation (refer to sub-section 2.2) - expectations are that the stator core, stator and rotor windings/insulation, rotor retaining rings and bearings will all show signs of ageing and would be a risk area of concern for available and reliable operation over the next 15 years. HYDRO did not provide any reports on major refurbishment work carried out on the Alternator in the past. This is not to say that there was no refurbishment work carried out. Typical alternator stator and rotor problems that can develop over time from such operation can include:

<u>Potential Alternator Stator Problems</u>

- Stator winding insulation integrity and cracking
- Stator windings -- bar movement, sparking, bulging or puffy coils
- Stator end windings – bar movement, loose/broken bracing and ties, corona (arcing) activity
- Stator wedges – looseness, sparking damage
- Stator core insulation – hot spots. Shorting or low resistances in the inter-laminar insulation may result in abnormal currents, localized heating and iron damage.
- Cracked connections
- Contamination

<u>Potential Alternator Rotor Problems</u>

- Shorted turns and field grounds – occurs when the insulation in the field is damaged. There are a number of factors that can lead to field insulation breakdown/degradation – (i) length of time the alternator has been in service (ii) mode of operation – frequent start-stops (thermal cycling) or base load operation and (iii) contamination introduced into the machine

- Rotor wedges -- looseness, sparking damage

- Thermal sensitivity – is a term used to describe an excessive vibration of the rotor induced by the heating effect of the field current. As field current flows, the copper winding heats up and having a greater coefficient of thermal expansion, expands more than the steel forging. The disparity in expansion transmits forces to the forging through the rotor slots, wedges and retaining rings. The heat generated in this manner is normally drawn away by the cooling medium (air). Problems can occur when the winding forces act unevenly or when a temperature differential exists across the rotor due to blocked ventilation. These events will cause the rotor to bow somewhat resulting in an imbalance and subsequent vibration.

- Negative sequence events -- operating incidents (closing the alternator breaker when at standstill; single phase operation; transients, etc) that induce heating, arcing within the alternator
- Contamination – problems that arise from contamination buildup on the rotor include low megger readings, overheating and creepage failures
- Forging/retaining ring damage – rotor forgings over time can develop cracking or burning caused by extraordinary events such as negative sequence currents flowing in the forging. Retaining rings are the highest stressed components of the alternator. Alternators operating in cycling modes that require frequent start-stops are susceptible to rotor tooth top cracking. It is generally recommended that rotors that have been in service in excess of 25 years with approximately 5000 start-stops should be inspected for damage.

In the absence of electrical testing and inspection records as well as any major refurbishment work reports on the Alternator over its 30 years of service, it is difficult to determine if any of the potential problems listed above currently exist or might occur in the next 15 year period. In order to determine the present condition of the Alternator and Exciter the following recommendations are proposed:

- A series of electrical tests in line with sub-section 6.3.5 be carried out on the Alternator at the earliest opportunity to provide a snapshot on the current condition of the Alternator.
- In addition to the electrical tests noted above and in order to determine what specific refurbishment work might be necessary on the Alternator in particular, it is recommended that the Alternator itself or as a minimum the rotor be physically removed from its enclosure and the visual inspections and electrical tests noted above be carried out. This detailed examination will clearly determine the condition of the Alternator and its components and the specific refurbishment work (if any) that must be carried out to ensure its ability to operate reliably for a further 15 years.

6.3.4 Alternator/Excitation Operational and Maintenance Issues

The preceding sub-section listed potential typical and potential Alternator stator and rotor problems that can develop over time. This sub-section will outline problems noted by HYDRO personnel and any refurbishment work carried out on the Alternator in the past

There were reports of the operation of a negative sequence relay on start-up on several occasions. This was attributed to possible faulty settings of the relay. This may indeed be the reason; however, it is likely the relay detected a negative sequence event. Negative sequence currents can lead to rotor forging and retaining ring damage.

There are reported incidents of vibration alarms occurring on the exciter end of the Alternator on start-up. The reason for or cause of the vibration alarm has not been identified to date. This alarm could be caused by a number of factors – (i) faulty vibration detector (ii) shorted turns in a field coil (iii) rotor balance issue (iv) shaft alignment issue or (v) bearing issue.

As noted previously, there were no reports provided by HYDRO on any major refurbishment work that may have been carried out on the Stephenville Alternator over the past 30 years. This does not necessarily mean that no major refurbishment work was done. It could also be due to the fact any such reports could not be found.

Hydro does have plans to replace the existing original excitation AVR control system at Stephenville with an AVR similar to what was installed at Hardwoods in 2006.

6.3.5 Alternator/Excitation Testing Program

In order to assess the condition and life expectancy of the Alternator and its Excitation System, it is important that electrical tests and inspections be carried out on a regular interval basis (annually; semi-annually; etc) over the years and the data recorded. A comparison of the test results taken over a period of time will usually indicate trending patterns good or bad.

The following types of electrical tests are often carried out on an Alternator and Excitation System as part of ongoing inspection and maintenance programs:

<u>Stator Electrical Tests</u>

- EL-CID tests --- detects problems in the stator core especially interlaminar insulation defects (hot spots)
- Partial Discharge Test --- detects stator winding insulation deterioration
- Polarization Index Test --- tests the insulation resistance to ground
- Hi-Pot Tests --- Insulation test
- Megger Tests at 1000 or 5000 V DC
- Thermocouple tests/calibrations
- Inspection and tests of Alternator bushings

<u>Rotor Electrical Tests</u>

- Megger Tests at 500 V DC -- detects rotor winding insulation deterioration/ contamination
- Rotor winding resistance measurements

Bearings Electrical Tests

- Megger tests to indicate general cleanliness of bearing pedestal and insulation resistance
- Thermocouple tests/calibrations

Excitation System Electrical and Operational Tests

- Exciter rotor and stator winding resistance measurements
- Polarization Index measurements and Megger tests to determine condition of the exciter rotor and stator winding insulation
- Thermocouple tests/calibrations
- Diode checks - measurement of diode forward and reverse bias resistance and voltage drop; resistance of fuses; etc
- Operational checks on the AVR

The following Alternator visual inspections are often carried out as part of ongoing inspection and maintenance programs. These inspections, carried out during major outages with the Alternator removed from the Unit, can assess the condition of the stator, rotor and bearings. Items typically inspected during major outages are as follows:

Stator Visual Inspection

- Loose or damaged wedges;
- Loose or cracked or failed connectors;
- Dusting, greasing and other signs of movement of windings;
- Indication of arcing (hot spots); damaged laminations;
- Loose Core bolts;
- Signs of contamination / excessive dirt

Rotor Visual Inspection

- Signs of physical damage;
- Loose or cracked or failed connectors;
- Slot wedge migration and possible contact with retaining ring;
- Signs of overheating;
- Loose rotor wedges;
- Dye penetrant examinations and magnetic particle tests on forgings, retaining rings and fan components to detect fatigue cracks; ultrasonic examination of interior surfaces of the forging and retaining rings

Bearings Visual Inspection

- Assess general condition of the bearings
- Do the bearings require re-babbiting or machining?

HYDRO provided copies of its Gas Turbine daily, weekly, semi-annual, annual and 5 year inspection check lists as well as the 6 year P&C inspection check list. Most of these inspection check lists were dated 2003. There is essentially no reference to alternator and exciter tests or inspections on these lists. Copies of these lists are included in Appendix 5. In addition, there are Alternator and Exciter tests and inspections listed in the O&M Manuals for each site. It is not obvious that any of these recommended tests and inspections are being carried out by HYDRO.

On a go-forward basis, it is recommended that a regular formal inspection and test program be established for the Alternator and its Excitation System and that some or all of the above listed tests and inspections are part of that program. The electrical tests should be conducted on an annual basis with major visual inspections on a 5 year basis. The test data and inspection information should be recorded and stored at a central location for easy access in the future. In addition, a specific group at HYDRO should be charged with the responsibility for conducting such tests and inspections.

6.3.6 Alternator/Excitation Recommendations Summary

- It is recommended that a series of electrical tests be carried out on the Alternator at the earliest opportunity to provide a snapshot on the current condition of the Alternator.
- In addition to the electrical tests noted above, it is recommended that the Alternator itself or as a minimum the rotor be physically removed from its enclosure and the visual inspections and electrical tests noted above be carried out. This detailed examination will clearly determine the condition of the Alternator and its components and the specific refurbishment work (if any) that must be carried out to ensure its ability to operate reliably for a further 15 years.
- The Curtiss-Wright Turbine-Alternator Manual (Book 3) recommends a minimum list of spare parts that should be carried for the Alternator and its Excitation System. It is recommended that the suggested list of spares be stocked at one central location for both the Hardwoods and Stephenville sites.
- On a go-forward basis, it is recommended that a regular (annually; semi-annually; etc) formal inspection and test program be established for the Alternator and its Excitation System and that some or all of the tests and inspections listed in sub-section 6.3.5 be part of that program.

6.3.7 Alternator/Excitation Enclosure

The alternator module is constructed of structural steel framing with a steel plate exterior cladding. It is our understanding that the exterior of the alternator module was recoated approximately one (1) year ago. The exterior coating was found to be in good condition and no corrosion was noted. The concrete foundation under the generator module was visually inspected and was found to be in acceptable condition with no visible cracking or significant deterioration.

The interior structure of the alternator module was also reviewed. This module contains a great deal of equipment and access to structural members was quite limited resulting in the inspection of this module being also limited. No structural issues were noted.

The roof of the alternator module requires access from time to time for repair and maintenance activities; however, the roof of the existing generator module is over 10'-0" high and currently does not have any handrails. Therefore, this area does not meet fall protection and safety regulations. There are several existing eye-bolts attached to the roof of the generator module that may be adequate as fall arrest anchors; however, they are not close enough to immediately tie to once you have climbed to the roof level and are spaced far enough apart that HYDRO staff may have to unhook and hook to move to different areas of the alternator roof. It is important to note that no structural analysis has been carried out by Stantec to determine the capacity of these anchors for fall arrest purposes. We recommend that proper handrails be installed on the roof along the north and south sides of the alternator module for fall protection purposes (Photo: SVL-019).

The existing man doors in the alternator module do not have any windows. We recommend that windows be added to the doors for safety purposes. This will allow HYDRO site personnel to view the interior of the module before opening the door. This would be particularly helpful should there be a fire inside the alternator module. The handrails on the stair landings for this module also do not meet code as they are not 42 inches in height and do not have kick plates. We recommend that an additional top rail be added to extend the height of the handrail to a full 42 inches and kick plates be added to the bottom of the handrails.

6.3.8 Alternator Air Cooling System

The alternator cooling system uses a 50/50 glycol-water mixture to absorb heat from the air circulating inside the alternator casing and to discharge the heat to ambient air by means of an external heat exchanger complete with fan cooling.

Inside the alternator, air is passed through the air-gap behind the stator end windings and under the rotor winding. The space behind the stator core is divided into inlet and outlet compartments and air passes via radial ducts in the core to and from these compartments to the air-gap. Air from under the rotor windings flows through vents in the rotor surface in line with the outlet compartments of the stator core.

Under normal conditions, air is passed through a glycol/water finned tube heat exchanger (Photo: SVL-020) and circulated back to the machine. The glycol/water is pumped to an external heat exchanger where fans blow ambient air over a nest of finned tubes to cool the glycol. There are two glycol/water pumps for this system and two fans for the external heat exchanger.

At the time of our visit, the glycol cooler had been taken out of service. The alternator was being operated with the access doors to the canopy above the alternator wide open to allow circulation of unfiltered ambient air in the alternator. Open doors, in addition to allowing contaminants to enter the generator enclosure, may compromise the Inergen fire suppression system. It was reported that an alternator high temperature alarm had come up during recent operations and while the cause of the alarm has not been identified, there is concern that the glycol/air heat exchanger may be unable to dissipate sufficient thermal energy. High temperatures in the alternator have been the source of shutdowns in the past. HYDRO will commence investigations to determine the cause of the high temperature alarm.

The cooling system should be capable of dissipating about 5GJ/hour during the highest ambient temperatures, say 30^{o}C. Calculations by Neill and Gunter, using test data provided by HYDRO, suggest that the external cooler is operating at about 67% of its design capacity. If this is indeed the case, there is a limit on the maximum output (MW) that the unit can provide on a continuous basis. The limit is a function of the ambient temperature.

The finned tubing of the external heat exchanger was observed to have a grey dust coating on the fins. This will impair heat exchange, and it is proposed that a test be undertaken to measure temperatures of coolant in/out, and air in/out of the external heat exchanger. Also, if possible, a means of measuring the flow of coolant should be devised. These data can be used to calculate the capacity of the exchanger, and to establish the improvements achieved by cleaning the external fins.

Similar data should be collected for the heat exchanger inside the alternator casing to verify that it is still operating at or near design conditions.

The external glycol cooling heat exchanger is constructed of structural steel columns, braces and framing. The exterior of the heat exchanger and the canopy of the heat exchanger are clad with heavy gauge steel plate.

Surface corrosion on the main structural steel framing members was noted in several areas. However, this corrosion was generally light and the steel framing members were found to be in acceptable condition.

The heavy gauge exterior cladding on the heat exchanger and the canopy was stitch welded to the structural steel framing. Over time water has entered the joints between the cladding and structural framing which were not welded and this has resulted in corrosion of the steel at these locations. The expansive forces created by the steel turning to rust has caused the heavy gauge steel cladding to deform along the panel perimeter between the stitch welds.

Given the level of deterioration, we recommend that the heat exchanger support system be recoated within the next two (2) years if it is to remain in service for the next 15 (15) years. At that time, the existing cladding should be removed and replaced with new heavy gauge sheet steel. All joints between the cladding and structural framing should be seal welded to minimize corrosion at these joints in the future (Photos: SVL-021 & 022 & 023).

The cooling equipment itself should be adequate for a further 15 years, subject to the refurbishment to the structural components noted and the resolution of the alternator high temperature alarm (if a glycol cooler problem) being rectified by cleaning the tubes and external fins. This also assumes that a maintenance schedule is put into operation that provides for cleaning the tubes regularly.

Instrumentation on the alternator cooling system appears in good working order. There have been no significant instrumentation problems in the last year and a half. At the time of the site visit, the coolant had been drained and the low level switch did not operate. There may have been some coolant left in the tank. The operator was to verify at a later time.

6.4 FUEL OIL SYSTEM

6.4.1 Fuel Unloading and Storage

The Gas Generator Engine fuel is No. 2 diesel oil which is delivered to the Site by truck. The trucks are unloaded via pumps at the Fuel Forwarding Building. Fuel storage comprises three interconnected storage tanks each with 126,000 nominal gallons capacity (477,000 litres) (Photo: SVL-024). At 50 MW, the plant will use about 16,000 L/hour, so one tank lasts approximately one day. All three storage tanks contained oil at the time of inspection. Therefore, only visual inspection of the exterior of the tanks was carried out.

The tanks were built to API Standard 650, and should be operated subject to API Standard 653 – Tank Inspection, Repair, Alteration and Reconstruction. This standard calls for periodic inspections and records of construction, inspections, and repairs. The frequency of inspections can be linked to a rate of corrosion or in the absence of measurements the frequency of inspection must be less than every ten years.

The tanks have been in service since 1977. The tanks were inspected in 1999 by *fga*-CANSPEC (Reports provided by HYDRO) in accordance with API 653 -1995. The tank shell was found to have no internal and external corrosion and no areas of pitting or weld attack. Inspections of the tank floors consisted of magnetic flux leakage scanning and a systematic ultrasonic thickness survey. The remaining useful life of the tank floors as estimated by fga-CANSPEC are as follows: Tank 1 (16 years); Tank 2 (8 years) and Tank 3 (15 years). The roof and roof rafters on all tanks were found to be in good condition. All tanks were deemed to be meeting the requirements of API 653-1995. It is recommended that HYDRO conduct within the next 2 years a further detailed inspection of the tanks and in particular an ultrasonic thickness survey of the tank floors.

As part of the tank inspection program, HYDRO refurbished the tanks – interior cleaned, floor painted; reshaped the dyke, installed a new dyke liner throughout and installed new piping within the dyke area. The exterior of the tanks was painted in 2004.

From an external observation, the tanks appear to be in good condition and should be serviceable for a further 15 years use.

The exteriors of the fuel storage tanks were recoated approximately three years ago. This coating was found to be in good condition and no signs of surface corrosion were noted during the inspection. As well, no significant pitting due to earlier corrosion was noted during the inspection. In general the exterior of all three fuel storage tanks were found to be in good condition.

All three tanks have proper ladders with climber safety systems. The climber safety system consists of a rigid rail attached to the rungs of the ladder at equal intervals. Fall arrestors, lanyards and harness are fastened to the climbers for fall arrest. The ladders were generally in good condition. However, HYDRO site personnel indicated that three (3) rungs at the top of the ladder of tank “35b” are missing welds on the inside of one rail. We recommend that these rungs be welded and the area affected by welding recoated.

The landing platforms on the top of the tanks were found to be in good condition and had proper handrails installed. As well, a static fall arrest lifeline has been installed between the landing platforms at the top of the ladder and the vent stack in the centre of the tank.

Each storage tank is fitted with a float and tape level gauge, a conductivity level switch, a differential pressure level transmitter, a temperature gauge and two grounding cables. All instrumentation equipment appears to be in good working order.

It is our understanding that the containment dyke containing the three (3) oil storage tanks was replaced approximately three (3) years ago. At that time, HYDRO reported that a liner was installed, and the dyke was covered in gravel.

The dyke was found to be in generally good condition at the time of inspection. Three (3) of the dyke walls were in very good condition and the slopes are holding up well. However, the north wall of the dyke facing the fuel forwarding building did appear to be lower in elevation than the other three (3) dyke walls. As well, the slopes of this wall were not in as good a condition as the other three walls. The lower elevation of the wall allows water from the site to drain into the dyke. This combined with site personnel walking down the slopes of this dyke wall to access the oil storage tanks have resulted in some deterioration of this dyke wall. We recommend that the top of the dyke wall be raised to the same elevation of the other three dyke walls to prevent runoff from entering the containment dyke. Also, installation of access stairs on the north side of the dyke will help prevent slope deterioration caused by site personnel walking down the slope of the dyke (Photo: SVL-025).

A drainage pipe with a manually operated valve in the south-west corner of the property is currently used to drain the fuel storage containment dyke. The containment dyke is adequately graded to this outlet pipe. At the time of inspection, there was approximately 12 inches of water over the top of the outlet pipe. We recommend that site personnel regularly drain the containment dyke to help prevent buildup of excess water in the dyke and help prevent premature rot of the timber posts supporting the access platform for the outlet pipe. The bottoms of the tanks are elevated approximately two to three feet above the bottom of the dyke to prevent submergence in water and corrosion. As well, it was noted that a light standard has been installed on all four sides of the containment dyke and should provide adequate lighting for the tank lot.

During the inspection it was noted that the containment dyke liner around several of the round concrete pilaster pipe supports inside the dyke were not sealed and could allow leakage should a spill occur. In these locations, the clamps holding the liner in place are loose and the caulking around the top of the liner has failed. We recommend that the clamps around all concrete pilasters be retightened and caulking reapplied to the joints where necessary (Photo: SVL-026).

It was noted that the containment dyke liner was not visible around the concrete block surrounding the oil transfer piping entering the ground in the north-west corner of the dyke. It is therefore possible that there is not a proper seal between the concrete block and the containment liner. We recommend that an investigation be carried out to determine if the joint between the concrete block and the containment liner is adequately sealed (Photo: SVL-027).

6.4.2 Fuel Forwarding

The function of the fuel forwarding module is to provide fuel at a positive and constant pressure to the gas generator engines for combustion. An inspection was made of the fuel forwarding equipment contained in a building integrated with the spill containment dyke surrounding the tanks. The major equipment located inside the building consisted of the main pump and motor, the off-loading fuel pump and motor, the auxiliary fuel pump and motor, the electric fuel heater, fuel filters, pressure switches, control valves, regulator valve and the associated piping.

The pumps, valves and piping were checked for evidence of problems. Nothing significant was found and the equipment had a well cared for appearance. There is sufficient back-up pumping and valving to provide a low risk of failure to deliver fuel. However, there is only one fuel heater and a spare replacement element should be carried together with the necessary gaskets, etc.

The fuel forwarding area contains a motorized valve with position indication in each of the three fuel lines coming from the storage tanks. A local control panel permits the operator to select one of three tanks as a supply. The panel also contains the instrumentation for tank level alarms, including local annunciation for tank overfull. A common fuel line contains a recently installed Coriolis meter for accurate measurement of fuel consumption. A heater preheats the fuel. As well, a single filter is installed in-line within the common line.

All instrumentation is in good working order with the exception of the differential pressure switch on the fuel filter. This switch has had its sensing lines removed. HYDRO has opted to change the filter on a schedule correlated to fuel consumption. It is suggested that the differential pressure switch remain in service in case maintenance cycles are missed or the filter clogs more quickly than expected.

6.4.3 Fuel Piping

The installed system of above ground interconnecting piping and valves from the fuel forwarding building to the storage tanks allows for any combination of tanks to be filled or drained simultaneously. The condition of the piping system is good and should be reliable for a further 15 years of service.

The piping from the fuel forwarding building to the storage tanks is above ground. The piping from the fuel forwarding building to the power plant is underground and does not conform to current codes. HYDRO is currently replacing this piping with double-walled piping with vacuum monitoring. The interior pipe is 4 inch and the exterior pipe is 6 inch.

6.5 ELECTRICAL SYSTEMS

6.5.1 13.8 kV Switchgear

The switchgear serves to isolate the plant and its related systems electrically from the grid when it is not running or is down for maintenance. The switchgear and associated protective relaying systems provide protection to equipment and personnel during abnormal loading or fault conditions.

Switchgear is subject to deterioration over time due to breaker contact wear, arcing damage and insulation breakdown. A typical switchgear installation includes integral instrumentation transformers, which are also subject to insulation degradation. While generator breakers are infrequently called upon to interrupt heavy or short-circuit loads, the recommendations of the manufacturer should be followed with respect to inspections and maintenance schedules.

Switchgear should be replaced when no longer supported by the manufacturer, parts availability wanes and safety of personnel or equipment potentially becomes compromised as a result.

The 15 KV 3000A metal-clad walk-in switchgear assembly houses the 13.8 KV alternator circuit breaker, potential and current transformers, station service power fuse and the disconnect switch. HYDRO provided a copy of a report on a condition assessment of the Hardwoods and Stephenville 15 kV Switchgear and outdoor Bus Duct carried out by Acres in 1995. It is our understanding that most of the recommendations outlined in that report have been carried out. A new 15 kV metal enclosed switchgear assembly was installed in 1998. Switchgear & Controls Ltd, Markham Electric supplied the complete assembly. The alternator breaker, a withdrawable vacuum type breaker, was replaced in 1998 because of a short circuit developed at the bus duct. While a detailed inspection of the switchgear was not carried out in this study, the physical condition of the switchgear and the associated equipment appears to be in good condition. The typical operating life for switchgears and breakers could be assumed to be 35 - 40 years. With regular maintenance, the switchgear and the breaker should be able to operate normally for another 15 years or more. Replacement parts and services can be expected to be obtained locally or though switchgear equipment suppliers.

A regular maintenance program for the switchgear and its equipment should be followed. Attention should be paid to inspect the condition of the breaker contacts, check for arcing damage, check the operating mechanism of the breaker and conduct insulation tests for insulation breakdown.

The disconnect switch should be operated occasionally and a set of spare power fuse should be stored at site or readily obtainable upon emergency replacement.

HYDRO should apply infrared thermography to monitor temperatures and thermal patterns while equipment is running in full load to detect changes in temperature. Repair and/or replace any hot-spot area. Safety procedures must be observed during scanning because the enclosure doors will be opened for scanning. Arc flash labels should be posted at the switchgear cubicles to provide guidelines on personal protection equipment requirements. Another option is to install infrared scanning ports to allow scanning without opening the door.

A rain shield should be installed at the air vent to prevent rain and snow blowing into the switchgear enclosure (Photo: SVL-028).

The delivery time for a replacement switchgear and breaker could be in the area of 20-24 weeks. A back-up plan should be prepared to cater for a total failure (for example a fire) of the switchgear and/or breaker.

6.5.2 13.8 kV/600 V Station Service Transformer

The 750 KVA, 14.4 KV-600V dry-type transformer located inside the switchgear building enclosure appears to be in good physical condition. Results of tests carried out on the transformer over the years were not available for review during the visit. With regular maintenance and adequate ventilation, the transformer should be able to provide satisfactory service for the next 15 years.

The transformer and its accessories, such as the lightning arrestors, the surge capacitors and the cable connections should be part of a regular maintenance program. HYDRO could apply infrared thermography to monitor temperatures and thermal patterns while the transformer is running under load to detect changes in temperature. Repair and/or replace any hot-spot area. Safety procedures must be observed during scanning because the enclosure doors will be opened for scanning. Arc flash labels should be posted at the transformer cubicle to provide guidelines on personal protection equipment requirements.

The transformer insulation should be tested at regular intervals. Temperature inside the transformer cubicle should be monitored and additional ventilation may be necessary if the room temperature is too high. Over heating and overloading of the transformer will shorten the life of the transformer.

6.5.3 13.8 kV Bus Duct

The 13.8 KV metal enclosed non-segrated bus duct (Photos: SVL-029 & 030) connects the alternator phase bushings to the 13.8 kV alternator circuit breaker located in the 13.8 kV switchgear enclosure. The bus duct further connects the circuit breaker to the unit step-up transformers 13.8 kV bushings located in a low voltage termination box mounted on the transformer. The bus bar material is copper and the bus duct is enclosed. Two (2) sections of bus between the alternator bushings and the switchgear assembly and between the switchgear and the step-up transformer were replaced in 1998 due to a reported short circuit between two phases. The robust bus duct metal enclosure was replaced at the same time. With regular maintenance, the bus duct should be able to provide satisfactory service for the next 15 years.

Regular maintenance should include inspection for bus bar rusting and corrosion, insulator tracking and the physical appearance of the enclosure. The bolts at the joints should be re-torqued regularly. Infrared scanning of the bus bar, the joints and the terminations should be performed to identify hot-spots.

The bus duct at Stephenville has a history of corrosion and rusting. If it is necessary to replace the bus duct, cable duct should be considered. Cable ducts are gaining popularity over bus ducts because of their flexibility, and easier and cheaper to install. Providing that the design and specification of the cables are done correctly, cable duct may have less chances of having a phase-to-phase or phase-to-ground flash over caused by moisture penetration or moisture condensation inside the duct than non-segregated bus.

6.5.4 AC and DC Motor Control Centres

The motor control centres (MCC) provide protection and control for the auxiliary electrical devices for the gas turbine plant. There are two motor control centres - one for the 250V DC equipment and another for the 600V AC equipment. The MCC cabinets house the basic electro-mechanical devices such as circuit breakers, contactors and overload relays. The original MCCs were supplied by Westinghouse. Eaton/Cutler Hammer took over the MCC product lines from Westinghouse. Eaton/Cutler Hammer or other electrical equipment distributors can supply compatible replacement parts or replacement kits for any MCC up-grades. The operating handles of the MCC are capable of padlocking. This feature should satisfy HYDRO’s locking and tagging requirement.

Unless the operating philosophy of the motor control changes drastically, such as operating the motors with variable frequency drives (VFD), adding feedback monitoring and network interfaces that would require changes to the structure of the MCC wrappers (any changes to the MCC structure will require CSA re-certification), the existing MCC should not require to be replaced and should be capable of operation for a further 15 years.

In addition to regular inspection on the de-energized equipment, infrared thermography inspection should be performed on a regular basis with the equipment energized. Safety procedures must be observed during scanning because the enclosure doors will be opened for scanning. Arc flash label should be posted at the MCC to provide guidelines on personal protection equipment requirements.

6.5.5 DC System – Station Battery and Charger

The station DC system has to provide sufficient capacity to supply the various DC motors and DC powered protection and control systems.

Depending on the battery type, the station battery is subject to various forms of deterioration including: corrosion of posts, cables, hold-downs, and battery trays; cell damage due to severe discharge or overcharge conditions; high resistance connections; and reduced cell capacity. Routine maintenance will serve to detect and remedy these conditions, such that replacement is only required when the general condition deteriorates beyond the point that maintenance is ineffective or overall battery capacity no longer meets the plant requirements. Manufacturers typically specify a design life of 15 to 20 years for wet-cell type batteries, and recommend that the banks be replaced after this period of time.

Common charger and inverter failures include open or shorted rectifier diodes or deteriorated electrolytic capacitors. Replacement is a consideration if vendor support is no longer available, improved output characteristics are desired (i.e. reduced ripple, improved regulation) or the charger or inverter load changes considerably due to changes in the station.

There are three banks of batteries (125 Vdc and 250 Vdc) inside the battery room. The 125 V battery bank was replaced in 2005. The battery cells are in good condition. No leaks or cracks are visible. With regular maintenance, the batteries should be able to last for more than 15 years. The 250V and 125V chargers are Power Tronic, Type 668, Class “D” chargers (Photo: SVL-031). They are no longer being supported by the vendor.

The original inverter was supplied by CTS Canada. It failed and was replaced with a unit supplied by Pylon in 2004. Under normal operating conditions, the inverter should be able to provide satisfactory service for the next 15 years.

The regular battery and charger maintenance program should be followed. Defected cells/parts should be repaired or replaced as soon as they are detected. Re-assess the rating of the batteries and charger if there is a major addition of DC loads. A replacement program should be prepared to replace the chargers as the opportunities arise if the vendor does not continue to support the service of this type and model of charger anymore. The batteries should be able to operate satisfactory for the next 15 years.

6.5.6 Protection Relays and Synchronizer

The protective relaying systems provide protection to equipment and personnel during abnormal loading or fault conditions. Their functions must be sufficient to protect the generating unit against all harmful conditions that may develop and act quickly and appropriately to isolate the abnormal conditions from the system and the alternator. The synchronizing function is critical and requires accurate and reliable monitoring of voltage level, frequency and phase angle. It ensures bump less transition of the alternator to the on-line state, thereby minimizing machine stress and power system transients.

The measuring relays for the alternator protection system are electromechanical relays (Photo: SVL-032). For electromechanical relays, ageing of the moving surfaces (such as bearings and bushings for induction discs) due to corrosion or excessive wear can lead to failure of the relay. For measuring relays, ageing of components such as capacitors, resistors, coils and worn contacts are sources of failure. Ageing mechanisms include: corrosion and overheating of contacts; vibration on bearings; wear of bearing surfaces that have exceeded the number of design operations; and failure of insulation material in capacitors and other components due to ageing of the materials.

While a detailed alternator protection review and analysis is not within the scope of this study, a review comparing the existing protection functions with IEEE Std. C37.102-1995 IEEE Guide for AC Generator Protection is provided as follows:.

IEEE recommendations:

- Loss of excitation (40)
- Phase and ground fault (87G, 87GN, 51/59GN)
- Field fault (64F)
- Unbalanced current (negative sequence) (46)
- Over and under-voltage (59, 27)
- Over and under frequency (81)
- Stator thermal (49)
- System back-up (51V)
- Alternator turn to turn fault (61)
- Voltage balance (60)

Existing Protection Functions:

- Loss of excitation (40)
- Phase and ground fault (87G, 64G)
- Field fault (64F)

- Unbalanced current (negative sequence) (46)
- Over and under-voltage (59G, 27G)
- Over and under frequency (81)
- Stator thermal (49)
- System back-up (51V)

The existing protection provides adequate basic protection functions to protect the alternator. Compared with the IEEE Standard, the functions that are missing are the generator turn to turn protection (61) and the voltage balance relay (60). An alternator turn to turn fault is difficult to detect. Alternator differential relay will provide protection for alternator internal faults. Depending on the setting sensitivity of the alternator differential relay, it will provide some degree of turn to turn fault protection. The function of the 60 relay is to block the mis-operation of the relays using voltage as a restrain source. There will be costs to incorporate these two functions into the existing protection system. HYDRO's protection design engineer may want to review the scheme and decide whether the level of reduced risk will warrant the level of expenditure required.

Although the existing relays could provide adequate protection, the availability of any direct replacement of the electromechanical relays will be limited. Unless HYDRO has spare relays stocked in their system, it will be difficult or even impossible to obtain direct replacement relays from the manufacturers. The option of replacing the entire protection panel with digital protection relays should be considered because of the ageing considerations of the electromechanical relays, the unavailability of the replacement relays and the increased protection obtained through the multiplicity of advanced functions available in today's digital relays at relatively low cost.

The automatic synchronizing function is provided by the Bailey DCS system. The sync-check relay, PRS-250 is provided by Basler Electric. The design of the sync-check relay has not been changed for the last 15-20 years and is expected to remain that way unless a parts availability issue forces Basler to make a component change.

Historically, the failure rate of electromechanical relays is low (with good maintenance, some of the relays are still in service after 40 years or more) but some of the relay components will age and will fail eventually. The replacement parts and the skilled technicians that are knowledgeable enough to fix these relays are getting harder and harder to find. We suggest that a protection replacement budget and protection modification program should be prepared for the Facility. Replace the relays for the Facility when the opportunity arrives and possibly keep the replaced relays as spare for the other Facility for direct replacement.

With today's technology, one multifunctional digital protection relay could replace several electro-mechanical relays to provide the same protection functions. The GE Multilin Generator Protection Relay replaces the following existing protection functions – 40, 64,87G, 46,59,27,81, 49 and 51V (refer to relay function numbers above). A cost estimate has been provided for one multi-functional digital generator protection relay. If HYDRO's protection philosophy requires additional relays for backup or for another redundant scheme, the cost estimate will increase accordingly.

In the meantime, considering the age of the relays and the non fail-safe design of the electromechanical relays, it may be prudent to test the existing relays in a 2 or 3-year cycle rather than the 6-year cycle as recommended in the HYDRO maintenance program. In conversation with Craig Warren (HYDRO P&C Engineer), he indicates that more than once, the negative sequence relay operated immediately after the unit was put on line. We recommend the setting of this relay be reviewed and the relay tested and re-calibrated if necessary.

6.5.7 15 kV Power Cable

The power cables associated with the 750 kVA station service transformer (Photo: SVL-033) are cross-linked polyethylene (XLPE) insulated cables.

Medium voltage XLPE insulated cables were first installed in the late 1960's. The cable manufacturers and utilities expected the cables to perform reliably for 20-30 years. History has shown that the service life of some of these early cables was far shorter than expected. Many cables failed after only 10-15 years in service. It was later discovered that voids and contamination in the semi-conducting shields, as well as other design and manufacturing deficiencies, led to voltage stress concentrations within the cables. The elevated voltage stress, combined with moisture ingress into the cable structure created what are known today as water trees. These microscopic cavities degraded the insulation over time, ultimately causing the cable to fail. To reduce water tree growth, a special engineered insulating material designed to limit water tree growth called XLP-TR was commercialized in the early 1980's and has been performing reliably in service for over 20 years. Furthermore, the design, manufacturing practice and quality control of power cables have improved drastically within the last 20 years. The design life for the XLPE insulated cable is 20-25 years. The design life for XLP-TR (trees retarded) insulated cables is 30 years or more.

It is our understanding that the 15 kV power cables in the Plant were the original installations that dated back to 1975. The failure rate for power cables installed before early 1980s is high. Our recommendation is to replace the 15 kV power cables installed during 1975 with XLP-TR type insulated cables during the next major Plant shut down. For a 13.8 KV system, the power cables should be shielded and terminated with stress cones.

6.5.8 Motors

Properly selected and installed motors are capable of operating for many years with a reasonably small amount of maintenance. Routine maintenance should include inspection for dirt, corrosion, heat, noise, vibration and brush conditions; lubrication of bearings; measuring and trending of the winding insulation.

Motors located inside the buildings seem to be in good physical conditions. The motors located outside are covered with fine dust and show sign of corrosion. All motors should be cleaned, check for signs of corrosion, perform internal inspection, and open the conduit box to check for deteriorating insulation or corroded terminals. Insulation resistance (Megger) test and Polarization Index test should be incorporated into the maintenance program. Any damage parts discovered during inspection should be repaired and rebuilt. Well maintained motors should provide satisfactory service for the next 15 years.

6.5.9 Emergency Backup Diesel Generator

An emergency backup diesel generating unit was installed in 2005. The diesel generator was relocated from another HYDRO site. The diesel generator is a self contained package consisting of control panel, battery charger, etc. The 40 kW 600 volt AC diesel generator starts automatically on loss of the AC station service supply to the Gas Turbine and supplies power to a backup battery charger which in turn ensures the integrity of the 125 Vdc supply to the Gas Turbine for protection and control purposes. The diesel generator also provides a backup AC supply for one of the air compressors. The diesel generator is in excellent condition.

6.6 CONTROL AND INSTRUMENTATION SYSTEMS

6.6.1 Control Module

The gas turbine control module features an ELSAG Bailey INFI 90 DCS installed in 1999 to replace a mainly electromechanical relay control system. The DCS system incorporates three subsystem hot-swappable controllers with redundant backup controllers. The DCS internal network utilizes a redundant communication module. The operator interface uses a PC running PCV and QNX software. The PC is connected to a color screen which displays system graphics and to a keyboard for operator input. A communication link connects the PC to a SCADA system which allows remote control and monitoring of the gas turbine from the Energy Control Center in St. John’s, Newfoundland.

There have been some failures recently of input channels. Stantec has requested a report from HYDRO on the number of failures and the availability of spares. It appears that there may be no spares since the operator has rewired the inputs from the failed channels to channels which are working, rather than replace the faulty input module itself. ABB still sells these input cards and will support them for an additional 10 years once the product has been discontinued. In addition, newer technology is available that will directly replace the older technology and use the same footprint. Stantec recommends replacing faulty modules since the failure of one or more channels could be an indication that other channels are soon to fail.

The interface computer (PC) was out of service at the time of the site visit due to a motherboard failure. There have also been video card and hard drive failures in the past. A similar PC from the operator’s home is temporarily replacing the interface computer. The interface computer is an older vintage and as such has very little memory capacity and will not run today's software. There is significant risk in not replacing the existing PC since it is older technology and does not have a ready availability of parts. ABB has issued a quotation to HYDRO P&C (copied to Stantec) for a new PC with the latest PCV and QNX software. The new PC will also give HYDRO the ability to do more extensive trending. Stantec strongly recommends the PC and software upgrade be implemented.

The power supply system for the DCS is obsolete. Stantec recommends replacing the power supply system in order to extend the life of the control system out 15 years. ABB has provided a quotation to HYDRO P&C (copied to Stantec) for a new power supply.

Conditions in the control room were quite hot and humid at the time of the site visit. In addition to the hot weather during the site visit there are also many sources of heat in the room. Heat and humidity are known to speed the deterioration of electronic components. Stantec recommends the installation of an air conditioning unit in the control equipment room.

6.6.2 Interposing Relays

In August 2006, P&C staff discovered a problem with the control system design. There were at least 8 relays with contact that were not rated for the current which was being interrupted. The problem was detected when welded contacts were found on the relay which controls the fuel recirculation valve. Pitting and carbon deposits may have been forming on some or all of these relays resulting in increased switch bounce and high impedance contacts. High impedance contacts would cause in a reduction of power to the device being controlled. Partial welding would result in late break operation. The overall result of using the incorrect relays could have been inconsistent control, possibly with shutdowns or non-starts.

6.6.3 Vibration Monitoring

The existing vibration monitor by IRD was installed in 1975. The monitor appeared to be functioning well at the time of start up during the site visit. Vibration was a little high on the lower speed range but dropped down as the speed was increased.

Some vibration problems (non specific) were reported in 1993 but the actions were not recorded in the Station Log. There were no further problems recorded until 2007; however, some of the alternator trips in the log are not descriptive and could have been caused by vibration problems or vibration monitoring equipment faults.

In April 2007 the alternator exciter was giving a vibration trip. Initial troubleshooting seemed to indicate the accelerometer was at fault but continued testing included a shaker table test indicated that the accelerometer was calibrated correctly. There was a true vibration issue, not a faulty monitoring problem.

Operations staff and P&C are of the opinion that the vibration monitoring equipment needs to be replaced. Stantec has not seen evidence of troubleshooting activities which support the conclusion that the monitoring equipment is faulty. That having been said, the equipment is obsolete and could fail during the next 15 years. According to P&C staff, HYDRO has an approved capital budget item to replace the existing vibration monitors at both sites in 2008. The existing transducers are functioning well and will not be replaced. The transducers are still available on the market. It would be advisable to have a few spares at each site.

6.6.4 Temperature Monitoring

Temperature monitoring is an integral part of the DCS system whereby critical temperatures are brought into the DCS either as analog inputs from RTDs and thermocouples or as discrete signals from temperature switches. Bearings, windings, glycol, oil, fuel, and air are some of the quantities being measured. Critical temperatures can cause alarming, power limiting or unit shutdown as appropriate.

HYDRO staff reported that the type J and K thermocouple wire and terminal blocks in various junction boxes were replaced during the controls upgrade in 1999. There are sufficient temperature monitoring instrumentation and indications both in the field and at the DCS according to operations and P&C staff. There were no deficiencies observed in the temperature monitoring equipment at the time of the site visit.

Faulty temperature instrumentation has been replaced in the past on an as-needed basis. In 1994 and 2002, thermocouples were replaced on Gas Generators A and B; however, the Station Log does not specify which units or sub-system was at fault. In 2005, an exhaust thermocouple was giving a bad quality signal on Gas Generator B. Again, the Station Log does not specify what action was taken.

Temperature element failures are likely to occur over the next 15 years. One approach which HYDRO could take with regards to thermocouple and RTD maintenance is to replace the elements on each sub-system at the time of a major overhaul. Elements which can be easily changed and have no shutdown initiation can be replaced as they fail. Dual element thermocouples are likely not a cause for concern since the second element is available when the first one fails. Existing spares should be reviewed.

Temperature switches have not shown any failures at Stephenville. Exact replacements will not likely be available over the next 15 years, but it is very easy to source an equivalent switch with a compatible temperature range. Temperature switches are dry contact devices so there is no issue with supply voltage level. Installation detail will not likely be an issue as the switches are normally surface-mounted or mounted with a standard pipe size and thread type. Switch size should not be a problem since instrumentation generally shrinks in size over the years and will therefore fit in the footprint of the device being replaced.

6.6.5 Instrument Calibrations

Stantec could not find any evidence that transmitters and switches are being periodically calibrated. Operations could not recall these activities being done. Stantec recommends routine calibrations of all instruments. Initially all instruments should be calibrated and the frequency of recheck should be dependent on the stability of the instrument. Non stable instruments should be replaced.

6.6.6 Control Valves

There are several control valves including a temperature regulating valve in the glycol system, a pressure controlled valve in the lube oil system, and control valves in the fuel system. These valves are original equipment with the exception of the motorized valve at the fuel tank. As such, it may be difficult to get spare parts and support, although the station logs have indicated replacing internals in some of these valves. NLH should examine the design conditions for these valves to determine if the conditions can be met today in a package that is a direct replacement. If not, some redesign of piping will be required should a valve have to be replaced. This is best determined in advance so a plan can be generated and sufficient spares stocked. Stantec recommends one spare for each of the original equipment control valves.

Anti-Icing Valve

There have been several incidents of shutdown due to anti-ice valve failure. Stantec recommends at least making the response to an anti-ice valve operation a power limited condition rather than a full shutdown. The logic can likely accommodate this change.

Fuel Tank Motorized Valve

The motorized valve on the fuel tank is new and works well with one exception. There appears to be a deficiency in the logic in which the valve will not open until a certain time delay after an engine has successfully completed its start up sequence. Once the engine has started it is consuming fuel oil while the motorized valve is still closed. Eventually it uses all of the fuel in the line between the engine and the fuel tank, and the unit shuts down. Logic changes appear to be in order to correct this problem.

6.6.7 Remote Control and Monitoring

Remote control and monitoring of the Stephenville Gas Turbine at the Energy Control Centre (ECC) in St. John's is accomplished through a SCADA system interface to the DCS. The SCADA system was recently upgraded in 2006. The SCADA system is not part of the Condition Assessment Study scope.

P&C personnel have indicated that future upgrades are being considered. In particular, data transferred from the Gas Turbine sites to ECC could be expanded and stored on a PI historian at ECC. According to P&C personnel, HYDRO has a central group that deals with SCADA maintenance and upgrades.

6.6.8 Junction Boxes

Some of the junction boxes mounted on the exterior of the Gas Turbine enclosure (Photos: SVL-034 & 035) have corroded terminal blocks and are partially opened to the weather. The corroded terminal blocks need to be replaced in 2007 or 2008. The junction boxes should be made water tight by installing a weather tight box around each existing box. There is one installation like this already existing on the unit. The new box is surface mounted around the existing one. This would be the cheapest and easiest solution.

Both turbine units still have the original on-engine electrical junction boxes. It is recommended that these boxes be moved off-engine, to isolate the terminations from engine vibration and heat.

6.6.9 General Comments

There is no guarantee that any particular instrumentation component will last another 15 years without repair or replacement. However, most of the instrumentation will have suitable replacements.

It would be a beneficial project for HYDRO to create a specification sheet for each piece of instrumentation. Nameplate data, set points, ranges of operation, flange rating, face to face dimensions, etc, could be recorded. Where nameplates and other information are unreadable or unavailable, the exercise of creating the spec sheets will require a bit of research but could be done under non-breakdown conditions.

Having this information available electronically will make sourcing of suitable replacement instruments easier. Identifying replacements could be done in advance to build a spares inventory. The spec sheets could identify several instruments which could use a common spare. Maintenance notes could be added to the spec sheets to track repairs and calibration.

Some of the more complicated retrofits, such as a control valve which requires piping modifications, could be done on a project basis when the valve nears the end of its serviceability.

Stantec is not aware of the program used by HYDRO for the routine calibrations or testing of switches. HYDRO should confirm that the current set points of all instrumentation are in line with manufacturer’s original operational design set points. Further, HYDRO should confirm that all instrumentation is functioning properly.

Spares should be stocked for each type of instrumentation device when delivery lead times are long.

6.7 BUILDINGS

6.7.1 Control Building

The existing control building is a single story prefabricated steel structure supported by cast-in-place concrete foundations and with a concrete slab on grade. The exterior building envelop consists of sheet metal siding and roofing.

Based on the degree of fading and corrosion of the existing cladding and roofing it appears that they are original and therefore were likely installed in 1975 when the gas turbines were installed. The typical design life of this type of material is between 35 and 40 years of age. If this cladding is original, it is nearing its design life.

The cladding is generally quite faded and corrosion is appearing in many places over all the buildings cladding. Typically corrosion of the cladding is evident along the bottoms of the cladding panels, there are many areas where spots of surface corrosion are developing on the exterior of the panel and in many places small pin holes have developed in the coating of the cladding and corrosion is visible in these locations. Corrosion of the sheet metal roof is also evident along the entire perimeter of the building. Based on the condition of the existing cladding and roofing it is likely that these items will have to be replaced within the next five (5) years (Photos: SVL-036 & 037).

There are also several locations where the existing cladding requires immediate repairs to prevent water intrusion into the wall system. The cladding on the corner adjacent to the air tanks on the rear of the control building is damaged and could allow water intrusion. The cladding must be properly sealed around the air piping penetrating the cladding and there are two holes in the rear of the building which are approximately 2” in diameter which should be properly sealed.

The windows in the building are in acceptable condition. However, the exterior wood fascia is in need of painting this year. The interior of the building is generally in acceptable condition and no significant issues were noted. The roof structure was visible in two locations where ceiling tiles had been removed. The roof structure which was visible for inspection was found to be in good condition.

We have noted two areas that are potential safety hazards. The steps up to the platform containing the controls for the gas turbine units are quite large with a rise of 12 ½”. The National Building Code does not permit a step over 7 ½” in height. We therefore recommend that intermediate steps be installed at these locations (Photo: SVL-038). In one location at the south-east corner of the room the step will have to be removable since an electrical trench with removable covers is located directly below the step (Photo: SVL-039). As well, one of the steel covers for the exterior electrical trench at the rear of the building is not properly supported or fastened down. A person can easily trip over the cover or step through the cover and it presents a safety hazard. We recommend that this particular item be addresses as soon as possible.

6.7.2 Fuel Forwarding Building

The existing fuel forwarding building is a single-story prefabricated structure located on the south-west corner of the property. The building is approximately 20' x 28' in plan and 8' high. The exterior of the building consists of sheet metal siding and roofing with sheet metal liner panels on the interior of the building. The building is supported by cast-in-place concrete foundations and has a concrete slab on grade floor approximately 52" below the exterior finished grade. This arrangement provides approximately 12' of head room inside the building. The building is ventilated by a single exhaust fan and supply louvre.

During the site inspection, it was noted that there was a strong diesel odour in the building even with the door open and the exhaust fans running for some time before entering. The likely cause of this odour is the drainage system in the building. Currently, the floor slopes to in-floor channels that then drain to a sump which retains some liquids. The fact that the sump does not completely drain is likely contributing to the fumes and odour inside the building. As well, this sump drains through underground piping to a large concrete sump to the south of the building inside the fuel storage containment dyke. This exterior sump does not have an outlet and simply stores all material collected from the building. HYDRO site personnel indicated that this sump is pumped out roughly on a yearly basis. It is quite likely that fumes from this sump are migrating back into the building through the underground piping. It is unknown if a p-trap has been installed in the underground piping. If a p-trap was installed, it is likely that it is not functioning properly since it can dry out when there are low volumes flowing through the drainage system. Given that there is no water supply in the building, it is very unlikely that a p-trap primer has been installed to prevent dry-out of the p-trap. As well, anything that does collect in the p-trap likely has a high concentration of hydrocarbons and will contribute to the odour in the building.

The existing concrete dyke at the off-loading station is in good condition with no visible cracking. This dyke drains, via underground piping, to the storage sump noted above inside the fuel storage containment dyke. Site personnel indicated that the drain in the concrete dyke is plugged before beginning any off-loading of diesel fuel to help contain any spills. However, it was noted that the bleed valve used to remove air from the system is not located over the containment dyke. Therefore, any diesel fuel which is released through this valve through the bleed process falls to the grade and is not captured by the concrete containment dyke. We therefore recommend that the existing piping be modified so that the bleed valve is located over the concrete containment dyke thus any diesel fuel escaping from the system can be properly contained (Photo: SVL-040).

It was noted that the area surrounding the concrete off-loading dyke was just gravel. We recommend that this area be paved to help contain and facilitate clean-up of any minor spills that may occur when the off-loading hose of the delivery truck is being hooked up to the oil transfer system (Photo: SVL-041).

It was noted that the existing gutters on the fuel forwarding building are badly corroded with perforations in several areas. These gutters and downspouts require full replacement (Photo: SVL-042). Based on the degree of fading and corrosion of the existing cladding and roofing, it appears that they are original and therefore were likely installed in 1975 when the gas turbines were installed. The typical design life of this type of material is between 35 and 40 years of age. If this cladding is original, it is nearing its design life. The cladding is generally faded and light corrosion is appearing in several places. The west wall of the building is in the worst condition with more advanced corrosion at the corners. We recommend that the cladding on the west wall be replaced in the next year and the remainder of the cladding and roofing will likely have to be replaced within the next five (5) years (Photo: SVL-043).

The steel structure was not visible during our site assessment. However, the interior ceiling and wall liner panels are in good condition and there are no signs of corrosion or water staining. This indicates that there has been limited water leakage and the structure of the building is likely to be in good condition.

As part of this assessment, we also reviewed the condition of the existing slab on grade, concrete foundation wall and concrete equipment plinths. All were found to be in generally good condition with minor shrinkage cracking in the floor slab and foundation walls.

At the July 17, 2007 Kick-off Meeting, Stantec was asked to consider whether the building should be classified as a hazardous location due to the diesel oil odours and the fact the interior floor is approximately 52” below the exterior finished grade.

A Class 1 hazardous location is one in which flammable gases or vapours are or may be present in the air in quantities sufficient to produce explosive gas atmospheres. Class 1 locations may be further divided into three Zones based on the frequency of occurrence and duration of an explosive gas or atmosphere. Zone 0 is a location in which explosive gas atmospheres are present continuously or are present for long periods; Zone 1 is a location in which explosive gas atmospheres are likely to occur in normal operation; Zone 2 is a location in which explosive gas atmospheres are not likely to occur in normal operation and if they do occur they will exist for a short time only.

API Recommended Practice 505, Section 5.2.1 identifies Class III liquids as having a flash point above 60C (140F). Diesel Oil and Fuel Oil #2 have flash points of about 77C (170F) ie they are

Class III liquids. Article 5.2.4.1 says: “Class III liquids normally do not produce vapours of sufficient quantity to be considered for electrical classification purposes. Class III liquids will release vapour in the flammable range at their surfaces if heated above their flash points, but the extent of the classified location ordinarily will be very small and near the point of release”.

With a well applied maintenance program, the possibilities of leaks from pipe joints and valve heads are low. Also considering the vapour from the diesel fuel is heavier than air, we could expect any vapour will be settled towards the floor. The diesel fuel is a “combustible liquid”, not a “flammable liquid”. Our interpretation is that with adequate ventilation, the fuel forwarding building could be considered as a non-classified area and the electrical equipment and wiring does not have to comply with the requirement for a Zone 1 or Zone 2 area usually applied to a hydrocarbon pumping station.

We recommend that HYDRO review the buildings ventilation system and possibly install additional air intake louvers and ducting to convey incoming air to foundation level and provide adequate ventilation to the building (API RP505 outlines a number of methods for demonstrating or meeting the requirement for “adequate ventilation”). The proposed inlet air system should be at the diametrically opposite wall from the existing ventilation fan. HYDRO should also consider the need for a larger or additional exhaust fan. As well the sump in the building should be cleaned on a more frequent basis.

6.7.3 Parts Storage Shed

The parts storage shed located in the north-west corner of the facility was also reviewed as part of this assessment. The storage shed is constructed of timber framed walls and roof on a concrete slab on grade. The building envelop consists of an asphalt shingled roof and vinyl siding.

The existing asphalt shingles have been installed over old shingles and are in acceptable condition. However, the shingles are weathered and will likely require replacement within the next five (5) to seven (7) years (Photo: SVL-044). The vinyl siding is in acceptable condition.

The existing overhead door is showing signs of rot and is in poor condition. We recommend replacement of the door with a new commercial grade overhead door complete with proper weather stripping. The existing entry door and frame are also in poor condition. There are large gaps along the bottom of the door which can allow rodents, snow and water to enter. The door is also quite difficult to operate. We recommend that the existing man door and frame be replaced with a new commercial grade door and frame with proper weather stripping and commercial grade hardware (Photo: SVL-045 7 046). The existing windows in the west and east sides of the building are in acceptable condition, but painting of the exterior wood fascia is required.

The interior drywall and plywood sheathing is in generally good condition with only one crack in the drywall which is located over the electrical panel on the south-east corner of the building. The concrete slab on grade was also reviewed and was found to be in good condition. The timber framing for this structure was not visible or accessible so we cannot comment on the condition of this item.

It was noted that the existing brackets to support the ladder were damaged and were quite high. We recommend that these brackets be replaced with new ones installed lower on the wall to make storing the ladder easier and safer. HYDRO site personnel also indicated that rodents were entering the storage shed and chewing up the filters stored in this building. Installation of a new man door and overhead door will minimize the number of places for rodents to enter. However, overhead doors are difficult to seal completely and consideration should be given to installing rodent proof metal cabinets for storage of the filters (Photo: SVL-047).

6.7.4 Waste Oil Storage Shed

The existing waste oil storage shed (Photo: SVL-049) located just east of the control building is an old transportation container converted to a shed. The shed has a steel exterior with timber framing on the interior. A timber-framed roof with asphalt shingles has been added to the container. The roofing and door of this shed are in very poor condition and are in need of replacement (Photo: SVL-048). The shed is not equipped with any ventilation, fire detection or suppression systems.

Given the timber construction of the shed, the waste oil stored in the shed, the high temperatures noted during warm weather and lack of fire alarm or sprinkler system, we recommend that the waste oil storage shed be relocated a minimum of 100 feet from the existing control building for safety purposes. Given that waste oil is stored in this structure, it is advisable to relocate the waste oil storage shed inside the oil storage containment dyke to contain any spills that may occur. Based on the condition of the existing shed, we recommend that this structure be replaced with a new non-combustible structure such as a new steel transportation container.

6.7.5 Emergency Back-up Diesel Generator Building

The existing diesel generator building is a single-story structure that is approximate 150 square feet in size. The exterior of the building consists of vertical sheet metal siding and asphalt shingle roofing. The building is supported by cast-in-place concrete foundations and has a concrete slab on grade. For oil containment, the building has a 150 mm high containment wall that extends up from the floor slab around the perimeter of the building. The wall is approximately 65 mm high near the door. The interior of the building is finished with painted plywood.

The building was built in 2005. The exterior cladding, roofing and doors on the building were found to be in good condition and no deterioration or corrosion was noted. The concrete slab on grade and interior plywood finishes were also found to be in good condition. An exhaust fan and louvre have also been installed to provide ventilation for the building.

6.7.6 General Comments

Only visual inspections were carried out as part of this assessment. Not all structural components were visible or accessible at the time of inspection. No non-destructive or destructive testing was carried out on any of the structures noted above as part of the inspection. Therefore this assessment should not be considered an exhaustive inspection of all civil/structural components. As well, it is important to note that no detailed analysis was completed as part of this assessment to determine the adequacy of different structures for their purpose.

6.8 ENVIRONMENTAL

The Condition Assessment Study addressed several environmental issues as they relate to the Stephenville site, specifically soils contamination and air emissions.

Soil Contamination

A review of several environmental reports provided by HYDRO indicates there have been a number of spills and leaks of petroleum products at the Stephenville site over the past 30 years. The petroleum products include #2 diesel fuel, lubricating oils and transformer oils. These spills and leaks resulted in soil contamination at various locations including the diesel fuel bulk storage tank area and the gas turbine / terminal station area. The following are a few examples of recorded spills and leaks:

- In 1991 an oil/water separator overflowed and impacted surrounding soils.
- In 1992 a diesel fuel spill of approximately 18,630 Litres due to mechanical failure.
- In 2000 during diesel fuel bulk storage tank upgrading there was remediation of contaminated soil in the vicinity of the leveling valve at Tank 1. Remediation was also conducted in the offloading area during the storage tank upgrading.

In all cases, these spills and leaks were cleaned to the satisfaction of the Department of Environment and confirmatory sampling revealed no unacceptable levels of impacts in the remaining soil.

Since 2001, HYDRO has initiated a number of environmental studies to investigate these impacts. These studies include:

- Jacques Whitford Phase I Environmental Site Assessment in 2002
- Jacques Whitford Phase II Environmental Site Assessment and Health and Screening Level Ecological Risk Assessment in 2006

The Jacques Whitford 2006 Study concluded that under existing conditions and for the identified concentrations of Chemicals or Contaminant of Concern (COC) found at the site, the potential for unacceptable risks to human health and ecological health is not likely. While petroleum hydrocarbons were detected in a number of soil samples and in several monitoring wells, their concentrations were well below unacceptable levels. The Jacques Whitford 2006 Study also tested for numerous other soil and water contaminants and while concentrations of a number of contaminants were detected their concentrations, with the exception of zinc, were well below unacceptable levels.

The Stephenville site, as of 2006, had an excellent soils environmental record.

Air Emissions

The gas turbine produces air emissions related to the combustion of diesel oil. The exhaust emissions are not filtered or treated. There is no Continuous Emissions Monitor System (CEMS) on either exhaust stack. The various HYDRO inspection check lists included in Appendix 5, do not list exhaust stack emission manual sampling as an activity. Data on stack(s) emissions testing that may have been conducted by HYDRO in the past was not available for review.

Exhaust emissions from the gas turbine fall under Newfoundland and Labrador Regulation 39/04, Air Pollution and Control Regulations (O.C. 2004-232). The Regulations list limits on the concentration of air contaminants due to all emitting sources. The concentrations are defined by periods of time during which the concentrations exist. It would appear that the present operational mode of the gas turbine, as predominately synchronous condenser operation, would be within the criteria listed in the Regulations. If the predominant operational mode in the future is generation on a somewhat continuous basis, HYDRO should be aware of the potential application of the air contaminant limits in the Regulations.

The Regulations state that an owner or operator who installs a new or modified emission source shall employ the best available control technology with respect to air emissions. This requirement however does not apply to parts replacement but would likely apply to the installation of a new gas turbine.

The Study did not take an exhaustive look at air emission issues at the Stephenville site. The issue of air emissions is noted in this Report for the express purpose of making the reader aware that any future significant generation operational mode change or significant work carried out at the site, as a follow-up to this Report, depending on the nature of that work, could involve the application of the criteria in the Regulations.

7.0 GAS TURBINE FACILITY 15 YEAR LIFE EXTENSION OPTIONS

7.1 GENERAL

The primary focus of the Study involved a condition assessment of existing Gas Turbine Facility equipment in order to determine which components may require refurbishment, repair or replacement due to equipment ageing effects, obsolescence or maintenance practices in order to provide reliable operation over the next 15 years. The HYDRO Request for Proposal (RFP) included the following work scope:

- Assess both sites for potential problems in continuing to operate the Facilities as they presently exist for the next 15 years. The Study will recommend solutions with associated cost estimates for maintaining and running the Facilities as reliable generating units.

In addition, the RFP required that the Study evaluate two other options for redeveloping the sites as follows:

- Option 1 - Replace the major equipment items and systems with new at one site. Existing infrastructures would be utilized where considered to be suitable for continued long term use. The components removed would be used as spares for the other site.

- Option 2 - Replace major equipment items and systems with new at both sites. Existing infrastructures would be utilized where considered to be suitable for continued long term use.

In order to address these requirements, the Study identified and provided cost estimates for the following base cases and options:

Base Case:

- Base Case 1 - Refurbishment of the existing Gas Turbine Facilities at Hardwoods
- Base Case 2 - Refurbishment of the existing Gas Turbine Facilities at Stephenville

Replacement Options at one or both sites:

- Option 1 – New Gas Generators (Engines) & Power Turbines
- Option 2 – New Alternator / Exciter
- Option 3 - New Gas Turbine
- Option 4 - New Dynamic VAR Compensator

Temporary Gas Turbine Rental

- To provide backup for MWs or MVARs while refurbishment or replacement work is underway at a site

This section of the Report will provide an overview of the technical aspects of the Base Cases and the Options as well as the costs associated with each. **The costs are summarized in Appendix 6.** Costs are considered to have an accuracy of (+/-) 30% and serve as a comparison of the relative costs of each Option to the Base Cases in the life cycle cost analysis that follows in Section 8.0. If HYDRO decides to proceed with either the Base Case or any of the Options, a more in-depth detailed capital cost estimate should be developed.

7.2 BASE CASE – REFURBISHMENT OF EXISTING GAS TURBINE FACILITIES

7.2.1 Hardwoods Gas Turbine Facility Refurbishment Recommendations

Report Section 5.0 provided a condition assessment of the existing equipment and structures at the Hardwoods Gas Turbine site. The various refurbishment recommendations contained in Section 5.0 along with associated costs are summarized in a spreadsheet included in Appendix 6. The following is a summary of the costs on an equipment or structure basis.

Table 1
Hardwoods GT Facility Refurbishment Costs
(2007 Costs)

Item	Equipment / Structure	Cost (Cdn$)
1	Gas Generator Engines / Power Turbines Equipment	$1,263,720.00
2	Inlet Air Systems A & B	62,300.00
3	Exhaust Stacks A & B	95,000.00
4	Glycol Cooler for Main Lube Oil	9,500.00
5	Gas Generator / Power Turbine Enclosures A & B	22,600.00
6	Alternator and Excitation System	2,122,000.00
7	Alternator Enclosure	10,600.00
8	Fuel Oil System	45,250.00
9	Electrical Systems	123,100.00
10	Control & Instrumentation Systems	70,100.00
11	Buildings	44,700.00
13	Miscellaneous HYDRO Work on Ongoing Operational Issues (labour & materials)	250,000.00
	Sub-Total:	$4,118,870.00
	HYDRO labour & overhead costs relative to Items 1 – 13 (assume 8% of sub-total)	329,510.00
14	Spare Parts (common to both Sites)	58,500.00
	Total:	**$4,506,880.00**

Commentary follows on each category of costs:

1. Gas Generator Engines / Power Turbines Equipment

   Refurbishment costs for this category were provided by Robin Sipe of S&S Turbines Services Limited. Mr. Sipe has extensive experience servicing Olympus C engines. The engines would be removed and reinstalled by S&S Turbine's personnel and shipped to Fort St. John BC for refurbishment. Approximately 90 days turn around time would be required to refurbish and test run an engine at the Fort St. John facility. S&S Turbines can provide, at HYDRO's discretion, an engine on a temporary basis to replace an engine shipped to Fort St. John. With a rental engine on site, the engines would be shipped piecemeal such that each site always has 2 engines in service. The costs include replacing the ignition exciters, the speed governors and fuel valve assemblies. It should be noted that previous refurbishment work on a single engine in 2000 by another service provider was at a substantially higher cost approaching $1.1 million.

   The power turbines will be thoroughly inspected, when an engine has been removed, and refurbished as required. The cost estimate for the power turbine refurbishment anticipates minimal refurbishment work based on observations during the site visits. The condition of the power turbines will be better known when removed from the enclosures. There could however be additional costs involved following a thorough examination of the power turbines, following the removal of the gas generator engines. There is also a cost included to dismantle and inspect the power turbine clutches.

2. Inlet Air Systems A & B

   These costs include a number of miscellaneous civil refurbishments to the inlet air systems on each end of the Gas Turbines. Refer to Appendix 6 for details. The recommended refurbishments are for structural integrity and safety reasons. The civil cost estimates were derived from the RS Means 2007 Cost Estimating Data Books adjusted to reflect the construction scene in Newfoundland and Labrador.

3. Exhaust Stacks A & B

   These costs include a number of miscellaneous civil refurbishments to the exhaust stacks on each end of the Gas Turbines. Refer to Appendix 6 for details. The recommended refurbishments are for structural integrity and safety reasons. The civil cost estimates were derived from the RS Means 2007 Cost Estimating Data Books adjusted to reflect the construction scene in Newfoundland and Labrador.

4. Glycol Cooler for Main Lube Oil

   The costs cover the refurbishment of the existing glycol cooler. Refer to Appendix 6 for details. The civil cost estimates were derived from the RS Means 2007 Cost Estimating Data Books adjusted to reflect the construction scene in Newfoundland and Labrador.

5. Gas Generator/Power Turbine Enclosures A & B

   The costs cover the removal of corrosion and re-coating the enclosures A & B where required. Also included are modifications to the man doors on each enclosure. The civil cost estimates were derived from the RS Means 2007 Cost Estimating Data Books adjusted to reflect the construction scene in Newfoundland and Labrador.

6. Alternator and Excitation System

   As discussed in sub-section 5.3.3, due to the absence of electrical testing and visual inspection records on the Alternator over its 30 years of service, it is not possible to determine the present condition of the alternator and exciter and make an assessment of its life expectancy and reliability over the next 15 years. In order to determine the present condition of the alternator and exciter, certain basic electrical tests and visual inspections are necessary. Therefore, the costs in this category include: (i) conducting electrical tests on the stator, rotor and exciter with the alternator in its enclosure (ii) removing the alternator or as a minimum the rotor from its enclosure and carrying out visual inspections and other electrical tests on the stator and the rotor (removed from the stator). The cost estimate assumes major refurbishment work on the alternator and the carrying out the necessary refurbishment work at a supplier's shop. The estimate should be considered a worst case upper end cost for alternator refurbishments. Input to the refurbishment estimate was provided by MAN TURBO.

7. Alternator Enclosure

   The costs cover the removal of corrosion and re-coating of the enclosures where required. Also included are modifications to the man doors on each enclosure. The civil cost estimates were derived from the RS Means 2007 Cost Estimating Data Books adjusted to reflect the construction scene in Newfoundland and Labrador.

8. Fuel Oil System

   These costs include a number of miscellaneous civil refurbishments to the oil storage tank. Refer to Appendix 6 for details. The recommended refurbishments are for structural integrity and safety reasons. The civil cost estimates were derived from the RS Means 2007 Cost Estimating Data Books adjusted to reflect the construction scene in Newfoundland and Labrador.

9. Electrical Systems

The Hardwoods electrical equipment was generally in good condition and should perform reliably over the next 15 years. Appendix 6 lists a number of refurbishment recommendations and associated costs for HYDRO's consideration. Pricing of the listed equipment was sourced from equipment suppliers. Costs associated with the recommended cabling modifications are at best a ballpark estimate as the detailed work to identify the number of affected power cables, their lengths and routing was not included in the scope of this Study. A more detailed evaluation of the extent and costs associated with replacing and installing the power cables in a separate compartment (item 38) is best left to HYDRO.

10. Control & Instrumentation Systems

The ELSAG Bailey INFI 90 DCS system installed in 1997 appears to be working relatively well. While there are currently shortcomings in the existing software/hardware, the storage of data and trending capability, the equipment modifications proposed by HYDRO as outlined in sub-section 5.6.1 should address current problems and improve system capacity and reliability for a further 15 years. In addition, the supplier of this equipment will support the equipment for years to come. Refer to Appendix 6 for further details on other proposed recommendations and costs.

11. Buildings

This category of costs addresses recommendations for refurbishment work on various buildings on the site. Buildings include: (i) Control Building (ii) Fuel Unloading Building (iii) Fuel Forwarding Building (iv) Auxiliary Module Building (v) Maintenance and Parts Storage Building and (vi) High Voltage Switchgear Building. The refurbishments include roofing, cladding and other maintenance work on the Buildings to ensure their structural integrity for a further 15 years. The civil cost estimates were derived from the RS Means 2007 Cost Estimating Data Books adjusted to reflect the construction scene in Newfoundland and Labrador.

12. HYDRO Labour and Overhead Costs Relative to Above Items

It is recommended that HYDRO establish a refurbishment project team to organize, award and oversee the work on the Hardwoods items 1 through 11. A preliminary budget cost of 8% of the total capital dollars for these items has been allowed for the labour and expenses of the project team.

13. Miscellaneous Work on Ongoing Operational Issues

Section 4.0 of this Report provided commentary on ongoing operational issues and routine maintenance work carried out at each site over the past 8 years. The Study schedule, budget and scope did not allow the investigation of these sporadic operational issues. It is recommended that HYDRO allocate, as part of the overall refurbishment work budget at each site, an amount of money to thoroughly investigate, engineer and implement solutions to these ongoing sporadic operational issues. It is proposed that a figure of $250,000.00 be allowed for this purpose as part of an overall refurbishment budget.

14. Spare Parts

The spare parts list in Appendix 6 is not comprehensive by any means. A comprehensive review of existing spare parts at the sites was not conducted in the Study. The spare parts list, provided by HYDRO, of currently held spares at the sites was dated 2004 and likely not current. In addition to the spares listed in Appendix 6, it is recommended that HYDRO stock spare cards for each type of card in the DCS System as well as other long term delivery equipment items where a failure of the item could seriously jeopardize the reliability and availability of the Gas Turbine.

7.2.2 Stephenville Gas Turbine Facility Refurbishment Recommendations

Report Section 6.0 provided a condition assessment of the existing equipment and structures at the Stephenville Gas Turbine site. The various refurbishment recommendations contained in Section 6.0 along with associated costs are summarized in a spreadsheet included in Appendix 6. The following is a summary of the costs on an equipment or structure basis.

Table 2
Stephenville GT Facility Refurbishment Costs
(2007 Costs)

Item	Equipment / Structure	Cost (Cdn$)
1	Gas Generator Engines / Power Turbines Equipment	$1,142,520.00
2	Inlet Air Systems A & B	34,700.00
3	Exhaust Stacks A & B	36,900.00
4	Glycol Cooler for Main Lube Oil	10,000.00
5	Gas Generator / Power Turbine Enclosures A & B	18,300.00
6	Fire Detection and Protection	45,000.00
7	Alternator and Excitation System	2,347,000.00
8	Alternator Enclosure	3,600.00
9	Alternator Air Cooling System Glycol Cooler	21,900.00
10	Fuel Oil System	19,750.00
11	Electrical Systems	129,600.00
12	Control & Instrumentation Systems	69,000.00
13	Buildings	74,400.00
15	Miscellaneous HYDRO Work on Ongoing Operational Issues	250,000.00
	Sub-Total:	$4,202,670.00
	HYDRO labour & overhead costs relative to Items 1 – 15 (assume 8% of sub-total)	336,213.00
	Total:	**$4,538,883.00**

Commentary follows on each category of costs:

1. <u>Gas Generator Engines / Power Turbines Equipment</u>

   Refurbishment costs for this category were provided by Robin Sipe of S&S Turbines Services Limited. Mr. Sipe has extensive experience servicing Olympus C engines. The engines would be removed and reinstalled by S&S Turbine's personnel and shipped to Fort St. John BC for refurbishment. Approximately 90 days turn around time would be required to refurbish and test run an engine at the Fort St. John facility. S&S Turbines can provide, at HYDRO's discretion, an engine on a temporary basis to replace the engine shipped to Fort St. John. With a rental engine on site, the engines would be shipped piecemeal such that each site always has 2 engines in service. The costs also include replacing the ignition exciters, the speed governors and fuel valve assemblies. It should be noted that previous refurbishment work on a single engine in 2000 by another service provider was at a substantially higher cost approaching $1.1 million.

   The power turbines will be thoroughly inspected, when an engine has been removed, and refurbished as required. The cost estimate for the power turbine refurbishment anticipates minimal refurbishment work based on observations during the site visits.

The condition of the power turbines will be better known when removed from the enclosures. There could however be additional costs involved following a thorough examination of the power turbines, following the removal of the gas generator engines. There is also a cost included to dismantle and inspect the power turbine clutches.

2. <u>Inlet Air Systems A & B</u>

   These costs include a number of miscellaneous civil refurbishments to the inlet air systems on each end of the Gas Turbines. Refer to Appendix 6 for details. The recommended refurbishments are for structural integrity and safety reasons. The civil cost estimates were derived from the RS Means 2007 Cost Estimating Data Books adjusted to reflect the construction scene in Newfoundland and Labrador.

3. <u>Exhaust Stacks A & B</u>

   These costs include a number of miscellaneous civil refurbishments to the exhaust stacks on each end of the Gas Turbines. Refer to Appendix 6 for details. The recommended refurbishments are for structural integrity and safety reasons. The civil cost estimates were derived from the RS Means 2007 Cost Estimating Data Books adjusted to reflect the construction scene in Newfoundland and Labrador.

4. <u>Glycol Cooler for Main Lube Oil</u>

   The costs cover the refurbishment of the existing glycol cooler including replacement of the bottom section, canopy cladding plus re-coating the entire structure as well as cleaning the tubes in the heat exchanger. The civil cost estimates were derived from the RS Means 2007 Cost Estimating Data Books adjusted to reflect the construction scene in Newfoundland and Labrador.

5. <u>Gas Generator / Power Turbine Enclosures A & B</u>

   The costs cover the removal of corrosion and re-coating the enclosures A & B where required. Also included are modifications to the man doors on each enclosure. The civil cost estimates were derived from the RS Means 2007 Cost Estimating Data Books adjusted to reflect the construction scene in Newfoundland and Labrador.

6. <u>Fire Detection and Protection</u>

   The costs include the supply and installation of an Inergen fire suppression system in the Control Building. Prices were obtained from an Inergen supplier.

7. <u>Alternator and Excitation System</u>

   As discussed in sub-section 6.3.3, due to the absence of electrical testing and visual inspection records on the Alternator over its 30 years of service, it is not possible to determine the present condition of the alternator and exciter and make an assessment of its life expectancy and reliability over the next 15 years. In order to determine the present condition of the alternator and exciter, certain basic electrical tests and visual inspections are necessary. Therefore, the costs in this category include: (i) conducting electrical tests on the stator, rotor and exciter with the alternator in its enclosure (ii) removing the alternator or as a minimum the rotor from its enclosure and carrying out visual inspections and other electrical tests on the stator and the rotor (removed from the stator). The cost estimate assumes major refurbishment work on the alternator and carrying out the necessary refurbishment work at a supplier's shop. The estimate should be considered a worst case upper end cost. Input to the refurbishment estimate was provided by MAN TURBO.

8. <u>Alternator Enclosure</u>

   The costs cover the removal of corrosion and re-coating the enclosures where required. Also included are modifications to the man doors on each enclosure. The civil cost estimates were derived from the RS Means 2007 Cost Estimating Data Books adjusted to reflect the construction scene in Newfoundland and Labrador.

9. <u>Alternator Air Cooling System Glycol Cooler</u>

   The costs cover the refurbishment of the existing glycol cooler including replacement of the canopy cladding plus re-coating the entire structure including the support structure, sealing of joints as well as cleaning the tubes in the heat exchanger. The civil cost estimates were derived from the RS Means 2007 Cost Estimating Data Books adjusted to reflect the construction scene in Newfoundland and Labrador.

10. <u>Fuel Oil System</u>

    These costs include a number of miscellaneous civil refurbishments to the oil storage tank as well as modifications to the containment dyke. Refer to Appendix 6 for details. The recommended refurbishments are for structural integrity and safety reasons. The civil cost estimates were derived from the RS Means 2007 Cost Estimating Data Books adjusted to reflect the construction scene in Newfoundland and Labrador.

11. <u>Electrical Systems</u>

    The Stephenville electrical equipment was generally in good condition and should perform reliably over the next 15 years. Appendix 6 lists a number of refurbishment recommendations and associated costs for HYDRO's consideration. Pricing of the listed equipment was sourced from equipment suppliers.

12. <u>Control and Instrumentation Systems</u>

The ELSAG Bailey INFI 90 DCS system installed in 1999 appears to be working relatively well. While there are currently shortcomings in the existing software/hardware, the storage of data and trending capability, the equipment modifications proposed by HYDRO as outlined in sub-section 6.6.1 should address current problems and improve system capacity and reliability for a further 15 years. In addition, the supplier of this equipment will support the equipment for years to come. Refer to Appendix 6 for further details on other proposed recommendations and costs.

13. <u>Buildings</u>

This category of costs addresses recommendations for refurbishment work on various buildings on the site. Buildings include: (i) Control Building (ii) Fuel Forwarding Building (iii) Parts Storage Building and (iv) Waste Oil Storage Shed. The refurbishments include roofing, cladding and other maintenance work on the Buildings to ensure their structural integrity for a further 15 years. The civil cost estimates were derived from the RS Means 2007 Cost Estimating Data Books adjusted to reflect the construction scene in Newfoundland and Labrador.

This category of costs addresses recommendations for refurbishment work on various buildings on the site. Buildings include: (i) Control Building (ii) Fuel Unloading Building (iii) Fuel Forwarding Building (iv) Auxiliary Module Building (v) Maintenance and Parts Storage Building and (vi) High Voltage Switchgear Building. The refurbishments include roofing, cladding and other maintenance work on the Buildings to ensure their structural integrity for a further 15 years. The civil cost estimates were derived from the RS Means 2007 Cost Estimating Data Books adjusted to reflect the construction scene in Newfoundland and Labrador.

14. <u>HYDRO Labour & Overhead Costs Relative to Above Items</u>

It is recommended that HYDRO establish a refurbishment project team to organize, award and oversee the work on the Stephenville items 1 through 13. A preliminary budget cost of 8% of the total capital dollars for these items has been allowed for the labour and expenses of the project team.

15. <u>Miscellaneous Work on Ongoing Operational Issues</u>

Section 4.0 of this Report provided commentary on ongoing operational issues and routine maintenance work carried out at each site over the past 8 years. The Study schedule, budget and scope did not allow for the investigation of these sporadic operational issues. It is recommended that HYDRO allocate, as part of the overall refurbishment work budget at each site, an amount of money to thoroughly investigate, engineer and implement solutions to these ongoing sporadic operational issues. It is proposed that a figure of $250,000.00 be allowed for this purpose as part of an overall refurbishment budget.

7.3 OPTIONS – REPLACEMENT OF MAJOR COMPONENTS

The major components considered for replacement included the engine, power turbines and alternator. The costs for these replacements are summarized in a spreadsheet included in Appendix 6.

7.3.1 Option 1 – New Gas Generator Engines and Power Turbines

Several equipment suppliers were contacted regarding the replacement of the gas generators and power turbines. MAN TURBO of Europe was the only supplier to provide a qualified cost. MAN TURBO offered two (2) FT8-36 gas turbine engines and power turbines. Each engine/ power turbine is rated at 25 MW. The FT8 aero-derivative machines are Pratt & Whitney machines provided through a cooperation agreement between Pratt & Whitney and MAN TURBO. A copy of the MAN TURBO proposal is included in Appendix 7.

The FT8 engines and power turbines will be supplied complete with auxiliary systems such as lube oil, dryer, fire and CO2 protection, control panel, MCC, etc. It may be possible to utilize existing auxiliary systems however this can only be determined following a detailed review of the existing systems by MAN TURBO. More importantly, excluded from the price provided by MAN TURBO was the air inlet filter assemblies, exhaust stacks, acoustic enclosures or modifications to existing enclosures. It is intended that these structures be reused however any required modifications (and associated costs) to these existing structures would require a detailed review by MAN TURBO. Also excluded from MAN TURBO's scope was any work associated with the existing alternator and SSS clutches, all of which would be re-used following refurbishment (by others) with the new engines and power turbines.

The costs provided by MAN TURBO, converted to present day 2007 Canadian dollars, are as shown in Table 3:

Table 3
Replace Engines and Power Turbines – One Site
MAN TURBO Proposal
(2007 Costs)

Item	Description	Cost (Cdn$)
1	USA Portion of Equipment Supply	$14,100,000.00
2	European Portion of Equipment Supply	6,800,000.00
3	Transportation to Site (Estimate)	200,000.00
4	Erection and Commissioning	2,000,000.00
5	Other refurbishments - average of Table 1 (Hardwoods) and Table 2 (Stephenville)	3,319,761.00
	Sub-Total:	**$26,419,761.00**
6	Modifications to existing engine & power Turbine enclosures and exhaust stacks as required	*To be advised pending further study by supplier*
	Total:	**$**

The costs do not include modifications to the existing air inlet filter assemblies, exhaust stacks and existing enclosures. Further, there potentially could be some cost savings in utilizing some of the existing balance of plant equipment such as lube oil, MCCs etc. Weighed against this would be liability issues if there should be an engine problem arising from the faulty or non-operation of existing balance of plant equipment

The costs in Table 3 apply to one Gas Turbine site only. The figures would double for both sites. Retrofitting the new engines and power turbines at one site would free up the replaced equipment for use at the second site.

In this option, the existing alternator would be retained and refurbished as required. In addition to the costs for new engines and power turbines at either site, all other refurbishment costs (with the exception of the engines/power turbine refurbishment costs) listed in Table 1 (Hardwoods) and Table 2 (Stephenville) would apply to this option. These additional refurbishment costs would be $3,243,160.00 for Hardwoods and $3,396,363.00 for Stephenville. For the purpose of Table 3, an average of the cost at both sites - $3,319,761.00 - is included.

7.3.2 Option 2 – New Alternator/Exciter

It is important to note that the alternators at the Hardwoods and Stephenville sites, while of similar electrical capacity, are different physically. The Stephenville alternator rotor length is 1.64 meters longer than the rotor length at Hardwoods. This difference in length reflects the different cooling systems on each alternator. The Stephenville alternator uses a glycol-water mixture to absorb heat from the air circulating inside the alternator casing and to discharge the heat to ambient air by means of an external heat exchanger complete with fan cooling. The Hardwoods alternator cooling does not use an external heat exchanger. The Hardwoods cooling system consists of intake filters and discharge louvers located on the alternator enclosure.

Brush Electrical Machines Ltd. in Loughborough, England, the supplier of the original alternator/ exciter, was contacted to provide a price for a new replacement alternator/exciter for one of the sites. Brush has pointed out that their alternator design today is different than it was 30 years ago. Modifications to the existing alternator enclosure and bearings arrangement would likely be required in order to retrofit a new alternator.

Brush provided preliminary ballpark information on the costs of a new generator as summarized in Table 4 below. Brush pointed out that the budget estimates are strictly for guidance and do not cover special features that may be required for the project. The estimates do not include line or neutral cubicles or off generator support systems – external radiators, oil services, clutches, etc. Brush notes that there would need to be careful consideration of the major interfaces to make their current machine fit. The big unknown in the preliminary estimate provided by Brush is the cost associated with these interfaces, modifications to the existing enclosure, bearings, etc. Brush is not prepared to invest at this time, the effort required to define the overall scope and costs of retrofitting a new alternator at either site. These costs could be significant and are not known at this time. For the purposes of Table 4, we have provided a rough estimate of $1,000,000 for the modifications required to incorporate a new alternator into the existing infrastructure. The final estimate will have to be provided by Brush following a more detailed study of the existing infrastructure. Refer to Appendix 8 for details on the Brush proposal.

Table 4
New Alternator / Exciter – One Site
(2007 Costs)

Item	Description	Cost (Cdn$)
1	New alternator / exciter	$2,500,000.00
2	Top Mounted standard air filter house	300,000.00
3	Acoustic & weather Protection Canopy	250,000.00
4	Erection & Commissioning (estimate)	750,000.00
5	Transportation (estimate)	75,000.00
6	Interface costs to existing infrastructure & auxiliary systems (estimate)	1,000,000.00
7	Other refurbishments - average of Table 1 (Hardwoods) and Table 2 (Stephenville)	2,288,381.00
	Total:	**$7,163,381.00**

In this option, the existing engines and power turbines would be retained and refurbished. In addition to the costs for a new alternator/exciter at either site, all other refurbishment costs (with the exception of the alternator refurbishment costs) listed in Table 1 (Hardwoods) and Table 2 (Stephenville) would apply to this option. These additional refurbishment costs would be $2,384,880.00 for Hardwoods and $2,191,883.00 for Stephenville. For the purpose of Table 4, an average of the cost at both sites - $2,288,381.00 - is included.

7.4 OPTION 3 – NEW GAS TURBINE

Primarily for cost comparison purposes with the other options considered, several equipment suppliers including Siemens, Alstom and General Electric were contacted regarding the supply of a new 50 MW gas turbine for one or both sites. In spite of repeated requests for costing information, the suppliers were unresponsive to our requests. A new gas turbine would replace the Hardwoods or Stephenville Gas Turbines in their entirety, with the exception of the Fuel unloading/storage infrastructure and step-up transformer/grid interconnection infrastructure at each site. A new gas turbine would include:

- Single aero-derivative engine (similar to General Electric LM6000 Gas Turbine)
- Clutch
- 50 MW alternator c/w synchronous condenser capability
- Mechanical Auxiliary Equipment
  - Fuel Forwarding Module
  - Air Compressor Module
  - Lube Oil System
- Electrical Auxiliary Equipment
  - 13.8 kV Switchgear
  - Motor Control Centre; Battery & Charger; Digital Protection Relays; Bus Duct; Motors; Cabling; etc.
  - Station Service Transformer
- Control & Instrumentation Auxiliary Equipment
  - DCS Control System
  - Vibration Monitoring System
  - Temperature Monitoring System
  - New Instrumentation Devices
- Civil Works
  - Site Preparation
  - Foundations

Based on previous work carried out by Stantec for other clients, we would estimate the cost of a new 50 MW Gas Turbine (similar to the General Electric LM 6000 Gas Turbine) installed at either site to be approximately $30 to $35 million. The existing buildings at Stephenville for example would have to be reviewed to determine their suitability in housing the new mechanical, electrical and controls auxiliary equipment which would be supplied as part of the standard gas turbine package. At Hardwoods, it would be advisable to build a new all purpose building adjacent to the new gas turbine to house all auxiliary equipment.

Table 5
New Gas Turbine – One Site
(2007 Costs)

Item	Description	Cost (Cdn$)
1	New Gas Turbine – Includes supply, erection and commissioning	$35,000,000.00
2	Allowance for HYDRO engineering staff involvement in new gas turbine procurement and installation. (estimate)	400,000.00
	Sub-Total:	**$35,400,000.00**
3	Dismantling of existing Gas Turbine and demolition of buildings as required	1,500,000.00
	Total:	**$36,900,000.00**

The new gas turbine would require a new physical location within the fenced area at either site. The new gas turbine could be installed to a large degree independently of the operation of the existing gas turbine. Following the installation of the new gas turbine, the existing Gas Turbine could be disassembled with the components used as spare parts for the other site. There would be costs involved to dismantle the existing Gas Turbine and remove equipment from the existing buildings. For the purposes of Table 5, we have provided a rough estimate of $1,500,000 for dismantling of the existing Gas Turbine and demolition of surplus buildings and structures.

The installation of a new gas turbine on either site, while the most costly of all options, would have an operational timeframe well beyond 15 years. The installation of a new gas turbine at the Hardwoods site could proceed to the point where connection to the grid and switchover of the fuel supply is required. This would allow the existing Gas Turbine to remain in service for a considerable period while the new gas turbine is being installed.

7.5 TEMPORARY MOBILE GAS TURBINE RENTAL

If the alternator at either Hardwoods or Stephenville requires major refurbishment work at a vendor's shop it could be out of service for a period of 3 to 4 months. If the electrical system cannot tolerate an outage of this duration at either site, the option of using a rental mobile gas turbine(s) was explored. From information provided by HYDRO, the existing machines operate predominantly as synchronous condensers with MVAR loadings typically in the range of 10 to

20 MVAR with peaks up to 25 MVAR. A rental mobile gas turbine rated at approximately 25 MW was sourced. Pratt and Whitney and Caterpillar were contacted on this matter.

Pratt and Whitney

Pratt & Whitney has a mobile 25 MW 13.8 kV gas turbine (“MobilePac”) that could be available as a rental from a third party. Refer to Appendix 9 for information on the Pratt & Whitney MobilePac gas turbine. Pratt & Whitney currently does not have MobilePac units available for rent directly however they are contemplating getting into the leasing/rental business within the next 2 years. Pratt & Whitney has a number of customers who own MobilePac units and have offered to speak to these customers for the rental of one of their units. In particular, Pratt & Whitney has a European customer with 7 MobilePac units that may be available for lease in the summer months. The European customer requires the units for winter peak loads. Pratt & Whitney stated that HYDRO should contact them (Phil Vecchiarelli at 860-565-7877) if there is an interest in pursuing such a rental arrangement. Pratt & Whitney submitted the following preliminary cost estimate ($USA) based on a 4 month rental arrangement. Costs would be firmed up if HYDRO has an interest in the MobilePac gas turbine.

Table 6A
P&W MobilePac Gas Turbine
2007 Preliminary Rental Costs (USA$)

Description	Unit Cost	Total Cost (4 Months)
P & W 25MW GT – 4 Month Rental		
o Transportation to Site		$ 625,000.00
o Site Set up Fee (per site)		150,000.00
o HV Connection		50,000.00
o Fuel Connection		7,500.00
o Monthly rental – 4 months	$400,000.00	1,600,000.00
o Full Time Site Supervisor – 4 months	25,000.00	100,000.00
o Site Dismantle Fee (per site)		150,000.00
o Transportation back to Europe		625,000.00
Total:		**$3,307,500.00**

These costs while in USA$ are equivalent to Cdn$ at the present time. Since Pratt & Whitney are involving a European customer in this potential transaction, Euros$ will likely play a role in any final rental arrangement. The costs in Table 6A apply to one site. If the work at both sites can be accommodated in a single year, there would be a saving on the transportation costs.

Caterpillar

Caterpillar has mobile 5.2 MW, 13.8 kV gas turbines available for rent. For a 25 MW capacity, this would involve 5 Caterpillar machines. Refer to Appendix 9 for information on the Caterpillar machines. The following is a summary of rental costs provided by Caterpillar. The costs are based on 4 months rental duration for one site.

Table 6B
Caterpillar Mobile Gas Turbine
2007 Rental Costs (Cdn$)

Description	Unit Cost	Total Cost (4 Months)
Caterpillar 5 MW GT – 4 Month Rental		
o Rent 5 GT's = 25 MW Capacity		
o Monthly rental (capacity charge) per GT	$105,000.00	$2,100,000.00
o Fired hours charge per GT per hour (Assume 1000 hours for 4 months)	$42.00	42,000.00
o Mobilization & Consumables cost per GT	$16,000.00	80,000.00
o Setup, Commissioning & Testing per GT	$106,000.00	530,000.00
o Decommissioning Costs per GT	$48,500.00	242,500.00
o Full Time Site Supervisor – 4 months	$10,000.00	40,000.00
Caterpillar Sub-Total:		**$3,034,500.00**
o Costs to connect 5 GT's to existing 13.8 kV circuit breaker & step-up transformer (estimate)		50,000.00
o Costs to connect Fuel supply piping (estimate)		7,500.00
Total:		**$3,092,000.00**

The costs in Table 6 are based on 5 gas turbines for 4 months duration. Obviously, if less than 5 machines are required and the alternator refurbishment duration is less than 4 months, the rental costs will be reduced. The costs in Table 6B apply to one site. If 5 rental units for 4 months are required for the second site, the costs will double.

Caterpillar can also provide a technician/operator 12 hours per day and on call for the remainder of the day at a negotiated rate per week.

7.6 OPTION 4 – NEW DYNAMIC VAR COMPENSATOR

The HYDRO RFP scope focused on what should be done to ensure the reliable operation of the Hardwoods and Stephenville Gas Turbines for a further 15 years of service. While the concept of replacing one or both of the Gas Turbines with another technology for MVAR support of system voltage is beyond the scope of this Study, we are presenting the concept of dynamic var compensation for HYDRO's consideration only.

The Gas Turbines at both the Hardwoods and Stephenville sites operate primarily as synchronous condensers providing system voltage support on the eastern and western regions of Newfoundland. From information provided by HYDRO, the Gas Turbines at each site operate as synchronous condensers in excess of 90% of the running hours of the alternator. An option for HYDRO to consider would be the replacement of either one or both Gas Turbines with dynamic var compensators for system voltage support.

Since Hardwoods has many more operational hours than does Stephenville, the option presented in this Report for HYDRO's consideration is the replacement of the Hardwoods Gas Turbine with dynamic var compensation and retention of the Stephenville Gas Turbine. With the Holyrood Generating Station located in the eastern portion of Newfoundland, there is significant existing generation in the region served by Hardwoods. Components from the retired Hardwoods Gas Turbine can then be used as spare parts for the Stephenville Gas Turbine. In addition, elimination of the Hardwoods Gas Turbine would result in operational and maintenance savings.

American Superconductor Corporation of Wisconsin has developed a Dynamic VAR Compensation system that dynamically stabilizes and regulates voltage on transmission grids and industrial operations. The system denoted as D-VAR detects and instantaneously compensates for voltage disturbances by injecting leading or lagging reactive power at points of interconnection on the transmission or distribution grid. The variable output of the D-VAR device is typically the first source used to regulate voltage. As additional compensation is required, the D-VAR system will switch a capacitor bank (or reactor) in or out. At the exact moment of switching, the D-VAR device instantaneously injects (or absorbs) the same amount of VAR's as the capacitor bank, eliminating the step voltage change that would otherwise occur. The D-VAR system then resumes its normal voltage regulation mode, dynamically injecting or absorbing VAR's as required. Information provided by HYDRO on MVAR loadings at the Hardwoods site illustrates that the MVAR loadings at that site rarely exceed 25 MVAR with most loadings in the 10 – 20 MVAR range. D-VAR systems are flexible and scalable ranging from 2 MVAR to hundreds of MVAR.

The application of a D-VAR system at the Hardwoods site however would require an in-depth study with involvement by the D-VAR supplier. A system study would likely be involved to determine the size, configuration, terminal station interconnection requirements, operational requirements and costs of the D-VAR system. Such a study is beyond the scope of this Study.

This Study has not sourced capital costs associated with the supply and installation of a D-VAR system at the Hardwoods site for the reasons noted above. It is our opinion however that the costs associated with this option would be competitive with the other options outlined herein. A ballpark estimate for a D-VAR system at Hardwoods would likely be in the range of $5-10 million. Stantec would be willing to undertake a more detailed study on this technologies potential application at HYDRO's discretion. Again, the application of D-VAR technology at Hardwoods is introduced solely for HYDRO's consideration. While some information on D-VAR technology, obtained from the Web, is included in Appendix 10, discussions with the D-VAR supplier are mandatory to obtain more detailed information on the potential application of this technology at Hardwoods.

Following the installation of the D-VAR system, the existing Gas Turbine could be retained with minor refurbishments for standby power generation purposes or disassembled with the components used as spare parts for the other site. There would be costs involved to dismantle the existing Gas Turbine, buildings, fuel storage tank and other infrastructure. These costs would be in addition to the figures presented in the preceding paragraph.

8.0 LIFE CYCLE COST ANALYSIS OF REFURBISHMENT OPTIONS

8.1 GENERAL

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

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

8.2 FINANCIAL MODEL INPUT DATA/CRITERIA/COSTS

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

8.2.1 MWHRS AND MVAR OUTPUT

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

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

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

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

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

8.2.2 Operations and Maintenance Budgets

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

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

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

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

8.2.3 Gas Turbine #2 Oil Fuel Price Forecast

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

Table 8
 # 2 Oil Fuel Price Forecast (Cdn$/l)
2008 - 2023

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

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

8.2.4 Inflation and Escalation Forecast

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

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

8.2.5 Fuel Consumption at Each Site

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

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

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

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

8.3 SUMMARY OF GAS TURBINE FACILITY REFURBISHMENT CAPITAL COSTS

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

Table 10
Gas Turbine Facility Refurbishment Capital Costs
(2007 Costs)

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

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

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

8.4 LIFE CYCLE COST ANALYSIS ASSUMPTIONS AND COMMENTARY

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

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

Initial project capital cost is incurred end of year 2008

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

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

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

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

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

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

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

For Sub-Case #1, it is assumed that a complete refurbishment of the unit will again be required in 2023 at identical refurbishment costs as incurred in 2008 escalated forward to 2023. For

Sub-Case #2, an allowance is made for complete replacement of the unit in 2023 with a new gas turbine. Future costs are escalated using the default value in the NLH model. Resulting replacement costs in 2023 dollars are $11.8 million and $55.6 million for Sub-Cases #1 and #2, respectively.

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

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

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

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

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

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

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

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

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

For Sub-Case #1, it is assumed that a complete refurbishment of the unit will again be required in 2023 at identical refurbishment costs as incurred in 2008 escalated forward to 2023. For

Sub-Case #2, an allowance is made for complete replacement of the unit in 2023 with a new gas turbine. Future costs are escalated using the default value in the NLH model. Resulting replacement costs in 2023 dollars are $11.8 million and $55.6 million for Sub-Cases #1 and #2, respectively.

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

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

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

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

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

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

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

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

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

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

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

8.4.6 Option No. 2 – Replacement of Alternator and Exciter

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

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

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

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

8.4.7 Option No. 3 - New Gas Turbine Facility

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

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

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

8.4.8 Option No. 4 - Dynamic Var Compensation

Although this option requires additional investigation, a scenario was developed to gauge the potential of dynamic VAR compensation. No allowance is included for rental equipment, as it is assumed that the new equipment would be installed while the old system was still operational.

For future annual costs, it is assumed that fuel consumption will be eliminated and O&M costs will be reduced to 10% of historical.

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

8.5 LIFE CYCLE COST ANALYSIS RESULTS AND RANKING OF OPTIONS

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

Table 11
CPW of Alternatives

Ranking	Option	CPW (2007 Cdn$)	
		Sub-Case #1	Sub-Case #2
1	Option 4 – DVAR	$8,995,597	$8,995,597
2	Base Case 2B- Stephenville Refurbishment, No Rental Allowance	$9,548,569	$24,996,028
3	Base Case 1B- Hardwoods Refurbishment, No Rental Allowance	$11,467,914	$26,930,650
4	Base Case 2A- Stephenville Refurbishment with Rental Allowance	$13,842,768	$27,711,405
5	Base Case 1A- Hardwoods Refurbishment with Rental Allowance	$16,010,747	$29,894,660

Ranking	**Option**	**CPW (2007 Cdn$)**	
		Sub-Case #1	**Sub-Case #2**
6	Option 2 – New Alternator/Refurbish Engines & Turbines	$16,248,954	$28,574,070
7	Option 1 – New Engines/Refurbish Alternator	$33,088,681	$36,221,835
8	Option 3 – Complete New GT Unit	$38,145,919	$38,145,919

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

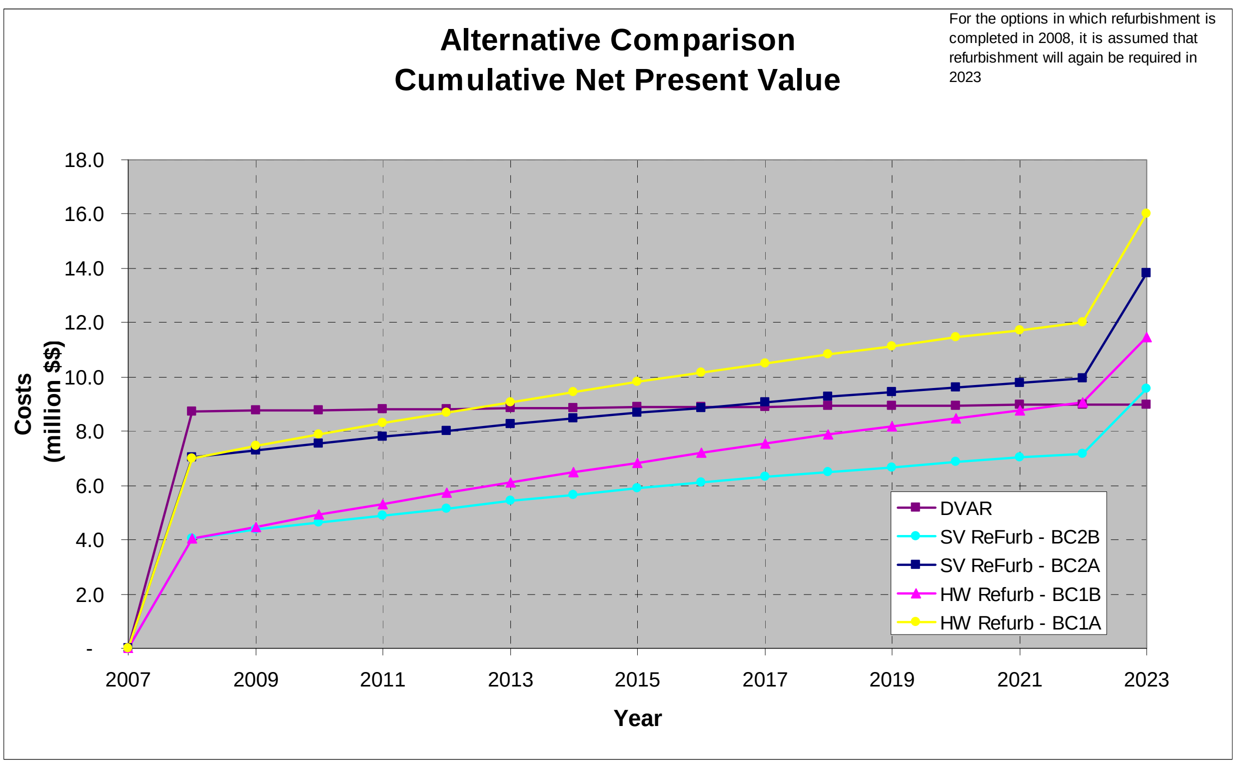

Figure 1
Sub-Case #1 – Base Cases and DVAR Compensation

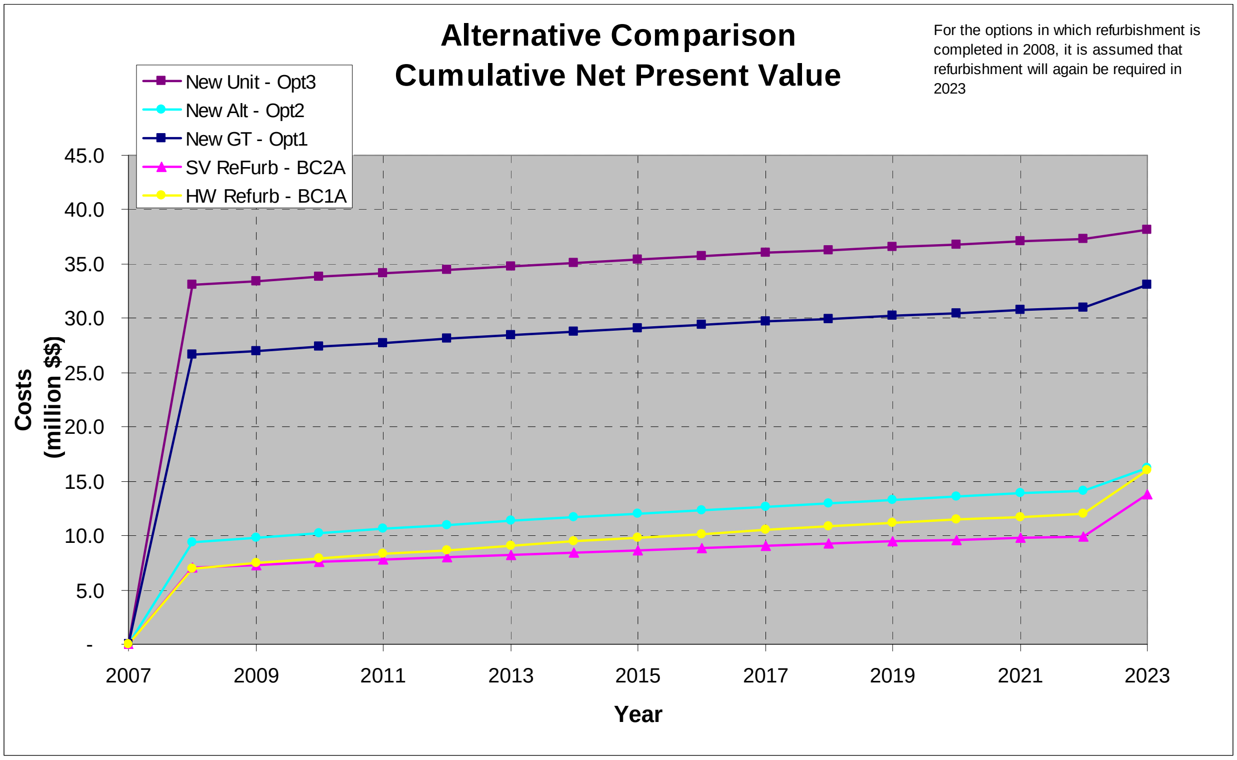

Figure 2
Sub-Case #1 – Base Cases and Equipment Replacement Options

9.0 CONCLUSIONS AND RECOMMENDATIONS

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

The Study assessed the condition of equipment and structures at each site, Report Sections 5 and 6, and evaluated a number of potential options, Report Section 7, to achieve HYDRO's objective. The 15-year life cycle cost analysis and ranking of each option is summarized in Table 11 of Report Section 8. The Table is repeated here for convenience.

Table 11
CPW of Alternatives

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

Option 4

While Option 4, the D-VAR addition at one site, has the No. 1 ranking in the options considered primarily due to significantly reduced operations and maintenance costs going forward, the capital costs used in the life cycle cost analysis are at best ballpark estimates and can only be confirmed through a detailed study on the application of this technology at one or both sites. The question that HYDRO must address regarding this Option involves whether backup emergency generating capability is absolutely required at either site.

- ***Recommendation:*** *If the answer to the above question is yes, then dismiss this Option from further consideration. If the answer to the above question is no, then proceed with a more detailed study of this Option with the involvement of the equipment supplier to confirm costs and technical details. It is Stantec's opinion that this Option would be competitive with the Base Case existing equipment refurbishment Options for MVAR system voltage support only should HYDRO decide to forego generation capability at either site.*

Base Case Options: 1A – 1B – 2A – 2B

The Base Case options of refurbishing the existing equipment including the gas generator engines, power turbines and alternator are ranked as follows:

- No. 2 Ranking – Stephenville refurbishment (Case 2B) with no allowance for a temporary mobile gas turbine rental. It is estimated that a 4 month outage would be required for an alternator major off-site refurbishment.
- No. 3 Ranking -- Hardwoods refurbishment (Case 1B) with no allowance for a temporary mobile gas turbine rental. It is estimated that a 4 month outage would be required for an alternator major off-site refurbishment.
- No. 4 Ranking – Stephenville refurbishment (Case 2A) with an allowance for an estimated 4 month mobile gas turbine rental to cover the outage period.
- No. 5 Ranking – Hardwoods refurbishment (Case 1A) with an allowance for an estimated 4 month mobile gas turbine rental to cover the outage period.

The Stantec team is of the opinion that the existing equipment, particularly the gas generator engines, power turbines and alternator, as well as the balance-of-plant equipment and structures can be refurbished sufficiently to allow reliable operation over the next 15 years. If HYDRO selects the Base Case refurbishment options, HYDRO will have to make a decision on whether to pursue a temporary mobile gas turbine rental arrangement with equipment suppliers or tolerate an estimated 4-month outage at each site. The rental costs used in the analysis are strictly budget figures provided by two equipment suppliers. Final rental costs could be more or less.

The existing balance-of-plant systems and equipment at each site are generally in good condition. This includes the mechanical fuel unloading and forwarding equipment; electrical equipment – transformer; switchgear; motor control; batteries; etc; control and instrumentation equipment – Bailey DCS equipment; instrumentation devices; etc. As discussed in Report Sections 4, 5 and 6, there is some degree of minimal refurbishment work required in these systems. Refurbishment recommendations are outlined in Report Appendix 6.

Since no information was available to assess the condition of the alternator, the decision on the extent of refurbishment work required on this equipment will not be known until a thorough electrical testing and visual inspection of the stator and rotor is conducted. At that time, HYDRO will have to make a decision as to whether refurbishment or replacement is required. A new alternator was assessed under Option 2.

- ***Recommendation:*** *The Base Case existing equipment refurbishment option at each site has the lowest CPW of the Options and is the recommended approach for HYDRO to pursue in order to provide a further 15 years of reliable service. The major unknown is the current condition of the alternator and whether it needs refurbishment or replacement in order to provide reliable service for a further 15 years. If replacement is required, then Option 2 should be pursued.*

Option 2

Option 2, involving the procurement of a new alternator coupled with the refurbishment of the existing gas generator engines and power turbines, as well as other balance-of-plant equipment and structures has a No. 6 Ranking of the refurbishment options considered. While this Option could reduce the outage time that would apply to refurbishing the existing alternator off-site, a 4-month allowance for a rental gas turbine is included in this Option. Again, HYDRO would have to decide if the rental unit is required or an estimated 4 month outage at each site can be tolerated. This Option would involve major modifications to the existing alternator enclosure as well as tie-ins to existing auxiliary systems to accommodate the current design of alternator. While a ballpark estimate has been provided for these costs, the costs would have to be finalized following a more detailed investigation of the enclosure and other interfaces by the alternator supplier. This Option would provide a new alternator with a life span greater than 15 years.

- ***Recommendation:*** *As discussed above, this Option would likely only be pursued, if following a thorough electrical testing and visual inspection of the existing stator and rotor (rotor removed from stator), it is determined that alternator replacement is a better option than refurbishment to allow reliable operation for a further 15 years. Further review by the equipment supplier is required to confirm the final alternator costs.*

Option 1

Option 1, the procurement of new gas generator engines and power turbines coupled with the refurbishment of the existing alternator, as well as other balance-of-plant equipment and structures has a No. 7 Ranking of the refurbishment options considered. Since the alternator is refurbished off-site in this Option, a 4 month allowance for a rental gas turbine is included in this Option. Again, HYDRO would have to decide if the rental unit is required or a 4-month outage at each site can be tolerated. This Option would involve modifications to the existing engines and power turbine enclosures to accommodate the design of new engines and power turbines proposed. These costs are not included and would follow a more detailed investigation of the enclosure by the equipment supplier. This Option would provide new engines and power turbines with a life span greater than 15 years.

- ***Recommendation:*** *This Option should not be pursued due to its high CPW value as well as unknown additional costs to incorporate the engines and power turbines in the existing enclosures and connection to the alternator.*

Option 3

Option 3, a complete new gas turbine, has a No. 8 Ranking of the refurbishment options considered. This Option would have the least impact on operations at either site as outage time to connect the gas turbine to the electrical grid via the existing 13.8/66 kV transformer would be minimal. An estimate is provided for demolition costs associated with removal of the gas turbine replaced by the new unit. This Option would provide a gas turbine with a 30 year life span with lower O&M costs.

- ***Recommendation:*** *This Option should not be pursued due to its high CPW value and the fact the existing equipment can be refurbished to provide reliable service for the 15 year period specified by HYDRO.*

A decision on the role of the Hardwoods and Stephenville Gas Turbines in the HYDRO system beyond 2023, the specified 15 years of further service, has not been determined by HYDRO at this time. The financial analysis results in Table 11 reflect two scenarios beyond 2023. The first scenario (sub-case 1) assumes further refurbishment work in 2023, whereas the second scenario (sub-case 2) assumes the equipment will be replaced in 2023 with new. The two scenarios do not affect the overall ranking of the Options.

10.0 CLOSURE

This Report was prepared for the sole benefit of Newfoundland and Labrador Hydro. The Report may not be used by any other person or entity without the express written consent of Stantec Consulting Ltd ("Stantec") and Newfoundland and Labrador Hydro.

Any use which a third party makes of this Report or any reliance on decisions made based on it, are the responsibility of such third parties. Stantec accepts no responsibility for damages, if any, suffered by any third party as a result of decisions made or actions taken based on this Report.

The information and conclusions contained in this Report are based upon work undertaken by trained professional and technical staff in accordance with generally accepted engineering practices current at the time the work was performed. Any site-specific information and documentation provided by other parties and used or referenced by Stantec has been assumed by Stantec to be accurate. Conclusions presented in this Report should not be construed as legal advice.

This condition assessment and life cycle cost analysis study was undertaken exclusively for the purpose outlined herein. This work was specific to the Hardwoods and Stephenville sites. The Report cannot be used or applied under any circumstances to another location.

ENGINEERING CONDITION ASSESSMENT AND LIFE CYCLE COST ANALYSIS

HARDWOODS & STEPHENVILLE GAS TURBINE FACILITIES

APPENDICES

APPENDIX 1
MINUTES OF STUDY KICK-OFF MEETINGS
HARDWOODS AND STEPHENVILLE

APPENDIX 1
MINUTES OF STUDY KICK-OFF MEETINGS
HARDWOODS AND STEPHENVILLE

Project Team - Stephenville and Hardwoods Condition Assessment
July 26, 2007

Name	Title	Phone	E-mail
HYDRO			
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NOTES OF MEETING

Kick-off Meeting
Hardwoods & Stephenville Gas Turbines Condition Assessment

Date: 2007-07-17/18
Location: NLH Office Stephenville, NL

Present: **For Newfoundland and Labrador Hydro**

Name	Position	Initials
Nelson Seymour	Mgr Mechanical Eng.	NS
Jim Wheeler	Asset Specialist	JW
Ray Rowe	GT Operator	RW
Stephen Carter	Production Super	SC
Len Patey	Mech. Maintenance	LP
Bob Woodman	Maintenance Project	BW
Dave Hicks	Electrical Eng.	DH

For Neill and Gunter (Nova Scotia) Limited

Name	Position	Initials
Brian King	Lead Mech. Eng	BK
Mark Reynolds	Civil Eng.	MR
Alan Wong	Electrical Eng.	AW
Jean Marc St. Pierre	C&I Eng.	JMS
Robin Sipe (S&S Turbine Services)	Turbine Specialist	RS
Bill Hearn	Project Manager	BH

Purpose: **Kick-off Meeting – Gas Turbines Condition Assessment**

Day 1 – July 17, 2007

Action By

1. **Introductions**

Introductions were made. NS pointed out that NLH's Craig Warren (Controls) and Tony Chislett (Civil – structural & oil tanks) were not able to attend the Meeting due to other commitments; however both could be contacted via telephone at a later date. NS also noted that Frank Ricketts (St. John's) could be contacted on GT Environmental issues as well as Operating Permit criteria.

While the Meeting focused on the Stephenville Gas Turbine (GT), there were numerous references to the sister GT at the Hardwoods site in St. John's. NS noted that Engine/Power Turbine B was currently on Outage and available for Inspection later in the day. Engine/Power Turbine A would be available for Inspection on July 18.

ACTION 2. **<u>General Discussion</u>**

General discussion on the Study scope and GT issues ensued. Major issues noted by NLH included:

- Reliability – Remote starts on an as required basis are not always successful. More success if preparatory work done prior to start as per local manual starts. A random list of sporadic problems contribute to many of the unsuccessful starts – fuel supply; vibration problems; clutch problems (possibly proximity switch, valve or controls rather than mechanical issues); anti-icing valve issues. (Prior to the Meeting NLH had provided a multi-page email outlining typical start-up problems experienced at each Site over the past 1.5 years). Some of these problems may be an issue on one start up and not on the next.

- Anti-Icing Issue – There appears to be some uncertainty as to whether the anti-icing device has ever operated, as well as uncertainty on the control mechanism to operate the valve. Is there a detection system to operate the valve? RS will check to see if probes are there. RS noted that when the anti-icing valve is in operation, the GT thermal efficiency could be reduced as much as 1-1.5%. It may be necessary to replace the anti-icing system.

- A new Bailey Control System was installed at each Site in 1997 to replace the original GT control system. Noted there was little data storage and trending capability in the Bailey System; OEM support service was not good; logic changes have been made by NLH over the ensuing years. Number of monitoring points for remote operation from the ECC in St. John's is limited.

- There are issues with the vibration & temperature monitoring systems; availability of spare parts; etc.

- Glycol Cooling Issues – (i) Presently the Glycol Cooler associated with Generator cooling system is out of service. A Generator high temperature alarm prompted the action. The Glycol Cooler will be out of service until the problem is resolved. In the interim, outside air (sometimes moist, possibly salty) is admitted through the Generator access

ACTION

doors. (It was noted that the Hardwoods GT uses air directly for cooling purposes); (ii) The Glycol Coolers for Generator and lube oil cooling are showing signs of corrosion. In fact the Lube Oil Glycol Cooler corrosion is well advanced and in need of immediate short term repair. (It was noted that the bottom pads of the lube oil Glycol Cooler at Hardwoods had been replaced) and (iii) The condition of the buried piping between the Glycol Coolers and the GT is unknown at this time.

- Exhaust stacks – The Stephenville stacks were replaced in 1992. (i) There are known cracks in one and possibly both stacks; (ii) Stack access, particularly around the snow doors, was identified as an issue – need for additional ladders and platforms. (It was noted that the original stacks are in place at Hardwoods); (iii) there have been issues with the pistons on the snow doors at Stephenville not allowing the snow doors to open; (iv)The access hatches to the Exhaust stacks were noted by NLH to be very small as well as bolted shut. This design results in an Area Classification of "confined space". NLH would like to see hinged access doors instead so that they can enter without resorting to extensive safety requirements.

- Air intake structures should have screens.

- GT enclosure door windows -- Viewing windows in a number of enclosure doors was identified as an issue of not being able to identify if there is a fire or safety problem prior to gaining access.

- The exhaust stack silencers appear to be performing well.

NG

- Fuel Forwarding Building – (i) the floor is approximately 3 feet below grade. There is a question of whether this area should be considered as a "confined space area". The GT uses #2 Diesel Oil. NG will investigate the following codes and provide an opinion:
    - API 500 – Division Classifications
    - API 505 – Zone Classifications
    - NEPA 497 – Class 1 Hazardous Locations Classification

  (ii) An issue with the metering on the Fuel Forwarding skid was noted.

- The buried fuel oil supply piping between the Fuel

ACTION

Forwarding Building and the GT is planned to be replaced this year. The piping will be placed in a trench in accordance with current Environmental Protection Codes.

- NLH is of the opinion there may be a problem with the regulating valve on the fuel inlet to the Engines.
- An Inergen fire suppression system has been installed at various locations on the Site – Generator / Engine / Fuel Forwarding Building. There however is no such system installed in the Control Building Electrical Equipment Room.
- It was stated by NLH that corrosion was found on the lube oil coolers in the machine. RS noted that when a peaking GT does not run long enough to boil off any moisture/water in the lube oil system (say less than 2 hours), there can be corrosion problems in the bearings as well.
- Wiring termination boxes -- NLH noted there is corrosion in a number of terminal boxes around the GT enclosures. RS noted that JB's should not be mounted directly on the Engine – can be impacted by vibration.
- Engine wash system – NLH noted that this system was rarely (perhaps never) used for years. RS noted that washing on line was not effective and suggested that an off-line wask/soak at low rpm was the best approach.
- A new enclosue had been placed over the Generator output bus duct as a result of a phase to phase flashover problem experienced in the past.

NLH

- GT spare parts are mainly located at the Hardwoods Site. BK asked if there was an inventory list? If yes, NLH was requested to provide a copy of the list.
- The Generator AVR at Hardwoods was replaced last year. There is currently a budget item (subject to approval) to do the same at Stephenville in the near future.
- Safety issues – NLH stated there should be (i) a railing on top of the Generator enclosure as the protective coating can be slippery at times; (ii) a platform under the door to the Generator heat exchanger as well as a viewing window in that door.

ACTION **3.** **Documentation**

NLH

WH tabled a Documentation List (copy attached) listing reports, drawings and other documentation that NG would like NLH to provide as part of the Condition Assessment Study. The NG List applies to both Gas Turbine Sites. NS also tabled a list of NLH documentation available at this time (copy attached). Also attached is a list of drawings and other documentation that NG currently has at its Dartmouth office. The three items listed are in Appendix 1 – Documentation Lists.

4. **NG Audit Check List**

WH tabled for information an NG Audit Check List that would be the basis of the Condition Assessment Study. A copy of the List is attached as Appendix 2. There was no discussion on the List.

NLH

On an operational issue, NG will need to know the pattern of use that is made of the two Gas Turbines in terms of the annual number of start/stop cycles and for what purpose – synchronous condenser or MWh production.

5. **Costing Information**

NLH

As part of the life cycle cost analysis portion of the Study, BK asked that NLH make available their cost data for operation & maintenance for each of the 50 MW GT Plants on an annual basis. BK also asked if NLH had researched and called for pricing on the replacement of one of the 50 MW GT Plants.

6. **Slides Presentation**

JW provided commentary on a Slide presentation of pictures taken at the Stephenville Site. NLH provided a CD of the photos to NG.

7. **Site Visit**

NG visited the Stephenville Site in the afternoon in the company of the NLH personnel. Engine/Power Turbine B and the Generator were available for inspection, as well as the various auxiliary systems. RS conducted a borescope inspection of Engine B. Following the inspection, Engine/Power Turbine B and the Generator were run up to speed and synchronized to the grid. The startup was successful. A vibration alarm on the exciter was observed. The Generator was loaded to approximately 5 MW for demonstration purposes. The intent was to place the Generator in synchronous condenser mode for the balance of the day. Two observations were noted: (i) the exhaust from stack B on startup was quite dirty indicated unburned hydrocarbons and (ii) the vibrations in the ground around the B side of the Gas Turbine were quite pronounced. This raised the question of when the shaft alignment was last checked and that it should be done again.

Workmen were active on repairs to the lube oil glycol coolers support structure. It was observed that the fins on both glycol coolers appeared to be coated with a grey dust that would likely impair heat conduction. The suggestion was made that some sort of cleaning should be implemented such as steam or chemical washing (HVAC Condenser Cleaning specialists would be a logical area to explore).

Prior to cleaning, it would be useful to collect some temperature data on glycol in/out; air in/out and lube oil in/out when the systems are in operation before and after cleaning. If some temporary system for glycol flow measurement could be installed, this would provide very useful data for future testing.

It was noted there is only one glycol circulating pump for the main lube oil system. There ought to be a replacement pump in NLH spares inventory as a backup to both Sites.

NG mechanical, electrical, Controls and civil personnel toured the Site making observations of the condition of the Gas Turbine and the auxiliary systems.

Day 2 – July 18, 2007

8. Documentation

NLH

The NG Documentation List was extensively reviewed. NLH will assign personnel to locate and provide the documentation currently outstanding. It was agreed that a target date for assembling this information (both Sites) will be August 15, 2007. The information will be provided to NG in advance of the visit to the Hardwoods Site, tentatively planned for w/o August 20th.

9. Site Visit

NG's MR spent the morning on the Site to review/inspect Civil items not looked at on Day 1. Other NG personnel spent the morning at the NLH office discussing documentation as noted in

Item 8.

All NG personnel visited the Site in the afternoon. Engine/Power Turbine A was available for inspection. NG decided to have RS remain at Site in the afternoon to carry out borescope and other inspections on Engine/Power Turbine A. NG further decided, with the exception of RS, to cut short the intended 3 day visit to Stephenville for several reasons: (i) NLH had agreed at the morning Meeting to locate the outstanding documentation (Item 8) and have it available for August 15th – (the NG proposal was based on NLH providing the requested documentation in advance of the Kick-off Meeting); (ii) the 3 days was a guesstimate of time required on the Site – (the NG proposal was based on one full day visit per Site) and (iii) NG personnel were of the opinion they had inspected the equipment, with the exception of Engine/Power Turbine A, sufficiently and it would not be cost effective for NLH to have all NG personnel remain on Site for an additional day.

On Day 2, the Generator was running in synchronous condenser mode absorbing 19 MVAR.

Minutes Prepared By:
Bill Hearn

APPENDIX 1
DOCUMENTATION LISTS

NG

Neill and Gunter

DESIGN AND CONSULTING ENGINEERS

FINAL -----

2007-07-13 --------- Rev 2

GAS TURBINE CONDITION ASSESSMENT DOCUMENTATION LIST

General

1.1 Gas Turbine Facility Maintenance Records (all equipment)
1.2 Gas Turbine Facility Operational Logs
- Forced Outage Information

1.3 Gas Turbine Facility Major Overhaul Reports (all equipment)
1.4 Inspection Reports (all equipment over past 10 years)
1.5 Test Reports (all equipment over past 10 years)
1.6 Site Layout Drawing
1.7 Other

Mechanical

2.1. Gas Turbine

2.1.1 Gas Turbine Drawings and O&M Manuals on:
- Gas Turbine Equipment – engine; power turbine
- Fuel Forwarding Module
- Control Module
- Air Intake Structure
- Exhaust Stacks

2.1.2 Gas Turbine Boroscope Inspection Reports
2.1.3 Maintenance Scheduling Planned
2.1.4 List of major Gas Turbine Spare Parts at Site
2.1.5 List of existing parts/service providers for gas turbine equipment
2.1.6 Oil Analysis Reports
2.1.7 Other

2.2 Mechanical Auxiliary Systems

2.2.1 Drawings and O&M Manuals on:

- Fuel Oil Unloading Equipment
- Fuel Oil Storage Tank(s) and Piping System
  - Records of Internal & External Inspections
  - Inspection Checklists
  - NDT Examinations
  - Piping System
    - Original Design Information
    - Record of any Upgrades
    - History of Leaks/Spills
- Compressed Air Equipment
- Glycol Equipment
- Lube Oil Equipment

2.2.2 Other

Electrical

3.1 Before Site Meeting (if possible)

3.1.1 Electrical Single Line Diagram
3.1.2 Protection and Control Single Line Diagram

3.2 During and After the Meeting

3.2.1 O&M Manuals & Drawings for:

- Generator
- Excitation System
- Generator Output Bus Duct
- Switchgear and Breaker
- Motor Control Centre
- Motors
- AC Distribution System (Station Service and Transfer Switch)
- DC Distribution System (Battery and Charger)
- Relays (relay spec sheets)

3.2.2. Test Reports on tests carried out on the equipment listed in Section 3.2.1.
3.2.3 Maintenance Records on equipment listed in Section 3.2.1
3.2.4 Equipment Addition and Replacement Records
3.2.5 Protection and Control Tripping Logic Diagram

3.2.6 Equipment and Grounding Layout
3.2.7 List of major equipment spares at Site
3.2.8 List of existing parts/service providers for power equipment
3.2.9 Other

Instrumentation & Control

4.1 Before Site Meeting (if possible)

4.1.1 Control System Architecture including communication links
4.1.2 Equipment layout drawing with control panels and equipment identified
4.1.3 P&ID's

4.2 During and After the Meeting

4.2.1 List of component model and part numbers for each control system -Controllers, I/O cards, communication cards, power supplies, FTA's
4.2.2 Programming software and platforms per control system
4.2.3 I/O type and count per system
4.2.4 List of Field Instrumentation devices (flow switches, pressure switches, etc) c/w supplier and service information
4.2.5 SCADA system information
4.2.6 List of known problems and proposed remediation
4.2.7 Control system maintenance records c/w control component replacement frequencies
4.2.8 List of control system spares at Site
4.2.9 List of existing parts/service providers for control equipment
4.2.10 Other

Civil

•

July 17th/07

NLH Documentation:

	Format
(1) Hardwoods Gas Turbine Control System — - Elsag Bailey - - 1997	Binder
(2) Hardwoods Gas Turbine In House Training — - Owner: Howard Richards (NLH - P&C)	Binder
(3) Combustion Turbine Control System Description - Provided by Craig Warren (NLH - P&C) - Four 8½x11 pages plus 6 drwgs.	
(4) Hardwoods & Stephenville Gas Turbine — Work Order Historys.	Binder
(5) Stephenville Drawings — - Total of 15 (Mech. & Civil)	Drwgs
(6) Stephenville G/T Plant Manual — - Produced by FERN Engineering - Owner; Alberta Marche (NLH - Mech.)	Binder
7) Stephenville Plant O&M Manuals — - As originally provided by Curtis Wright	Several Binders & also in electronic format
(8) Gas Turbine Plant Inspection Sheets	
- Daily	- Paper copy
- Weekly	- "
- Semi Annually	- "
- Annual	- "
- 5 yr Inspection	- "
- P&C Six Year	- "
- Gas Turbine Test Run	- "
- Metal Clad Switchgear	- "
9) Boroscope Report - Svl & Hwds G/T's — - Produced by Alba Power - June/07	electronic

Revision 0 --- July 24, 2007

STEPHENVILLE GAS TURBINE SITE
DRAWINGS / DOCUMENTATION PROVIDED BY NLH

1. DRAWINGS

Drawing No.	Title
B1-319-C-64	SGT - Tank Farm Site Layout
B1-319-C-65	SGT - Tank Farm Miscellaneous Sections & Details
F-319-C-29	SGT - Tank Farm External Piping Support Details
3965-E-319-M-7	SGT - Tank Farm Piping Arrangement
F-319-C-24	SGT - Fuel Pumphouse Foundation & Details
3965-E-319-M-6	SGT - Fuel Pumphouse Piping, Plan & Sections
3965-E-319-M-5	SGT - Fuel Oil System Flow Diagram
F-319-M-2	SGT - Fuel Oil System Profile & Location Plan
B1-319-M-13	SGT - Glycol Cooler Structural Details & Water Drain
A1-319-M-014	SGT - Standby Diesel Building & DG Installation
F-319-C-52	SGT - Building Alterations & Miscellaneous Details
A0 - 319-C-47	SGT - Foundation Layout
D-319-C-31	SGT - Sump Layout & Details
A2-319-M-11	SGT - Caged Ladder and Catwalk Assembly on Exhaust Stacks
A2-319-M-12	SGT - Caged Ladder & Catwalk Details
B1-374-E-007	SGT - Transducers, Speed Repeaters Aand Misc. Panel Services Schematic
B1-374-E-008	SGT - Vibration Monitoring Equipment Wiring Diagram
B1-374-E-010	SGT - Generator-Transformer Metering And Protection
B1-374-E-011	SGT - Voltage Regulator Schematic
B1-374-E-027	SGT - DCS Topology
B1-374-E-028	SGT - DCS Racks Layout

2. DOCUMENTS

1	Curtis Wright Hardwoods GasTurbine Manual (provided on CD)
2	Alba Boroscope Report on Engines at Hardwoods & Stephenville
3	Photos of Stephenville Gas Turbine (provided on CD)
4	Stephenville GT Station Log Extractions --- 1992 - 2006
5	Stephenville GT Station Work Order Extractions --- 1999 - 2006

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NOTES OF MEETING

Kick-off Meeting
Hardwoods Gas Turbine Condition Assessment

Date: August 21, 2007
Location: HYDRO Office, St. John's

Present: **For Newfoundland and Labrador Hydro**

Name	Position	Initials
Nelson Seymour	Mgr Mechanical Eng.	NS
Jim Wheeler	Asset Specialist	JW
Andrea MacDonald	Mechanical Eng.	AM
Greg Read	Mechanical Eng	GR
Stephen Carter	Production Super	SC
Tony Chislett	Civil Engineer	TC
Bob Woodman	P&C Engineer	BW
Amanda O'Brien-Pilgrim	Electrical Eng.	AOP
Kevin King	Electrical Engineer	KK
For Neill and Gunter (Nova Scotia) Limited		
Brian King	Lead Mech. Eng	BK
Mark Reynolds	Civil Eng.	MR
Alan Wong	Electrical Eng.	AW
Jean Marc St. Pierre	C&I Eng.	JMSP
Robin Sipe (S&S Turbine Services)	Turbine Specialist	RS
Bill Hearn	Project Manager	BH

Purpose: **Kick-off Meeting – Gas Turbines Condition Assessment**

Day 1 am – August 21, 2007

Action By

1. **Introductions**

Introductions were made. NS pointed out that HYDRO's Craig Warren (Controls) was not able to attend the Meeting due to other commitments. Wayne Snow – Hardwoods Operator – will be available at site for questions.

NG informed HYDRO that an offer has been made by Stantec to buy NG. Stantec is a Canadian engineering firm headquartered in

Action By

Edmonton. Stantec has approximately 7000 employees located in 90 plus offices throughout North America. If the offer is accepted by NG shareholders, a closing could occur in October 2007.

2. **Outage Situation**

NS stated that the Unit was currently operating in synchronous condenser mode and likely will be operating in that mode during the 2 day site visit. An outage has been taken out on Engine/Power Turbine A which will be available for Inspection later in the day. The plan is to take out an outage on Engine/Power Turbine B which will be available for Inspection on Wednesday August 22nd.

3. **Roundtable Discussion on Hardwoods GT**

General roundtable discussion took place on the equipment, buildings and structures at the Hardwoods GT site

3.1 Gas Generators (Engines)

The A Engine has never been overhauled since installation in 1976. The B Engine was last overhauled in 1993.

The Alba June 2007 Borescope Inspection Report was referred to. NS reported that due to the deteriorated condition of Engine A, it has been placed on restricted operation for emergency use only. The Alba inspection found Engine A to have extensive corrosion on various components, as well as damage to a number of blades on the HP section. Engine B was also found to have extensive corrosion, as well as a spacer missing in the HP section which threatens the structural integrity of the unit. Combustor cans on both Engines were showing signs of corrosion and cracks.

NS — In light of the condition of the Engines, RS suggested an option for HYDRO's consideration. RS has a spare engine and starter assembly currently available at the S&S Turbines shop. HYDRO to consider the option.

RS stated that the burner nozzles should be cleaned on a regular basis. There is an ultrasonic cleaner on site. RS suggested that the maintenance technicians should be given instruction on how to properly clean the burners. RS noted there are two styles of nozzles at Stephenville – old style (non-welded) which is easy to take apart and a new style nozzle which is welded and more difficult to take apart.

RS suggested that HYDRO should have a clean spare set of nozzles available for placement in the Engine when EHT problems occur.

NS/JW commented that some work was done on the air inlet system over the years. There is information regarding this work on the Information CD assembled by HYDRO (see section 4).

Action By

3.2 Power Turbine Components

NS/JW stated there had been a series of modifications made to the Curtiss Wright turbines in 1988 (similar changes were made at Stephenville). It was noted that the units were prototypes when installed and ultimately needed design modifications. There is a Report on the work carried out on the Information CD. At this time, there appears to have been no significant work done on the power turbines over the past 20 years.

RS — In response to a NS query, RS will do some research on service providers for the power turbines as well as anyone stocking spare parts for the turbines.

RS — RS noted that thrust bearings are available in the marketplace. Main shaft bearings can be fabricated. Similarly, blades can be manufactured as well. RS stated that if spare blades are available, S&S Turbines can use the blades to make castings. RS will do further research on blading.

There was some discussion on deflector rings disengaging and flying out the exhaust stacks. The mounting system was briefly discussed. FERN Engineering came up with a procedure in the late 1980's for installing the rings. JW noted there have been multiple revisions to the procedure with little success in keeping the deflector rings in place. SC added that the problem goes back 5-6 years with increasing frequency of deflector ring problems over recent years. RS noted that a different mounting system may be needed. No resolves to the problem at the meeting.

3.3 Exhaust Stacks

Work was done on the Exhaust Stacks in 1992. (Stephenville was worked on in 1989. The existing Hardwoods interior silencer panels were revised when the work was carried out. NS was not aware of exhaust stack cracking problems at Hardwoods similar to the situation at Stephenville. JW noted there was an issue in 2006 with the silencer panels. The panels are bolted to the wall of the stack and had dropped down several inches. There were re-aligned by a contractor and appear to be ok now. (There are no known problems at Stephenville regarding silencer panels moving).

The snow doors were redesigned in the mid 1980's. The actuator was changed from electric to pneumatic operation. No major problems with the snow doors. JW stated that the pneumatic actuators are to be replaced in near future.

Action By

3.4 Clutches

NS stated there have been no significant clutch problems over the years. Problems that have occurred have related more to peripheral devices – sticking valves in control system; proximity switches, etc. Uncertain as to whether the clutches were ever disassembled at Hardwoods (noted that a Stephenville clutch was taken apart once – year uncertain).

3.5 Bearings

NS was not aware of any bearing related problems at Hardwoods or any work having been performed on the bearings.

3.6 Lube Oil System & Cooling

The lube oil system is original equipment. There had been a lube oil leak around the bearings, filling a sump with oil. Other than that, NS was not aware of any other problems on the lube oil system.

There is a glycol cooler on the lube oil system (similar to Stephenville). While age and deterioration is an issue, the equipment is in better physical condition that the glycol cooler at Stephenville. In 2006, a new bottom was retrofitted to the cooler. Everything else on the cooler is original equipment, including the piping. The cooling fins have not been cleaned. A new 3 way modulating valve was installed in 2006. No temperature problems known on the lube oil system.

3.7 Enclosures

NS stated that nothing much was done to the engine / power turbine / alternator enclosures over the years. There is a major paint job planned but is on hold.

3.8 Alternator / Excitation System

NS reported that efforts are underway to collect test and other information on the alternator. Key individuals are Robert Stoyles – P&C supervisor for NL east coast (Hardwoods GT) and Clifton

AM — Quinton – P&C supervisor NL central (Stephenville GT). Information should be available in next 2-3 weeks.

AM — KK reported having seen some information on rotor work carried out in early 1990's. (Note – while at site on Day 2, AM had a file on work carried out on the alternator in the early 1990's and late 1980's. AM to provide copies of two Reports contained in the file.

There have been alternator vibration problems which seem more related to the B end of the unit.

The alternator is air cooled (no glycol cooling system as was the case at Stephenville). Ambient air is sucked in, via filters, on one side of the enclosure and discharged on the other. The filter arrangement has been redesigned (not per original).

Action By

3.9 Fuel Unloading & Storage

The fuel unloading system is the original equipment – pumps, valves and piping. The system was reported to work well. JW noted a regulatory compliance issue associated with the fuel oil meters – appears to be difficulty in reconciling fuel usage versus what has been placed in the storage tank within the required percentage allowed by the regulations. HYDRO is working on the issue.

There were originally 2 storage tanks. One has since been removed. A storage tank upgrade was undertaken in the mid 1990's. The tank was cleaned and inspected. The dyke around the tank was redone at that time including the placement of a new liner. A Report on the scope of the work performed is contained on the Information CD.

BK & MR — JW noted that HYDRO engineers have been asked to define a recommended frequency for inspecting the storage tank internally plus a detailed plan for confirming the integrity of the dyke and liner. The plan is required by 2008. JW queried if there is anything Neill and Gunter can refer to in the Report regarding these matters.

MR stated that numerous factors must be considered when assessing the condition of a fuel oil storage tank. These factors can be different at different sites and all have an impact on the frequency for doing internal tank inspections. Factors include – age of tank; type of fuel stored in tank; drawdown rates; location of tank and its environment; etc. The bottom 1/3 of the tank requires special attention.

There is currently a 6 inch pipe that runs between the storage tank

MR

and the fuel forwarding module adjacent to the GT. HYDRO plans to replace this pipeline either fall of 2007 or in 2008. NS stated the pipe may be reduced in size to 4 inch. HYDRO is considering a means of secondary containment either (i) use a smaller diameter pipe within a larger pipe or (ii) place the pipe in a trench. MR offered to do some research on the methodology other Neill and Gunter clients use to transport oil via pipelines..

Action By

3.10 Fuel Forwarding Building

The equipment in the fuel forwarding building is original equipment. The equipment generally works well. The 2 inch piping between the building and the engines was replaced 2 years ago. The piping was originally buried however due to oil leaks was run above ground when replaced. The above ground piping is not heat traced or insulated. The abandoned underground piping was cleaned and capped.

There is an ongoing fuel oil temperature related problem in the winter months resulting in the engine failing to light off. When the engine does run everything is ok. This problem has occurred since the piping was run above ground. HYDRO is looking into the problem.

3.11 Electrical Equipment

AW reviewed some of the observations and comments on the electrical equipment contained in the Stephenville Interim Report – switchgear, cabling, bus duct, batteries, chargers, relays etc. Since the equipment at Hardwoods is similar, AW will be looking for similar items and an assessment of their condition.

There was little in the way of commentary from HYDRO on the Hardwoods electrical equipment. File searches are underway to uncover any pertinent information on equipment refurbishments, replacements and test information.

3.12 Instrumentation & Controls

JMSP also reviewed some of the observations and comments on the control and instrumentation contained in the Stephenville Report. The DCS system at Hardwoods was also replaced in 1999 with an ELSAG Bailey INFI 90 system. It was noted that not a lot of cabling was replaced at Hardwoods when the INFI 90 system was installed unlike the situation at Stephenville. HYDRO stated that the main cabling junction boxes at Hardwoods in some cases was a bit of a “rat’s nest” and should be looked at during the site visit.

JMSP, from discussions with Craig Warren, noted there are unbudgeted plans to replace the vibration monitoring system at Hardwoods. KK reported there is a Bob Stoyles vibration analysis report available on Hardwoods and has been placed on the CD.

JMSP — JMSP queried if there has been an interposing relay problem at Hardwoods as was the case at Stephenville. There was no direct response at the meeting. JMSP to discuss the matter with Craig Warren.

AM stated that Instrumentation spares are listed on the CD.

HYDRO noted that the bearing thermocouple connections at Hardwoods are in rough shape.

Action By

4. NG Documentation & Information Requests

AM provided three CD's on information collected since the Stephenville site visit. Along with the CD's AM provided a Summary List outlining the CD content. The CD's include a mix of information on the Stephenville and Hardwoods sites. A copy of the Summary List is in Attachment 1. With reference to the Summary List, the following are several comments on outstanding information as noted at the Meeting:

- Item 1 – A J.D.E. Work Order List has been provided for both sites.
- Item 2 – Curtis Wright Manual for Stephenville included.
- Item 3 – An itemized list of major upgrades to equipment since 1990 has been included.
- AM — Item 4 – No electrical testing information on the CD (Item 4c) for either site. Information to follow. The P&C information on the CD relates to Hardwoods only. Stephenville to follow.
- AM — Item 5 – The Copy of the Operator's Log is for Stephenville only. Information on Hardwoods to follow in 2 weeks.
- AM — Item 6 – A copy of the semi-annual inspections relate to Stephenville only. Hardwoods information to follow.
- Item 7 – Gas Turbine Test Run Forms for the past 5 years have been included for both sites.
- Item 8 – DOE operating certificate for each site included.
- AM — Item 9 – Electrical single line diagram for Stephenville included. The single line for Hardwoods will be provided later.
- AM — Item 10 – An oil analysis Report for Stephenville has been included. The Report for Hardwoods is in progress and will follow.

- Item 11 – A list of major stocked spare parts applicable to both sites is included.
- Item 12 / 13 -- Copies of the P&C single lines and tripping logic for both sites are included.
- Item 14 – Balance of P&ID's for both sites are included.
- Item 15 – A list of major equipment service suppliers for both sites is included.
- Items 16 / 17 / 18 – Information on instrumentation items outlined in these 3 Items is on the CD

AM

BH queried if any of the requested information, outlined in a NG email of July 24th, relating to electrical testing and visual examination of the alternator and excitation system components has been assembled. AM stated that the email was distributed to various parts of HYDRO for comment/inputs.

Action By

5. Operational Data – Hardwoods & Stephenville

In order to carry out the Life Cycle Analysis work on the various Options as required by the HYDRO RFP, NG requires the following operational information from HYDRO for each Site:

AM / NS

- Annual MWhrs last 5 years – HYDRO to provide.
- *Annual forecasted MWhrs next 15 years. [For this item, it was agreed that NG would use the information for the last 5 years on a go forward basis]*

AM / NS

- Synchronous condenser operating hours last 5 years – HYDRO to provide.
- *Annual forecasted synchronous condenser operating hours next 15 years. [For this item, it was also agreed that NG would use the information for the last 5 years on a go forward basis]*

AM / NS

- Number of successful start-stops last 5 years – Engine A / Engine B / Alternator – HYDRO to provide.
- *Number of unsuccessful start-stops last 5 years – Engine A / Engine B / Alternator. [It was agreed that this information would likely be difficult to collect and the item would be dropped].*
- *Forecasted system changes that can impact the operational mode of each Gt. [Again it was agreed for the purposes of the Study that the Gas Turbines would*

continue to operate in the future as they have in the past regardless of any future system changes].

Action By

6. Financial Data – Hardwoods & Stephenville

AM / NS

In order to carry out the Life Cycle Analysis work on the various Options as required by the HYDRO RFP, NG requires the following financial information from HYDRO for each Site:

- Operations & Maintenance budgets/actual costs for last 5 years – HYDRO to provide.
- An explanation on how overhead costs are allocated between the two sites – HYDRO to provide
- An explanation on how O&M costs are allocated for each of generation and synchronous condenser modes of operations – HYDRO to provide
- Annual projected fuel costs going forward – HYDRO to provide
- HYDRO's cost of money / interest rates for debt & equity / allocation of debt & equity for new capital expenditures / inflation rates going forward – HYDRO to provide
- There was some discussion on whose financial model would be used to do the life cycle cost analysis work. NG can develop a model, however there may be more value in using the HYDRO model used to justify capital work projects, particularly if HYDRO is going to use the Study Report in a submission to its Regulator for capital work on the Gas Turbines. HYDRO to check internally on this matter and will advise.

7. Contract Document Status

The contract document between HYDRO and NG had not been signed as of August 21st. BH noted that two items requested by HYDRO from NG remain outstanding although actions have been taken by NG to provide the information which is from third parties. The two items are (i) registration by NG with the Registry of Companies in NL (Note – the registration certificate was received by NG subsequent to the Meeting and forwarded to HYDRO) and

BH

(ii) registration by NG with the NLCSA Board regarding a Certificate of Recognition. NG is registered with the NSCSA for this purpose.

AM / NS

NG has applied for registration with NLCSA but as of August 21st, had not received a registration certificate. HYDRO to check internally as to whether registration with NLCSA was necessary for the Gas Turbine Condition Assessment Study.

Action By

8. <u>Stephenville Interim Report</u>

HYDRO

BH alluded to the Stephenville Interim Report that was issued to HYDRO on August 17, 2007. NS had an opportunity to briefly review the Report and stated that the content and makeup of the Report was what HYDRO had in mind for the Study. BH welcomed any comments that HYDRO might have on the Report and asked that comments be provided by August 31st.

Day 1 pm – August 21, 2007

9. A site visit was made in the afternoon. At the time, Engine A was on Outage; Engine B was available for service and the alternator was in synchronous condenser mode of operation. A fibreoptic borescope inspection was conducted on Engine A. NG personnel, accompanied by HYDRO personnel, reviewed the Gas Turbine equipment and the balance of plant mechanical, civil, electrical, controls and instrumentation equipment. The alternator and exciter were not available for inspection.

When attempting to startup Engine A and engage it with the rotating alternator, both the alternator & Engine A tripped. Indication was that the clutch had not engaged within a prescribed time, resulting in the trip. Following a post mortem conducted by HYDRO it was determined that the clutch had actually engaged, however in doing so, the cover of the clutch proximity switch had been ripped off, while the clutch was engaging, causing the switch to malfunction and send an erroneous signal to the DCS system. There appears to be a physical interference problem with the proximity switch when the clutch engages. HYDRO noted this problem has occurred before on both engines however more frequently on the A end than the B end of the Gas Turbine. HYDRO to do further investigation to determine and correct the cause of the interference.

Day 2 am & pm – August 22, 2007

Action By

10. The site visit continued on day 2. At the time, Engine B was on Outage; Engine A was available for service and the alternator was in synchronous condenser mode of operation. A fibreoptic borescope inspection was conducted on Engine B. NG personnel, accompanied by HYDRO personnel, continued their review of the Gas Turbine equipment and the balance of plant mechanical, civil,

electrical, controls and instrumentation equipment. The alternator and exciter again were not available for inspection.

Action By

11. Other

AM

HYDRO is asked to provide a copy of the following drawings noted during the site visit:

- No. B1-373-E-010 Rev 3 (Excitation System)
- No. A2-1092 Rev 3 (Station Services Schematic)
- No. HWD – 1 Rev 17 (Hardwoods Terminal) - size 81/2" x 11"

Minutes Prepared By:
Bill Hearn

ATTACHMENT 1

INFORMATION CD – SUMMARY LIST

Information Request:

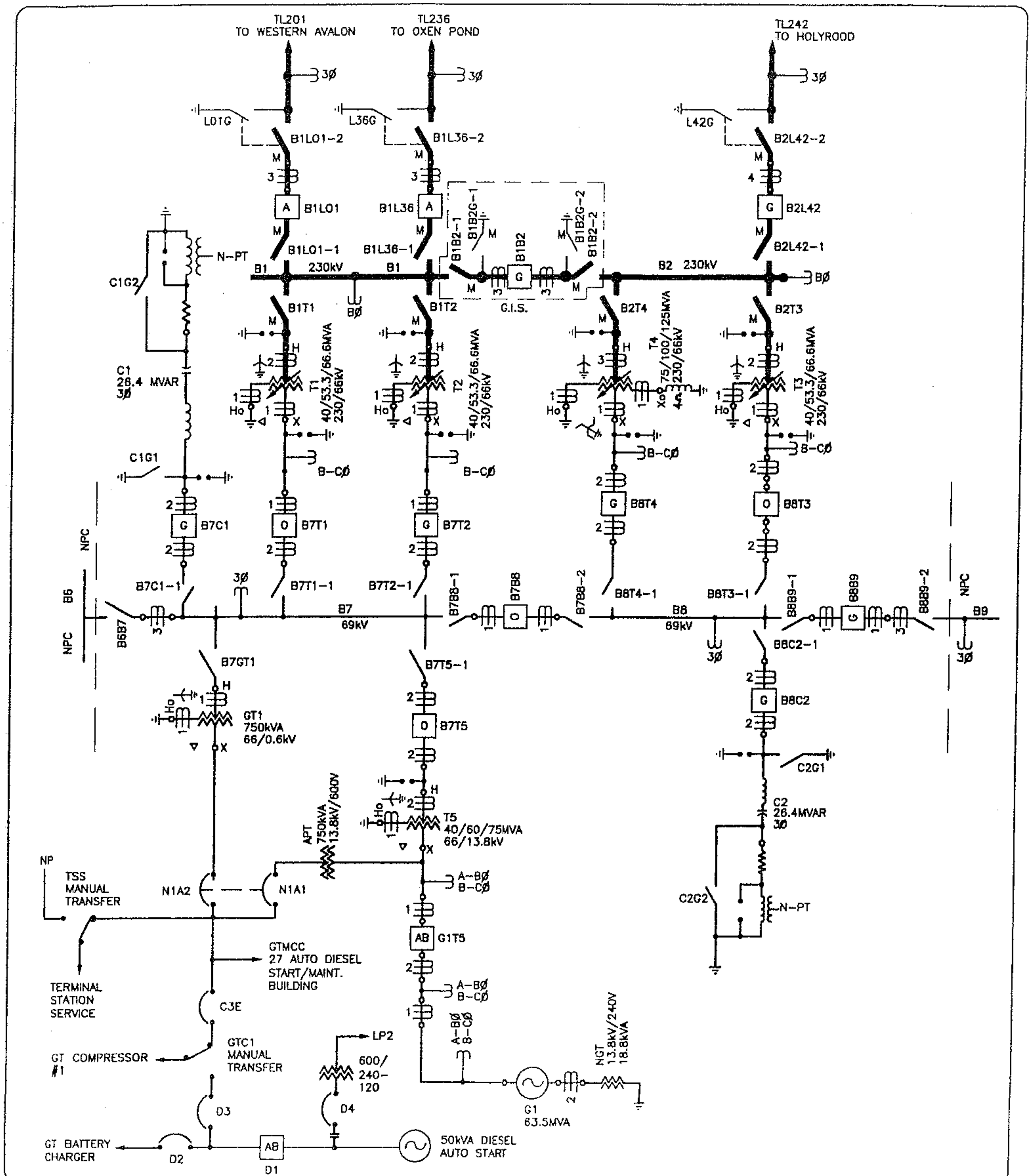
SVL - HWDS CONDITION ASSESSMENT

No.	Item	Action
1.	J.D.E. Work Order List (all items) – electronic format	J.W.
2.	Copy of Curtis Wright Manual for Stephenville – electronic copy	S.C.
3.	Itemized list of all major upgrades – projects done since 1990 including major equipment replacement:	
	(a) Mechanical (G/T overhauls, piping)	N.S.
	(b) Civil/Environmental	N.S./T.C.
	(c) Electrical	D. Hicks
	(d) P&C	C.W./B.W.
4.	Test Equipment Reports over the past ten years:	
	(a) Mechanical	N.S.
	(b) Civil/Environmental	N.S./T.C.
	(c) Electrical (i.e. motors, gen. exciter, switchgear, etc.)	D.H.
	(d) P&C	C.W./B.W.
5.	Copy of Operator's Log back to 1992	S.C./operator
6.	Copy of Semi-Annual Inspections - 21 page document - past 5 years	J.W./S.C..
7.	Gas Turbine Test Run Forms - past 5 years	J.W./S.C.
8.	G/T Operating Certificate from DOE	N.S.
9.	Electrical drawings – single line diagram	D.H.
10.	Oil Analysis Reports + Glycol (last 5 years)	J.W./S.C.
11.	List of Major Spare Parts in Stock - Mechanical - Electrical - P&C	J.W./S.C.
12.	P&C Single Line Diagram	C.W./B.W.
13.	P&C Tripping Logic Diagram	C.W./B.W.

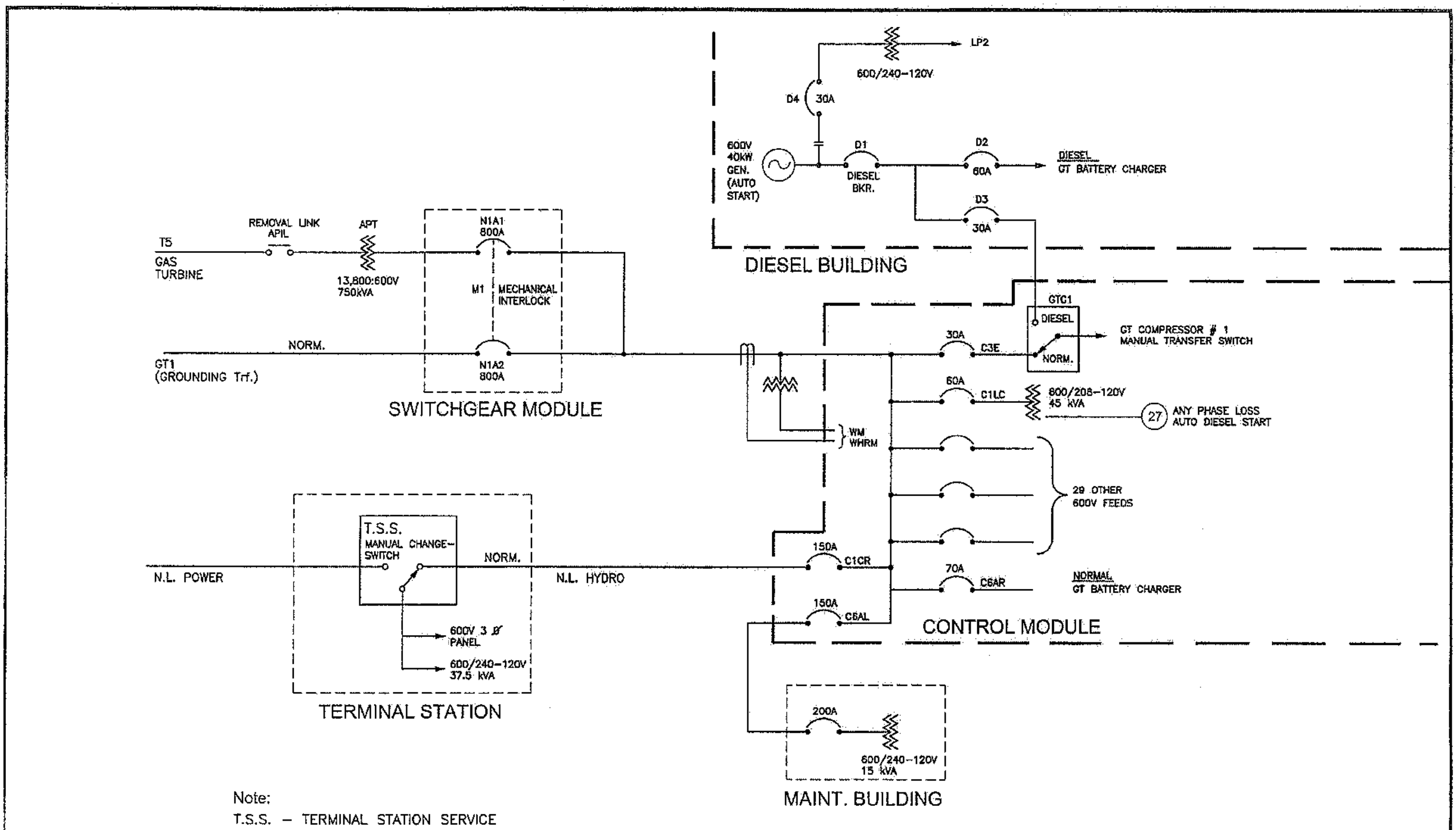
No.	Item	Action
14.	P & Ids - List of IDs?	C.W./B.W.
15.	List of major equipment supplies of past - Mechanical - Electrical - P&C	 N.S. D.H. C.W.
16.	ID type and count per system - Which ones have failed?	C.W./B.W.
17.	List of Field Instrumentation Devices * only if readily available	C.W./B.W.
18.	List of known problems and proposed solution, if any (P&C)	C.W./B.W.
19.	Bob Woodman to coordinate a teleconference between Craig Warren and Jean Marc of NG	B.W./C.W.
20.	Prepare a list of major installations/modifications/equipment replacements that have taken place over the years, with brief two or three lines of description for each item and possibly an associated drawing that would have been prepared or a readily available report. This would include large ticket items such as tank farm upgrades and the P&C upgrade done in the late 90's. It is not expected that many such other items have taken place over the years. To prepare this information some of you may have to quiz some of the people in your section who have worked a lot of years at Hydro as this information may not be easy to find from the files and could prove to be a very time consuming exercise. (a) Mechanical (b) P&C (c) Electrical	 N.S. C.W. K.K/A.O-P.

APPENDIX 2
SINGLE LINE DIAGRAMS
HARDWOODS AND STEPHENVILLE

APPENDIX 2
SINGLE LINE DIAGRAMS
HARDWOODS AND STEPHENVILLE



DRAWN BY: J.T.	REVISED BY: D.R.	NEWFOUNDLAND AND LABRADOR HYDRO	DWG NO HWD-1
APPROVED BY R.S.		SYSTEM OPERATING DIAGRAM HARDWOODS TERMINAL STATION	REV NO 17
DATE 07/07/19			



Note:
T.S.S. – TERMINAL STATION SERVICE

NOTICE:
This Drawing contains intellectual property of Newfoundland and Labrador Hydro (HYDRO) and shall not be copied or distributed in whole or in part without prior written consent from HYDRO. Use of the drawing shall be restricted to purposes of prosecution of a contract with HYDRO.

HYDRO

NEWFOUNDLAND AND LABRADOR HYDRO

NO.	DATE	DESCRIPTION	DWN.	DESIGN.	CHK.	APP'D

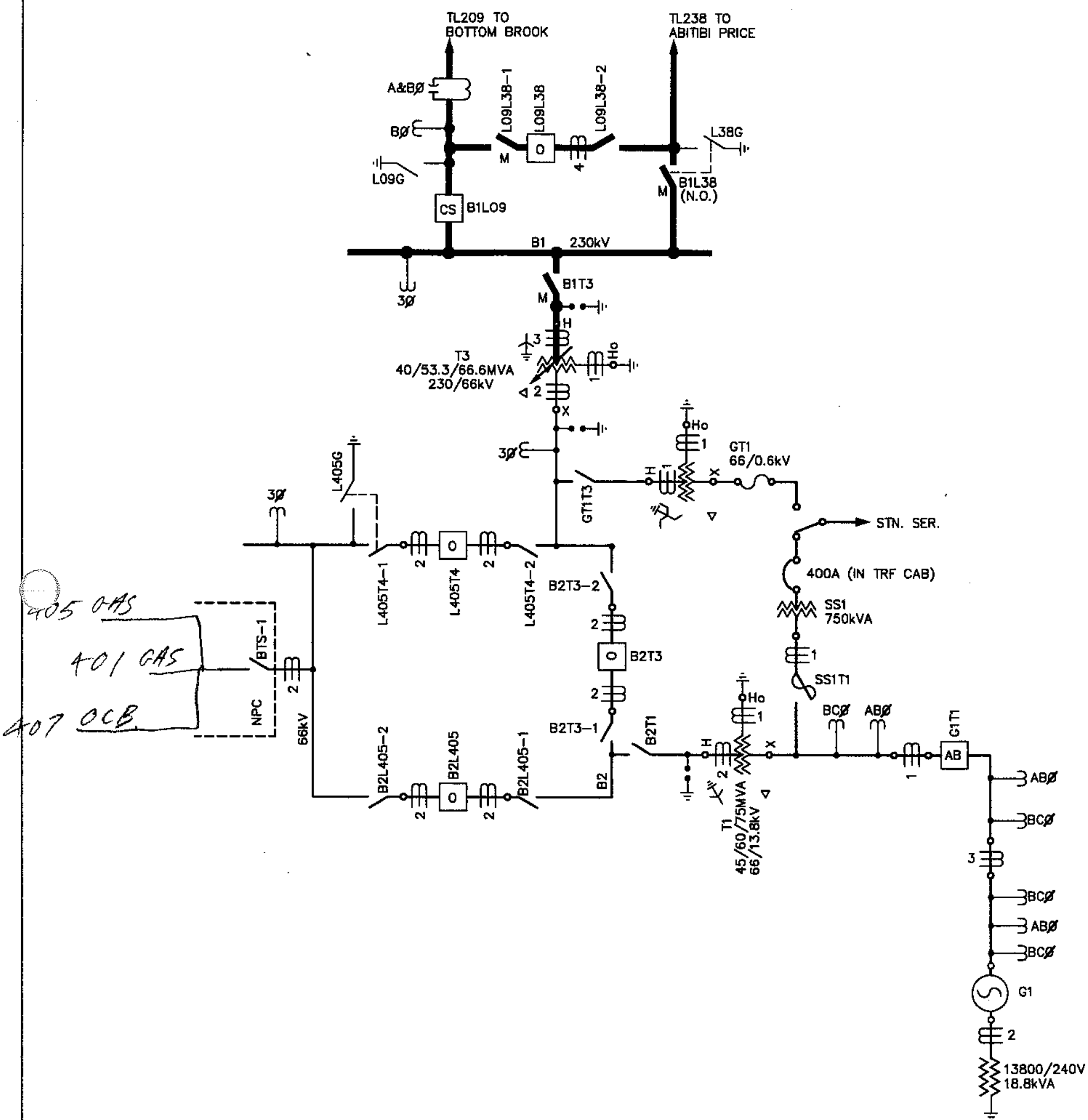
REVISIONS

ELECT.	SCALE: N.T.S.
CIVIL	DESIGNED:
TRANS.	DRAWN: D.R.
MECH.	DATE: 2006/01/03
P&C	CHECKED:
TELC.	APPROVED:

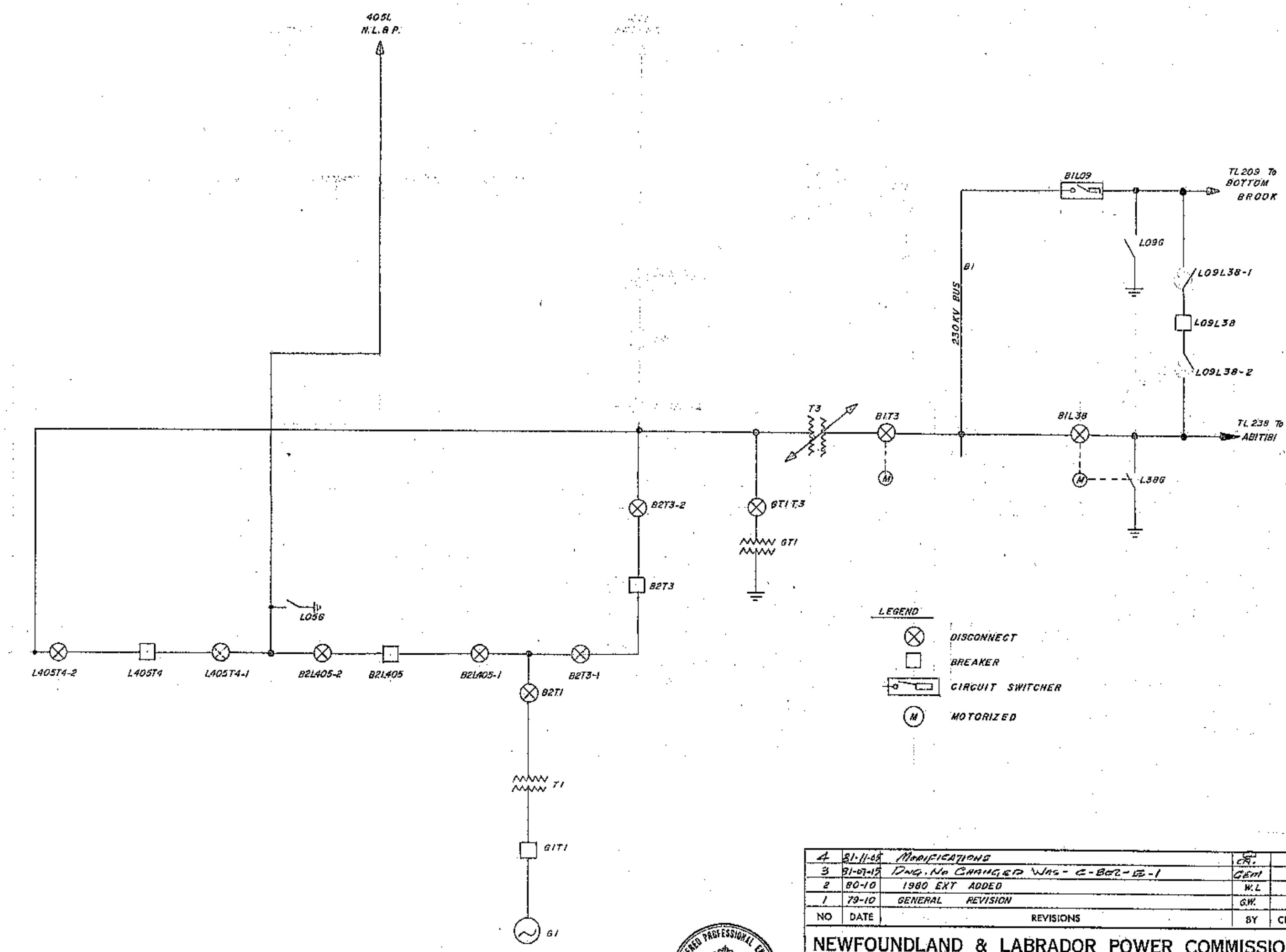
HARDWOODS STATION SERVICES SCHEMATIC

W.O. NO. | DWG. NO. A2 - 1092 | REV. 3

C.A.D.



DRAWN BY D.R.	NEWFOUNDLAND AND LABRADOR HYDRO		DWG NO SVL-1
APPROVED BY C.Q.	SYSTEM OPERATING DIAGRAM		REV NO
DATE 2006/11/22	STEPHENVILLE TERMINAL STATION		10



NO	DATE	REVISIONS	BY	CKD.
4	81-11-05	MODIFICATIONS	CR.	
3	81-07-15	DWG. No CHANGED WAS - C-B02-E-1	GEM	
2	80-10	1980 EXT ADDED	W.L	
1	79-10	GENERAL REVISION	G.W.	

L. G. STURGE
REGISTERED PROFESSIONAL ENGINEER
SIGNATURE
PROVINCE OF NEWFOUNDLAND

NEWFOUNDLAND & LABRADOR POWER COMMISSION
ST. JOHN'S, NEWFOUNDLAND

STEPHENVILLE TERMINAL STATION
SINGLE LINE DIAGRAM

Reference Dwgs. DWG. NO	TITLE	APPROVAL

SCALE N.T.S.	DESIGNED BY	DRAWN BY J.G.
CHECKED BY	APPROVED BY MS	DATE AUG. 16 '74
PROJECT NO.	SHEET.......OF.......	DWG. No C-319-E-1

APPENDIX 3
HYDRO JD EDWARDS MAINTENANCE ACTIVITIES PRINTOUT
HARDWOODS AND STEPHENVILLE

APPENDIX 3
HYDRO JD EDWARDS MAINTENANCE ACTIVITIES PRINTOUT
HARDWOODS AND STEPHENVILLE

Hearn, Bill G.

From: NSeymour@nlh.nl.ca
Sent: Friday, July 13, 2007 2:29 PM
To: Hearn, Bill G.
Cc: JWheeler@nlh.nl.ca
Subject: NLH Gas Tubine Assessment

Attachments: SVL GT History.xls; HWD GT History Rev 1.xls; GASTURBINE2006 002.jpg; GASTURBINE2006 001.jpg

SVL GT History.xls (51 KB) HWD GT History Rev 1.xls (144 ... GASTURBINE2006 002.jpg (705 KB... GASTURBINE2006 001.jpg (706 KB...

Bill,

Attached are lists of items, briefly described, summarizing operating problems we have experienced over the past 10 years. These were extracted from a much larger list that records all maintenance actions. In addition, the diary text below highlights some of the particularly troublesome incidents as noted by Jim Wheeler.

Nelson
----- Forwarded by Nelson Seymour/NLHydro on 07/13/2007 02:43 PM -----

James Wheeler/NLHydro
07/03/2007 04:03 PM

To: Hughie Ireland/NLHydro@NLHydro
cc: Nelson Seymour/NLHydro@NLHydro, Steve Carter/NLHydro@NLHydro
Subject: Re: Update of History at SVL and HWDGT(Document link: Nelson Seymour)

Have attached the up to date log I have been keeping for HWD and SVL combined. Please find the stored testing and trend data on the X: drive as follows X;\Gas Turbine Trending (SVL-HWD). This is what has been scanned and stored to date.

Regards
Jim

(See attached file: SVL GT History.xls)(See attached file: HWD GT History Rev 1.xls)

2006-01-04
HWD GT Fuel transferred from Hydro Place to HWD (21,418 liters). arranged by Norman Bungay. Transferred by Crosby's Industrial using the same truck as is used to empty the sump at HWD.

2006-01-23
Due to system load requirements HWD and SVL GT's were required for generation.

0702 hrs HWD GGB was started in Generate mode. At that time GGA failed to start.

0706 hrs SVL GGA failed to sync after 2 attempts.

0755 hrs HWD GGA was started from local control and put on line. Both units were on line at this point with approximately 30 MW load total.

0901 hrs SVL GGA put on line and loaded to approximately 20 MW. Maximum available due to EGT Spread alarm. The unit was monitored locally and kept at 20 MW .

1048 hrs HWD Unit tripped with approximately 28 MW. Investigation indicated the DC breaker for unit controls (both GGA & GGB) tripped. DC breaker was reset and unit (GGA & GGB) given a start command. Breaker tripped again during the attempt to start. In local control GGA only was given a start command resulting in the breaker again tripping. GGB alone was then given a start command and started successfully. It was determined that the DC fault was directly linked to the operation of GGA. GGB was then loaded to 17 MW to support system load. At that time technicians at site were investigating the problem with GGA.

1359 hrs HWD GT tripped (GGB) with at 17 MW / 17 MVAR due to anti ice fail. Crew on site removed anti ice valve and solenoid from GGA and replaced the failed unit on GGB with it. Unit was made available at 1658 hrs. At that time the anti ice unit was removed from GGB at SVL and shipped via air to St. John's to arrive at 2100 hrs.

1658 hrs HWD GGB put on line and loaded to 15 MW. Restricted to 15 MW due to EGT Spread alarms.

2148 hrs HWD GT was switched to Sync Condense Mode as per system requirements. During this time the anti ice unit from SVL was installed on HWD GGA and trouble shooting of the DC cct. continued.

2208 hrs HWD tripped at 0 MW / 0 MVAR while attempting to switch GGA to generate.mode. DC breaker trip. Further trouble shooting at that point identified a failed cable in the DC control cct. The cable was replaced and a GGA start was again attempted. The DC breaker did not trip at this point but attempts to start GGA were unsuccessful due to GGA Incomplete Sequence. Several attempts were made to start GGA and at approximately 0245 hrs crews discontinued work. HWD was left with GGA unavailable and GGB available up to the 15 MW restriction.

2006-01-24
0208 hrs HWD GGB on line.

0216 hrs HWD switched to sync condense mode.

1015 hrs SVL GGA sustained a controlled shutdown at approximately 5 MW due to EGT spread deviation. At that time ECC gave GGA a remote start command and set load to 15 MW. In ramping to 15 MW the trip (controlled runback) occurred.

1026 hrs SVL GGA. In local control the operator started GGA and kept the unit at min load (2 MW) for 10 minutes to let the machine stabilize while monitoring EGT. After 10 minutes to EGT was stable at 65 deg. C and he loaded to unit to 5 MW as required by ECC.

1200 hrs Crew returned to HWD to further troubleshoot the problems with GGA incomplete sequence. They indicate the incomplete sequence problem appears to be associated with the cable issue from last night and a complete unit outage is required to further investigate. An outage is scheduled for 2006-01-24 (2100 hrs) to continue investigating.

2006-01-24 HWD GGA DC breaker trip was identified as failure of the snubber circuit for the fuel solenoid. Zenor diodes across 401 and 4 (fuel solenoid) was shorted causing the DC breaker to trip during the starting sequence. The snubber was removed and unit returned to service without the snubber. Currently working with P&C and engineering to identify replacement parts.

2006-01-30 to 2006-02-03
SVL GGB Combustor cans were removed from GGB and replaced by a refurnished set stored in HWD. Rolls Royce representative Alain Joseph was on site for this. There were no apparent defects identified with the removed cans other than some erosion near the interconnector port on #2. Alain indicated this would not create the EGT problems we are experiencing. There were design differences in the cans. The manufacturer indicated the cans from HWD were Phase 1 and the existing cans on GGB were phase 2. Phase 2 is a upgrade to increase the time between maintenance overhauls. The manufacturer indicated putting back phase 1 cans is not a problem.

2006-02-05 2329hrs. SVL GGA failed to start (3 attempts) due to exhaust spread. Ray Rowe made serval adjustment to the fuel transducer however no luck. At present unit is unavailable for system.

2006-02-07 & 08
SVL GGA logic was modified to inhibit EGT Spread Deviation shutdown anf trip until the engine reaches N3 speed greater than 3540rpm (clutch engaged) and generator is at minimum load (2 mW). EGT spread deviation alarm will be enabled during startup but shutdown (runback) and trip are disabled. Also at that time the screen graphics was modified to show EGT Spread Deviation on both GGA and GGB. GGA was test run to 25 mW successfully.
A work order is in place to make the same logic changes to SVL GGB an HWD GGA and GGB.
HWD GGA & GGB logic changes are scheduled for the week of Feb. 13, 2006.

2006-02-08
SVL GGB burners. Rolls Wood reported SVL GGB burners have been inspected and 4 of the 8 require extra repairs. Revised quote for the inspection and reconditioning of these burners is 17,519.66 British Pounds.

2006-01-15
HWD GT The upper bearing on Fan # 2 in the glycol cooler was identified as being noisy. Bearing detail was identified and a replacement is being shipped to be installed 2006-02-18 & 19 (Sat & Sun) due to the availability requirements of the gas turbine. On 2005-05-05 the lower bearings on the same fan were found noisy and both lower bearings were replaced. Provision is made to replace the upper bearing on Fan # 1 as soon as the work can be scheduled.

2006-02-20
HWD GT tripped at 9 MW during testing to determine if the glycol cooler could maintain enough cooling to the unit with #2 fan turned OFF. Unit tripped on Low Liquid Fuel Pressure. Problem was investigated and it was determined the motor operated fuel valve had malfunctioned. It appeared to have overtravelled leaving no indication to the DCS system whether the valve was open or closed. Valve was operated several time and operated correctly. Unit was returned to service. One possible reason is the valve bay have been iced outside and when the ice broke free it overtravelled due to excess torque being applied.

2006-02-23
SVL GGA experienced a EGT spread deviation shutdown at 1128:44 hrs on Feb. 23 during startup and loading for generation requirements. Craig Warren and P&C West are investigating the trend logs to determine the cause of runback as the EGT spread deviation indicated 53 deg C was reached and shutdown occurs at 60 deg C.

2006-02-24
HWD GT Inverter failed. Inverter bypassed to station service AC until outage can be apptoved to replace.

2006-02-24
HWD GGA. Unable to load GGA beyond 5 MW with a fuel valve position of 48 % which should represent half of full losad (approximately 12 MW).
All three fuel filters on GGA replaced without success.
Jordan valve removed and calibrated at Diesel Injection without success.
During testing it was identified that one of the igniters on GGA was not working. Igniter was replaced.

2006-02-25
HWD GGA tested for load capacity and was only able to achieve 8.8 MW at 100% fuel valve. Fuel restriction still an issue. During shutdown and transfer to sync condense the clutch on GGA failed to release. The clutch casing had to be removed and the clutch physically separated. GGA will not be available for service in any capacity until the clutch is removed and repaired. During the emmediate requirement to restore HWD sync condense it was identified that when GGB was started, the motorized main fuel valve did not open.

2006-03-06
HWD GGB. Old burners removed and replaced with overhauled burners taken from SVL GGB. Unit was run up and went into alarm (EGT Spread Deviation) at 18 MW. Unit released with same 15 mw load restriction until further notice.

2006-03-13
HWD GGB. Engine fuel hoses inspected and found okay. Hoses were exchanged with GGA as well with no success to correct the EGT spread deviation problem on GGB.

2006-03-14
HWD GGA. Total outage today to do the following.
1) Oil solenoid on GGA clutch replaced. A oil line to the solenoid was identified as damaged and replaced also.
2) Inverter at Gas turbine replaced.
3) Anti ice valve replaced on GGA with rebuilt that was removed Jan 23, 2006.
4) Failed cable to fuel forwarding module replaced.

During start up problems were experienced with the supply breaker to the glycol pump tripping. Another breaker (not sized exactly as the failed one) was used to replace the failed unit. A new breaker sized the same as the original is being sourced. New breaker on order.
The repaired anti-ice valve failed to operate and showed the same problems as when it failed originally , 2006-01-23. It was removed and replaced with the unit drom SVL GGA. Failed unit sent back to Ozark for re-evaluation.
GGA was started and run to 1300 rpm at which time a fuel leak was detected on the fuel line to engine. On rundown it was not determined definitely if the clutch operated correctly. Both engine and generator were coasting at the same time. GGA clutch was dissengaged when GGB was started to put the unit on in sync condense.

2006-03-15
HWD GGA.
Failed anti-ice valve returned to Ozark for evaluation. Crew repaired leaks on GGA fuel lines.
Ran up GGA and tested manual valve in fuel return line. Testing indicated

this bypass circuit is not our problem.
Next step is to replace GGA fuel actuator to identify GGA not able to get to full load.
On unit stop (GGA) today the clutch failed to separate!!!!!

2006-03-16
HWD GGA.
Clutch solenoid valve sent to Diesel Injection for inspection.
To determine the loading issues with GGA, the manufacturer suggests replacing the fuel distributor. We have a spare distributor at HWD.
Mechanics installed today a fuel pressure gauge to monitor the fuel pressure into the distributor.
The mechanics installed a pressure gauge on the input line to the fuel distributor on GGA today and ran the unit to 8 MW. Pressure @ 8 MW and full valve was recorded at 800 psi.
Can you confirm if this pressure is what would be expected.
HWD sump was pumped out today.

2006-03-17
HWD. Nelson discussed with Rolls Wood. RR indicated the distributor is most likely not the issue with GGA fuel and loading. They referred to a servo dump valve as as possible suspect and Nelson will persue details with RR today to determine a test procedure or process to investigate the servo dump valve.
RR indicated the distributor is considered a prime suspect for the EGT spread seviation issuses with GGB and recommends replacing it on GGB.
Plan for today is to replace the distributor and final filter on GGB and test the unit.
Nelson will also check on the status of the anti-ice valve at Ozark as well as the clutch solenoid at Diesel Injection.
Also Reg suggested installing a pressure gauge on on of the output lise from the distributor. Is this a good idea and if so what should we expect to see. Are we wasting our time here and should we go directly to replacing the distributor.
By the way the clutch on GGA failed again on run down.
Fuel distributor replaced on GGB as well as final filter and unit test run to 18 mW at which time the EGT spread deviation became active again.
Changing the distributor on GGB did not correct the problem on GGA.

2006-03-18
HWD GT
High sump alarm recieved from HWD. Investigation found sump full. Also a local alarm indicating main lube oil level low. Found sump full of lube oil. Sump was emptied, unit shutdown and investigation started to identify the source of oil leak.

2006-03-19
HWD GT
Oil leak was found to be the expansion joint to the rear journal bearing on turbine A. Repairs were made and 6 drums of oil required to replace that lost from the main lube oil tank.

2006-03-20
HWD GT
Oil sourced from HRD plant and process to top up tank today. 10 barrels ordered from HRD.
Mechanics are checking the remaining expansion joints in the lube oil system today for possible leaks and integerity.
The events of Saturday indicated the lube oil level low alarm is not seen by the ECC. This low level alarm inhibits the oil heaters from coming on thus blocking a unit start.

Wayne's note on Weekend findings:
Guess you know by know we had high sump alarm over the weekend.
Sump was pumped out Thursday and again on Saturday.
The only indication ECC had was high sump alarm.
On site there was also a lube oil level low alarm.

ECC did not have any indication of this alarm.
It was only after we shut the unit down (take off sync cond) did we loose the green lights.
ECC should have this alarm and it should be called MLO level low alarm.
Most all the oil that was loss was collected in sump.
ECC keeps getting high temp alarm on the bearings and Gen alarm.
On site we have MLO tank temp low alarm, the heaters will not cut in, with a low level
oil alarm, you don't want the heaters on, in case they are out of oil.
These alarms needs to be straightened out asap.

There was an oil leak on the expansion joint to the rear journal bearing on turbine A.
We need six drums of tresso 32 oil.
We need a work order to cover work done this weekend.

Note to Hughie to request full review of inputs to DCS to determine adequacy of alarm functions and inhibits especially to ECC.

2006-03-21
HWD GT
More lube oil Teresso 32 required to bring the reservoir up to full mark.
Another 13 barrels ordered from HRD and system filled today.
The clutch solenoids on GGA and GGB to be switched today with the intent to confirm the failure mode of GGA clutch. Flex lines to both solenoids will be replaced as recommended my mechanic.
Repairs to demister scheduled for today.
Complete inspection of oil line flex connections today and tomorrow.
Note to Steve to discuss PM checks to include inspection of lube oil flex connections as well as ckecks of lube oil level at both HWD and SVL.
Clutch solenoids were interchanged on GGA and GGB. Both GGA and GGB were run up. GGB functioned correctly and GGA clutch failed the same as prior to changing the solenoid. (No improvements to GGA clutch problem)
During the run of af GGB the intermediate filter housing o-ring failed causing a fuel leak. O-ring was replaced.
Sump high level alarm was modified to be indicated at both ECC and local.
Before this only the ECC received the sump high level alarm.

2006-03-22
HWD GT
P & C to perform checks today to confirm the controls to GGA clutch solenoid are working correctly. Monitor solenoid voltage during run-up and shutdown.
P & C found fuse blown in the clutch solenoid cct preventing the solenoid from operating. This is a output from the DCS. Blown fuse was a result of a failed snubber. This snubber is located in the same jct box as the one that failed 2006-01-23 in the liquid fuel valve cct.
Snubber was removed and the unit returned to service. This cct does not have nlown fuse indication. Snubber removed and fuse replaced. GGA clutch tested for operation and is now functioning correctly.

2006-03-23
HWD GT
Checked DC controls to fuel system on GGA and found a failed snubber on Dump Servo Valve SV-LF-1. Snubber removed and unit tested to normal load (24.8mw) without alarm. HWD GGA back to normal nonrestricted operation.
Anti-ice valve will be tested on GGA at the first opertunity and if okay SVL GGB anti-ice will be returned to SVL.

2006-03-24
HWD GT
GGB Nelson recommending swap burners 1 (hottest) and burner 4 (coldest) and test run monitoring temps. and alarms. Targetted for today to identify GGB spread deviation issues.
Old burners from HWD GGB are being transported today to be installed on SVL GGB.

Still waiting on anti-ice testing at HWD before getting anti-ice back to SVL GGB.

Results as follows:
Reg interchanged burners 1 & 4. No change, got exhaust spread alarm at 19 MW.
No 1 burner the coldest at 626
No 2 burner 654
No 3 burner 690
No 4 burner the hottest at 708
No 5 burner at 670
No 6 burner at 689
No 7 burner at 685
No 8 burner at 675
Exhaust average 674
B temp reference 766
Alarm spread comes in at 50

Also fuel flex hoses on burners 1 and 4 (GGB) were switched withsame on GGA.

Interchanging the flex hoses and swaping burners had no change to GGB EGT Spread Deviation.

2006-04-07
SVL GGB (Hughie's Note)
Ron Mercer adjusted fuel transducer to be camp. with our new cans that' fitted with the old burners from Hardwoods.We had a couple off failed starts getting the proper setting.
15:30 hrs 5 MW
15:33 hrs 10 MW
15:36 hrs 15MW
15:39 hrs 20 MW
15:42 hrs. 24 MW (UNIT BEING CONTROL BY TEMPERATURE LIMIT)
The spread didn't exceed 25 degrees,when we were at 24 mw it was 22 degrees.

This is a quick note to inform you that Stephenville Gas Turbine End B was tested today, after installing the burners from Hardwoods (GGB), and the unit reached full capacity without any exhaust gas temperature problems. Our next step is to have a discussion with Nelson on Monday to develop a plan of attach for Hardwoods. From this experience it appears the combustion cans in Stephenville were suspect as the spare combustion cans from Hardwoods were installed at Stephenville when the burners (that are now in Hardwoods) were removed and sent to Aberdean for refurbishment.

2006-04-17
Work plan for this week to include replacing of last glycol cooler fan bearing. Top bearing on fan # 1.

2006-04-19
HWD GT
Swapped burners 2 & 5. on GGB. No change, still got exhaust spread temp alarm at 19 MW. I have temperatures and load readings at 5 MW intervals, which I will deliver to N. Seymour tomorrow. Engineering requested to make arrangements with the manufacturer to be on site to oversee the removal of cans from SVL GGB and install same in HWD GGB. This is required to prove if HWD GGB is a cans issue before major investment to fix HWD GGB cans.

2006-04-21
HWD GT
Pressure tested pipeline going to sump, by capping off line in sump and filling line with water, from drain in floor in fuel forward pump house. Checked pipe and 1/2 hour later, no sign of any water. This is the new pipe line that was installed less than a year ago. This test is a result of

the sump being filled with water at a higher rate than previously recorded. Request to engineering for recommendations.

2006-04-07
It was identified that an excessive amount of water is being collected in the HWD GT sump system. Leak test indicates there is a failure in the underground piping. On 2006-07-04 the piping was exposed near End A and a break was found in the pipe joint. Both sections of pipe were tested from the broken exposed area and found the okay except for a failed backflow valve from End A air intake module. Valve was replaced and repairs made to the ruptured joint that was exposed. Work order in place to test system in November, 2006 and spring of 2007.

2006-07-03
GGA failed to start due to a failed proximity switch on GGA clutch. Switch was replaced and unit made available on Tuesday, July 4.

2006-07-16
Note of plan from Hughie to Rob Cater.
In an effort to bring both Hardwoods and Stephenville up to their full 50 MW rating we plan to remove the combustor cans from Stephenville End B (these are the cans that were installed at S'Ville End B and improved the rating from 10 MW to 25 MW) during the week of Aug 7, 2006 and then reinstall the old cans. This will de-rate the unit at S'Ville to 10 MW but will ensure both ends are available for starting for synchronous condenser purposes.

The cans removed from S'Ville will then be transported by road on Aug 14, 2006 and installed in HWD End B. During the same outage to remove the cans at Hardwoods we are also doing an inspection of the LP Turbine blades as recommended in a service bulletin. It is important to note all work at Hardwoods will be under the Supervision and direction of Rolls Royce representative . At the end of this work it is hoped we will have a good idea of the condition of the LP Turbine blades and (hopefully) have HWD End B back to a 25 MW rating (up from the current 15 MW rating).

If everything above goes as planned we will then have to make a decision on sending the combustion cans that come out of HWD End B back for refurbishment (estimated at a cost of ~$300 k) and bring S'Ville End B back to it full rating.

2006-07-26
Reported by Wayne Snow.
Just faxed a work request to Steve, to replace the seals on MLO pump 1. Pump 2 is in service for now. A complete outage is required to remove pump,
(a good time maybe Aug 1, outage) since the complete unit must be down. The pump is normally taken out, brought over to the shop and serviced. We use a blank cover to replace where pump is too, so we can use unit while repairs are being made. Then we will need another outage to re-install
pump. Mechanic required.

2006-08-04
During a run up this past week on Hardwoods End A , we experienced a problem with the anti-ice control circuit that initiated a trip on the unit. After some testing we cannot seem to duplicate the problem. However we have concern with the anti-ice valve on end A and suspect this is the root cause of the problem. Our next step is to remove the anti-ice valve from End B in Stephenville on Tuesday (August 8, 2006) and ship it via air to St.John's to be installed and tested at Hardwoods on Wednesday August 9,

2006.

As a result, End A at Hardwoods shall be restricted from being operated in generate mode but can still be used to place the unit in synchronous condense mode as required. Also for your information Stephenville is fully available up to and including August 7, 2005 (at which time End B will be taken off line for combustion can removal) but Hardwoods is restricted to 15 MW on End B only.

If you have any questions regrading the Gas Turbine over this coming weekend please contact myself at 486-0350 or Jim Wheeler at 486-1042

Installation of valve from SVL delayed until 2006-08-11 as per ECC request. Outage changed.

2006-08-11
Anti-ice valve replaced today with unit from SVL GGB and works properly without alarming.
Testing don on valve from SVL GGB as well as failed valve from HWD GGA. Test detail is recorded on work order 533666 and it was concluded the limit switches embedded in the valve motor are not operating correctly causing the motor to want to run. This is pulling the 24 Vdc power supply down causing false indication to the DCS system which makes both GGA and GGB not available. The valve removed from HWD GGA has ben repaired locally as well as being sent to the UK some years ago for repair. We are unable to make repairs to the valve limit switches.

2006-08-14
Scheduled outage to HWD GGB to perform low pressure turbine inspection and replace combustor cans with those (new / refurbished) that were installed in SVL GGB and proven to get SVL GGB to full load without EGT Spread alarm. Schedule was delayed as it was identified on Monday that the engine (HWD GGB) had to be removed for LP inspection. At that point it was discovered the lifting beam for such was at SVL and had to be transported to HWD. There was no actual delay as the engine had to be readied as well as an extension beam had to be installed prior to the lift. The extension beam had to be modified as to accomodate the mounting bolts even though it was used previously. LP turbine inspection was completed by Steve Press of Rolls Royce (from UK) at 1530 hrs on 2006-06-16, (Wed). Engine GGB was reinstalled and the combustor cans replaced with the set removed from SVL GGB. Significant work was involved from Wed 92006-08-16) to Monday (2006-08- 21) to return the engine and replace cans. Dowels in the engine shroud were very difficult to remove and some were damaged during removal.
HWD was test run Monday afternoon (2006-08-21) and results are as follows:
HWD GGB - Before cans changed out reached 19 MW before EGT Spread Alarm.
HWD GGB - Test run after cans changed an EGT Spread alarmed at 22 MW.
Outdide ambient temp at that time was 22 deg C.
HWD GGA was also run at that time and maximum output at that time was 22.3 MW at which point the unit went into high temperature control.
Alain Joseph of Rolls Royce (Canada) was on site for changeout of combustion cans. Due to a death in the family he was unable to stay for the run up.

2006-08-16
SVL GGA
Failed to start on 2006-08-16 and below are the investigation results.

(See attached file: GASTURBINE2006 002.jpg)(See attached file: GASTURBINE2006 001.jpg)

Jim:

Ron Mercer came across a relay burnt out at STVL GT , last week. It is the relay that sends power to the fuel re-circ. valve.
He also found fuses blown in the card that powers this valve, (both ends

).
After much discussion, it now appears that we have a wrong application of this relay here.

The relay is a miniature (Micro-electronic MZH A 001 48 10)
It has a 24V coil , and contacts rated for 10A @ 250 Vac.
From literature obtained on this relay we see that at 125Vdc, it should be interrupting no more than 300mA, and in fact the manufacturer says its relay is not designed to switch DC current/voltage.
We are interrupting at least 3A inductive with this relay and as a result have burnt a hole in it. (welded contacts).

Ron is in the process of wiring in interposing relays (Potter Brumfield KUEP-11D15-110) which have contacts rated at 3A @ 150Vdc, and we will have to
obtain some relays to replace those burnt up.

The issue is that upon searching the Dwgs. / Cards etc.... he has found at least eight more solenoids that are running their power through these same type relays and again these appear to be not rated to carry / interrupt this load. (Fuel Control and Starter Control)
There may be other circuits undiscovered.

This appears to be designed this way, from Bailey, I assume. It seems that some circuits got interposing relays and some didn't.
I would imagine that at HWD GT we have a similar situation.
There was also a question raised as to whether the Agastats we are using are rated for DC interruption.

I think Engineering should look at this with regard to obtaining a suitable interposing relay , if that is the solution, and what other circuits here are this way.
We will also need mounting gear , wire , din rail,bases, etc....

I think it is probably just a matter of time before other relays on these cards are burnt resulting in more problems.

Clif Quinton.

2006-08-24
HWD GGB
Plan for next week is to install the burners / nozzels that are / were in SVL GGB in HWD GGB and unit will be test run with refurbished cans from SVL GGB along with existing burners from SVL GGB. This combination of burners and cans worked in SVL GGB to get full load on SVL GGB. The cans removed from HWD GGB last week will be installed in SVL GGB and depending on the results of HWD GGB a set of burners will be shipped to SVL GGB.

2006-08-24
Work plan for next week. HWD and SVL
Please proceed with the following plan to investigate EGT Spread problems at HWD GGB and SVL GGB.
1) Combustor cans were removed from SVL GGB (overhauled ones) and installed in HWD GGB last week.
2) Overhauled burners are now in HWD GGB.
3) Install burners that were removed from SVL GGB in HWD GGB. These burners were sent to HWD along with the cans that were removed fron SVL GGB recently. This will then give the same burner / can combination in HWD GGB as was in SVL GGB that allowed SVL GGB to achieve full load without alarm.
4) Test HWD GGB for maximum load.
5) Ship cans that were removed from HWD GGB to SVL and install in SVL GGB.
6) When the results of HWD GGB are know a decision on the next move will be made.
Please schedule the work for HWD and SVL so HWD can be tested and the cans will be install in SVL GGB waiting the burners from HWD (which set to be

determined.
Thanks
Jim

2006-09-21
Note from Nelson On HWD GT MLO Temp trip.
I understand that the controller for the temperature regulating valve was replaced yesterday and that the engine was ran up to 6 MW with normal temps. Avg exh. gas temps are over 200 C higher above 20 MW. I suggest we do a test run to full load to ensure there are no further problems.

2006-09-22
Note from mechanic (Mike Penny) on resolution of HWD MLO temperature problem.
The glycol system seems to be working OK now.
We had 44 MW on unit. The MLO temperatures were 150 & 120. The glycol was 95 & 105.
We took apart the regulator on the glycol system, replaced O-ring, cleaned seats, made several adjustments.
We took apart the Y strainer and cleaned. Checked heat exchanger on the oil system, Had to remove a drum & 1/2 Glycol and replaced some, glycol due to dirt in glycol.
The unit is passed back to ECC, there are a few minor leaks we have to look at, then we are out of here.

Mike

2006-09-29
Prior to the runup of SVL GGB a new / overhauled anti-ice valve was installed. The valve was acquired from Alba Power and the failed unit (originally from HWD GGA) was sent returned to Alba Power as a rebate on the unit we installed in SVL GGB.
This past week the combustor cans and burners were installed on SVL GGB and as a result of today's test run new load availability have been achieved.
The following reflects the present availability of both HWD and SVL GT's.

Hardwoods: (No change from last update)

END A - 25 MW
END B - 21 MW

Combined with END A and END B running at the same time : 42 MW (This is not the sum of both ends but 2 x the lowest capability)

Stephenville:

End A - 25 MW
End B - 22 MW

Combined with END A and END B running at the same time : 44 MW (This is not the sum of both ends but 2 x the lowest capability)

2006-10-19
A schedule and test procedure has is in place to perform monthly run up testing of the units at both HWD and SVL starting October 25 at SVL and November 8 at HWD. This will exercize the units and verify their operation as will identify equipment failures and enable repairs to be made in a scheduled manner.

2006-10-20
SVL GT
Just a quick note to let you know that GGA was released to the system @13:33hrs,we did a run to light-off to check
the newly installed starter air regulator-everything went well.

Hartery
Also the RTV coating and general painting / repairs were completed as of 2006-10-20.

2006-11-11
HWD GT returned to service after two week outage to complete the following work.
1) Replace AVR with ABB on site for commissioning and in-service checks.
2) Glycol cooler housing replaced by M & M Engineering. Work completed with final painting outstanding due to time restraints. New work was primed only. Final painting to be rescheduled in 2007.
3) Exhaust stack repairs to insulators completed by Black & MacDonald. Inspection of stacks prior to repairs indicated further deterioration from previous inspection in August 2006.
4) Main lube oil pipe and strainer replaced.

2006-11-15
HWD GGA & GGB Deflector Rings
Daily inspection identified the deflector ring on GGB had become displaced and was expelled from the unit through the exhaust stack. Ring was replaced on 2006-11-16 and GGB made available at 2130hrs on 2006-11-16. On 2006-11-16 operator also found displaced deflector ring on the ground and is suspected to be from GGA. Replacement ring was shipped from SVL for GGA. New rings ordered as the spares are all used.
Outage scheduled for GGA to replace deflector ring on 2006-11-16 but was cancelled due to windmilling on GGA. as the unit was on in sync condense mode. GGB was also windmilling at the same time. Requested complete outage on unit to enable work on GGA. Outage delayed due to problems at HRD. GGA lower deflector ring was replaced on 2006-11-18 and and bolts were tapped and retorqued on upper ring on 2006-11-19. GGA upper ring would have failed if retorquing had not been done.

2006-11-22
HWD GT GGA Exhaust Stack Cracks
Inspection identified cracks in the exhaust stacks on GGA at HWD. The problem is referred to engineering and repairs will be included with other structural repairs associated with the RTV coating job in 2007.

2006-11-28
HWD GT AVR Problems (Wayne's Report)
Called in Nov 28. AVR problems; Unit was on generation 40.78 MW 20.49 MVARS. On the AVR we had "Warning" Prot. Rectifier O C
I guess we were up to the limits on the AVR. on the way its set up, or we may need to get ABB back and make further adjustments. On the computer for unit we had AVR fault, diode failure alarms. ECC just had general alarm. Once the load was dropped a little I managed to reset AVR alarms.
Called in Nov 29. GGA on generation, ECC required GGB for generation. Tried GGB several times, kept tripping on in-complete sequence, flame failure. Called G. Lyver for mechanic & technican. When Mike & Leon arrived on site, we gave GGB a dry water wash to make sure no fuel left in engine, Tried ignitors, stroked fuel valve to make sure it was working. Tried GGB again still getting incomplete sequence alarms.
After lunch ECC took unit GGA of generation, and put unit on sync cond. We then decided to try GGA for comparsion purposes with GGB. We then got govenor pressure low alarm, and fuel forwarding system trouble alarms. Now both GGA & GGB are down. Unit on sync cond.
In checking out the fuel system alarm we discovered the differential across the filters in the fuel forward pumphouse was up to 15 PSI. We also discovered
the motorized fuel valve up by the main fuel tank was stuck 1/2 way between opened and closed. We operated the valve in manual several times and managed to free it. It then went to the correct position, closed. thus

eliminating
the fuel system alarms.
Tried GGB, managed to get it up for the supper peak period as requested by ECC.
After unit was put back on sync cond we changed the fuel filters in the fuel forwarding
pumphouse. Since Nov 10, we have consumed 250000 liters of fuel.
When ECC let us have unit down completely we changed the filter on the fuel valve for
GGA. We need the unit completely down for this. This process allowed us to correct the
problem with govenor low pressure alarm on GGA..
We them ran GGA up to 5 MW, no alarms, Ran GGB up no alarms, then we put unit back in
Supervisory both ends available.

2007-01-07
HWD GGA Vibration Trip
Generator vibration when started with GGA.
Note from Hughie to Engineering
I would like for you guys to investigate this vibration problem at Hardwoods as noted below. In a discussion with Wayne Snow he informed me that ECC tried to start End A to put unit on synch condense but it tripped on vibration. Wayne was called out and he asked ECC to start using End B and the unit went on without a problem. He then had end A started and placed on generation mode without a problem. He also indicated that later after the event, end A was used to place Hardwoods on the system in synch condense without incident. According to Wayne this is not the first time this has occurred and it appears to occur at times when an engine is sitting idle for some time.
Could you guys have an engineer from each of your groups (preferably Nelson and Craig) assigned to investigate this to determine if this is a true vibration problem or a problem with the monitoring equipment.
Also with respect to the monitoring equipment we know we are having a problem with spare parts and Craig had prepared an estimate and we would like for you guys to expedite the development of the unbudgeted Capital Job to have the vibration equipment replaced at both sites (HWD and SVL).

2007-02-13
HWD GT Fuel leak into sump.
On Tuesday, Feb 13 it was discovered that fuel was leaking into the sump. Source of the leak was a failed auto-drain and pilot drain valve associated with the oil water separator filter in the fuel line wher the fuel exits the fuel forwarding building to the units. New valve and associated parts are on order and the auto-drain valve is temporairly closed with a manual valve. Amount of fuel lost to the sump was 75 cm rise (638 liters) (sump size is 86 cm X 99 cm). This event resulted in generation being unavailable from Tuesday, Feb.13 to late Thursday, Feb.15.

2007-02-08 / 09
HWDGT
Failed starts were experienced on both GGA and GGB. It was identified the fuel recirc heater was tripping and also the liquid fuel valve start position has to be adjusted. Weather at the time was extremely cold (-20 deg C).
Also identified a problem with the air solenoid for End A snow doors , END A was not available for starting for synch condense or for generate until a new valve is installed . The valve will be flown in overnight and will be installed on the unit in the morning. The unit is expected to be back to full availability by lunch time.

2007-03-14
HWD GT
GGB snow doors failed to operate. air lines to snow doors on GGB found

deterioriated and it is scheduled to replace braided air lines on both GGA and GGB snow doors.

2007-03-15
HWDGT
Investigation of sump at HWD identified the fluid being collected in the sump is fuel. Sump was pumped on Monday, March 12 at 1500 hrs. When dipped on Thursday, March 15, 30 cm of fuel had collected. Investigation on Thursday evening identified the source of fuel release was a failed pressure relief valve in the out line of the fuel re-circ heater. Relief valve to be replaced on Friday morning, 2007-03-16.

2007-03-20
HWDGT
Three failed starts due to incomplete sequence and failed ignition.

2007-02-22
HWDGT
Failed start. Exhaust door trip due to ice on limit switch.

2007-03-26
HWDGT
GGB failed start due to failed ignition.

2007-04-02
HWDGT
ECC ran up unit to 47 MW this morning, then , we got atrbfjbhi alarm.
(Turbine A front
Journal brg high temp alarm). It registered 104 degrees C.
The same brg on B end was low seventies.
Temperature testing done on 2007-04-04. Temperatures were OK until we reached 20 MW's, then it went snakey. Unit tripped at 23 MW's. Will have trends for you tomorrow. Steve and I suggested to limit load to 20 MW until further investigation is carried out. Informed ECC of situation.

2007-04-04
HWDGT
Station inspection identified a deflector ring ahd been ejected from the Gas Turbine End B. Outage was scheduled for 2007-04-05 and inspection found the bottom ring on GGB was missing. Ring was replaced with new and at the same time the upper half was inspected . Bolts were found loose on the upper half as well. Outage sdheduled for 2007-04-13 to inspect deflector ring on GGA. Outcome will determine if SVL requires inspection as well.

2007-04-07
SVLGT
GGB was given a start and when run speed was reached a vibration alarm became active on the exciter. Alarm reset and unit continued to operate in sync condense. The accelerometer for this sensing point was replaced Feb. 7, 2007 when vibration testing was performed and the unit output was low. On 2007-04-09 the accelerometer was switched with the clutch unit in the same vicinity and the vibration followed to the clutch. Awaiting on anothere new accelerometer from HWD to confirm suspicions.

2007-04-09
HWDGT
Failed start on GGB. Attempted a start on GGA and experienced GEN Vibration alarm which operated several times before load was increased and at which point it reset. Vibration testing was completed last week and Bob Stoyles will forward information to Engineering.

2007-04-20
SVL Exciter Vibration Alarm
Replaced accelerometer on exciter and alarm still active on exciter when GGB starts and is engaged. Will arange for shaker table to test new accelerometer to confirm it is working properly. Engineering is aware of

the situation and reviewing setting as well as a solution.
ECC notified to restrict use of GGB until problem is rectified.
Testing was performed on the new accelerometer on 2007-05-03 indicates calibration is correct.

2007-04-23
HWD GT
At 1537:58 hrs GGA was started to put unit on line in sync condense. Vibration alarms were experienced at that time. There was a no vibration alarm meaning the vibration equipment was not sensing any minimal vibration. Also saw vibration alarms on exciter and Gen side A and side B. Unit will be started on 2007-04-24 and vibration will be checked at that time.

2007-05-04
HWD GT
Inspection of deflector rings on GGA identified both top and bottom rings are completely gone with some material remaining in the bottom of the exhaust stack. Also noted that some bolts were found with the retaining wire still intact and the bolt threads in perfect condition. Talked with Robert Shandera and he will attempt to vist site with Nelson Seymour to asses situation. Also noted the bearing experiencing high temperature is located in the vicinity of the failed deflector rings.
The new deflector rings were installed be drilling and tapping all new hole and was completed on May 6 at 2200 hrs. During the outage the thermocouple was checked and cleaned as well as repairs to the wires and marr connectors removed and the correct connectors installed. It was noted the wires were damaged in such a way that there could have been partial grounds on the cables during operation. At 2300 hours on 2007-05-06 GGB was test run to 100% fuel valve for a maximum output of 24.36 MW and the front journal bearing temp was 40 deg C while the rear journal bearing reached 85.5 deg C. These temperatures are consistant with the historical data and the trend data indicated a smooth rate of rise.

2007-05-10
SVL GGA
Unit failed to start due to air regulator problems in the air starter circuit. Main regulator replaced and repairs made to other regulator and valves. Regulators not working correctly due to internal parts sticking.

2007-05-30
HWD GT
Alba Power at HWD to perform inspection of GGA and GGB.Below is Nelson's notes from inspection.

HWD GGA

May 30, 2007	Alba Power did boroscope inspection of LP and HP compressor blades, cans and turbine blades. Said they normally ultrasonic clean burners after boroscope. We opted not to clean burners at the time because we were not having any temp problems. All looked OK except 2 turbine blades had a chunk of meal missing. These blades can be individually replaced but is a factory job. Alba will confirm with report.
May 31, 2007	Reg replaced burners and did load test. Tripped on high EGT at 1.5 MW at 8:00 pm.
June 1, 2007	Test ran engine again with Alba Power on site. Tripped again at about 1.5 MW due to high EGT. All individual temps looked good except thermocouple no. 7 which was very high and causing the excessive spread deviation. Removed and inspected thermocouple. Looked fine. Swapped thermocouples no. 7 and 8 and test ran engine. Tripped again at 1.5 MW. All thermocouple temps looked fine except no. 8 which was very high and causing problem. Replaced with spare unit and test run again. No. 7 thermocouple remained excessively hot.

	Decided to remove no. 8 burner, clean and reinstall. No.7 thermocouple reads the hot gas from no. 8 burner. Noticed a long crack in the bellows between the engine and the power turbine. Needs to be repaired/replaced. We have a spare in stock.

HWD GGB

May 30, 2007	Alba did boroscope inspection of LP & HP compressor blades, cans and turbine blades. A spacer piece is missing from the HP compressor blades and a also another component appears out of place (spring component that helps secure blades in place).Condition of compressor blades and cans looked O.K. Turbine blades showed some discoloration which appeared to be from improper flame pattern. Alba recommended checking the fuel distributor. Also suggested putting a gauge on both the primary and secondary fuel supply hoses to a burner to measure pressure. They know what it should be. Alba recommended nobody enter the engine compartment while the unit is running until the spacer issue is resolved. HP compressor blade spacers should be able to be replaced on site. Alba to confirm in report. The large band clamp connecting the air intake cone o the LP compressor was loose and a separation had occurred. Reg repaired.
May 31, 2007	Reg reinstalled burners and did a load test. Results same as before. Went into alarm at about 22.5 MW.

When burmers were re-installed in GGA, high temperatures ere experienced. All burners were removed and ultrasonically cleaned. At 2041 hrs on 2007-06-02 GGA was run to 24.2 MW, fuel valve opened 100%, and spread was 28.6 degrees C.

2007-06-06/07
SVL GT
Alba Power on site to perform boroscope inspection of GGA and GGB through the removed fuel nozzles and also through the air intake at both ends.

2007-06-09
SVL GT
Generator high temperature alarm experienced while the unit was online in sync condense mode. To enable investigation the emeregency air doors for the generator were opened so the generator glycol cooler could be shut down. As of 2007-06-26 work to determine cause of heating includes:
1) Testing air flow through rad fins. Ongoing.
2) Testing glycol flow through piping system. Ongoing.
3) Breakdown and inspection of 3-way mixing valve. Valve requires replacement due to scouring and controls not functioning but indications are it is not the cause of generator high temperature.
4) Check and adjust pitch on cooler fan blades. Adjustment required and further repairs required to a blade.
5) Identified paint overspray on fan blades and cooling rad fins. Effects to be determined.
6) Identified sand blastings silica accumulated inareas between the rad cooling fins. Cooling ongoing and effects to be determined.
7) Identified severe rusting of support beams and structure of cooler

housing. Engineering to investigate and determine a solution as well as determine if it has any effect on the cooling problem.
Overall investigation is continuing to determine the specific cooling issue or if it is a combination of several accumulated problems.

2007-06-29
SVL GT
MLO Cooler
Operator identified cracks in welding that attaches the rad fan and blade assemblies to the cooler housing. Request engineering to assess both coolers for structrual integerity.

SVL Gas Turbine Work Order History

Date	Event	Details
8/11/2006	Anti -Ice Valve GGB	Removed and shipped to HWD, HWD GGA failed
7/5/2006	Compressor A Failure	New piston rings, seals and gaskets
4/27/2006	GGB Burners EGT	Removed and sent to Rolls Royce for inspection
3/30/2006	GGB Burners EGT	Installed burners in GGB that were removed from HWD GGB
3/27/2006	Compressor A Failure	Replaced damaged box cable
3/21/2006	Compressor A Failure	Replace flexible air line
3/21/2006	Compressor B Failure	Replace flexible air line
3/16/2006	SVL GT Trip	Logic for EGT modified
3/10/2006	Access Doors	Enlarge access covers on GGA & GGB
3/10/2006	Lube oil pump Fail	Replace bearing
3/6/2006	EGT alarm GGB	Modify logic
2/28/2006	Failed start GGA	Adjusted fuel transducer
2/23/2006	GGA loading	replace fuel strainers anf filters
2/22/2006	Failed Control display	Replaced monitor
2/7/2006	GGA GGB EGT Spread	Modified fuel flow logic
2/2/2006	GGB Combustor Cans EGT	replaced with overhauled cans (8)
1/25/2006	Fuel Meter Fail	Meter replaced
1/18/2006	GGB EGT Spread	Remove / test thermocouples
1/15/2006	GGA GGB EGT	Inspection by Rolls Wood
1/15/2006	GGB EGT Spread	replace strainer and banjo assemblies
11/2/2005	Air leak	Replace gasket on receiver
10/27/2005	GGB EGT Spread	Cleaned burners
10/27/2005	Gen Fail	Check exciter straps
10/3/2005	GGA GGB EGT	Logic revised
8/4/2005	GGA Sync Fail	Adjusted fuel valve
7/15/2005	Printer fail	Replace cable
6/2/2005	Gen alarm	???
4/21/2005	GGB Fuel Actuator	Install Heat tracing
4/13/2005	Air receiver A & B	Replace pressure relief valve
4/12/2005	Air receiver A	Replace failed pipe
4/7/2005	Lube Oil Sys failure	replace pressure switch
3/21/2005	Compressor A Failure	Replace gaskets and rings
3/11/2005	Gen Exciter trouble	repair exciter metering
3/10/2005	Compressor B Failure	replaced after cooler
3/2/2005	GGB failed to start	
2/28/2005	Air dryer leak	new filters and clean valve
2/21/2005	Inlet plenium B	Repair holes in floor
2/21/2005	Fuel sys	replace transducers for overfill protection
2/3/2005	Printer fail	configer printer
1/26/2005	cooling sys modify	add conditioner
1/20/2005	GGA & GGB	repair cracks in exhaust stacks and enclosures
1/19/2005	GGB failed	fan motor repaired
1/12/2005	Sump System	Modify logic
12/22/2004	Lube Oil Sys failure	exchanger cooling fan belts
10/8/2004	GGB Exhaust leak	repairs to turbine casing flange joint
10/29/2004	Fuel forwarding trouble	
10/28/2004	GGA trip on high temp	
10/28/2004	GGA Exhaust gas leaks	Retorqued bolts
10/28/2004	GGA & GGB hot end inspection	Also cleaned fuel nozzles
10/13/2004	GGB high temp alarm	
10/8/2004	Unit controls fail	Repairs to cards in DCS
9/9/2004	240 v battery	replaced cell
8/12/2004	Compressor A Failure	repair oil leak
7/22/2004	GGB failed to Sync	
7/22/2004	Jct Box JB7B corrodion	install heater
7/15/2004	Paint rusted fuel tanks	
6/18/2004	GGA combustion chamber drain valve	
6/17/2004	GGB combustion chamber drain valve	
6/4/2004	GGA & GGB Heaters fail	repair heater connections
6/3/2004	Battery room heater installed	
4/20/2004	Compressor A Failure	replace gaskets and oil
4/15/2004	Lube Oil Sys failure	Replace heater circuit breaker
3/16/2004	Gen Fail	inverter failed and replaced
3/4/2004	GGA & GGB start fail	fuel heating repairs
2/24/2004	GGB Sync Fail	
2/23/2004	GGA Failed start	Fuel valve adjusted
2/18/2004	Printer failed	Changed settings
2/11/2004	Air dryer fail	modified output line and check valve
1/27/2004	GGA Failed start	

1/20/2004	Annunciator fail	replaced cards
12/17/2003	AVR Floor Repaired	
12/11/2003	GGA & GGB logic changes	
12/10/2003	Lube Oil Sys failure	reset logic
10/24/2003	250 v battery bank replaced	
10/17/2003	GGB Exhaust leak	Retorqued bolts
10/10/2003	Fuel sys leak	leaking filter
10/7/2003	Generator cooler fail	belt replaced
9/30/2003	GGA Failed start	adjusted fuel transducer
8/28/2003	Compressor A Failure	Head gasket
8/13/2003	Fuel sys leak	
7/2/2003	GGB failed sync	fuel valve problem
6/27/2003	Motor contactors fail	required cleaning
6/18/2003	Compressor B Failure	replace aftercooler
6/17/2003	Generator AVR repairs	
5/14/2003	GGA & GGB Inlet filter diff fail	replaced tubing and repaired switch
4/30/2003	GGB Temp Trouble	Replaced thermocouple wire
4/6/2003	Air dryer fail	Replaced check valve
2/6/2003	Unit metering fail	repairs to KWH meter
2/4/2003	GGA EGT fail	repairs to fuel pressure transducer
1/28/2003	Air dryer fail	replaced filters
1/15/2003	lube oil sys alarm	lube oil added
11/1/2002	lube oil cooler housing	repairs to screen and frams
10/16/2003	GT fuel leak	repairs to fuel valve
10/10/2002	lube oil leak	repairs to tregulator flange
5/31/2002	GGB Failed to start	Repair to oil pressure switch
5/9/2002	Install thermal assembly on fuel temp regulator	
4/30/2002	Main Fuel valve leak	replace gasket
4/30/2002	GGA & GGB EGT alarm	Logic changes
4/16/2002	Fuel level fail	Transmitter fail
4/4/2002	GT unavailable	TRF SS1 high temp alarm
3/15/2002	GT Control fail	Switch replaced
3/5/2002	Clutch fail	Solenoid checked
2/4/2002	Fuel metering fail	Calibrate meter
12/12/2001	GGA fuel valve repair	
12/7/2001	GGB fuel valve repair	
8/24/2001	Inlet plenium A paint	
7/6/2001	Fuel tank farm	install expansion tank
1/23/2001	Exhaust A replace volute fabric	
1/17/2001	GGA & GGB Control logic adjustments	
1/12/2001	GGB sent to Rolls Wood for repairs	
1/10/2001	GGB Inlet plenum broken hinges	
1/9/2001	GGB Actuator oil leak repaired	
12/8/2000	Compressor A Failure	new gaskets and rings
11/22/2000	GGB Exhaust gas bellows replaced	
11/7/2000	Mube oil sys fail	replaced timer
9/22/2000	GGA Exhaust gas bellows replace	
8/9/2000	GGB Actuator repair	
6/28/2000	Generator fail	Bushing replaced
5/18/2000	cooling sys fail	repair glycol pump
5/18/2000	GGA & GGB hot end inspection	With Rolls Royce rep. On site
4/27/2000	Compressor B Failure	new gaskets and rings
3/13/2000	Generator alarm	Heater fail
3/9/2000	Clutch A fail	locking solenoid fail
1/6/2000	Clutch A & B Heaters not working	
12/20/1999	Fuel off loading	repair start button
11/3/1999	Exhaust A replace volute fabric	
9/10/1999	Low volts DC alarm	
9/2/1999	Inlet plenum floor paint	
9/1/1999	GGB removed and shipped to HWD	
8/16/1999	Cooling sys motor overhauled	
3/24/1999	Datalogger fail	
1/1/1900	Cooling sys leak	Replace pump seals
3/30/2001	GGA damaged burner	replaced
7/24/2001	Fuel tanks	Installed level transmitters on all tanks
9/15/2006	GGA & GGB Repair and paint structure	

SVL Gas Turbine Station Log History

Date	Event	Details
1/20/1992	GGA & GGB Sync Fail	Speed control problems
2/26/1992	GGB Sync Fail	Governor Problems
2/28/1992	GGB Sync Fail	Clutch problem
3/10/1992	GGB Sync Fail	Control card
4/27/1992	GGA Shut	Fuel filter leak
6/8/1992	GGB LP Compressor vanes removed	To Roll Royce for repairs
8/31/1992	Unit Tripped	Low oil pressure
9/21/1992	Unit shut	Replace Tacometers & repair snow door electrics
9/22/1992	GGB lube oil pressure	replace switch
12/10/1992	Failed to sync	Governor Problems
3/31/1993	GGA Inspection	Performed by Rolls Royce
4/1/1993	GGB Inspection	Found 3 can straps starting to burn
5/12/1993	Gen trip	Unit lockout and reverse power
7/26/1993	Gen trip	Component failures in control cct, vibration monitor & governor
7/30/1993	GGA & GGB Unavailable	Air supply problems and control component failures
8/5/1993	Gen removed from service	Failed lightning arresters and bus
8/9/1993	GGA Fail	Vibration monitor problem
8/10/1993	GGA & GGB	Vibration monitor problem
8/17/1993	GGA & GGB Loading problems	Woodward rep on site to look at load sharing
8/23/1993	Gen out of service	Jacking pump failure
5/30/1993	GGB Alarm	Low fuel pressure
10/6/1993	Sync Cond trip	AVR undervoltage, blown fuse
10/13/1993	GGA Unavailable	Air starter regulator repairs
10/20/1993	Generator removed from service	DC ground problem
10/22/1993	GGA fail	ignition problem
11/4/1993	GGA Removed from service	replace ignitor
12/16/1993	GGB Fail to start	Governor Problems
12/25/1993	Generator trip	Fault on 138 kv bus returned to service 1994-02-23
1/7/1994	G1T1 repairs	Sent to manufacturer for repairs
3/12/1994	GGA Failed start	Snow door problem
3/28/1994	GGA Failed start	Nnknown reason
3/29/1994	GGB removed from service	Replace thermocouple
4/3/1994	GGB removed from service	Lube oil filter blocked
5/31/1994	GGB failure	Ait starter leak
7/2/1994	GGA Failed start	Peroblem with exhaust doors
7/5/1994	Sync Condense trip	Control relay failure
7/6/1994	GGB removed from service	Air supply leak
7/14/1994	GGA Failed start	Incomplete sequence
7/27/1994	GGA failed to sync	Unit breaker racking problem
8/13/1994	GGA failed to sync	Sync PT problem
10/30/1994	Generator trip	PT failure
11/22/1994	Bus duct support insulators replaced	
12/11/1994	GGB failed sync	Clutch proximity switch fail
1/5/1995	Sync Condense failure to select	Problem unknown
1/13/1995	GGA Failed start	Snow door alarm
2/14/1995	GGB failed start	Air starter failure
5/30/1995	GGA Failed start	relay failure
8/23/1995	GGB removed from service	Replace engine oil due to lab analysis
9/11/1995	GGA New air filters system	8 days
1995-19-27	GGA New air filters system	8 days
10/11/1995	Gen unavailable	Faulty datalogger
19995-10-12	Generator unavailable	AVR failure
10/23/1995	Replaced unit MVAR meter	
12/14/1995	Generator unavailable	Woodward rep on site to look at Isoc / Droop loading problems
1/1/1996	GGB failed start	Control relay problems
1/3/1996	GT max load 35 MW	Woodward rep visit site. Found loose connection on A ph PT primary finger contact
1/16/1996	Generator unavailable	Droop load sharing problems. Card replaced in controls
5/31/1996	GGA Removed from service	Repair air starter
7/2/1996	GGB fuel leak	Engine fuel line replaced

9/11/1996	Generator removed from service	Datalogger fail
7/14/1997	GGB failed start	Starter Failure
7/22/1997	GGB failed start	Air regulator problem
9/2/1997	Sync Condense trip	Halon sysatem malfunction
2/20/1998	GGA Removed from service	Snow door problem
5/20/1998	Generator sync fail	Blown fuse
5/23/1998	GGA & GGB Trip	DC breaker trip
7/1/1998	Sync Concense trip	T1 lockout due to Gen bushing failure
8/24/1998	Sync condense trip	Problem with voltage (64B) cct
11/23/1998	Unit shutdown	Install new fuel meter
1/3/1999	Sync Condense trip	High temp due to cooling pump fail
1/19/1999	Unit removed from service	Fuel meter problem
5/25/1999	Unit removed from service	Install new DCS system, returned to service 1999-08-11
10/24/2000	GGB Out of service	Engine in Scotland for repairs since Sept. 7, 2000
10/24/2000	GGB Bellows changed out	Bellows taken from GGB and installed on GGA. Faulty bellows sent to St. John's for repairs.
10/26/2000	Contaminated soil	Contaminated soil removed from tank farm in Sept, 2000.
11/6/2000	Coolant alarms	Glycol fan failure
12/1/2000	Hoist repair	GGA & GGB 5 ton hoist sent to Dover Crane for repair
1/5/2001	GGB returned and inatalled	Returned from Scotland
1/16/2001	GGB EGT spread trip	Tuning and making adjustments with Craig Warren next 2 days
1/17/2001	GGA Clutch problem	Clutch had to be dis-engaged manually by mechanic
1/22/2001	GGA Outage	Replace exhaust fabric
1/23/2001	GGA Burner #4 loose shroud nut	
2/22/2001	Lube oil high temp and low level alarm	oil added
3/8/2001	Unit Tripped	Main lube oil temp / low level alarm
3/30/2001	GGA Burner # 4 replaced	$8,000.00
5/15/2001	Fuel Sys Problems	All three fuel transmitters sent away for calibration
5/28/2001	GGB tripped	EGT trip
5/28/2001	GGA failed start	Incomplete sequence
5/28/2001	GGB tripped	EGT tripped several attempts
5/29/2001	GGB start fail	Fuel transducer
6/7/2001	GGB failed start	ignition problem
6/8/2001	GGB Fuel transducer adjusted	
9/19/2001	GGA Low fuel pressure alarm	Filters replaced
11/5/2001	GGA Alarms	Temp alarms in Turbine BRG, Lube oil and Gas Gen Enclosure
11/29/2001	GGA Trip	Speed sensor fail
12/4/2001	GGB failed start	Solenoid burnt out
12/4/2001	Sync Condense trip	Glycol pump fuse blown
12/4/2001	GGA Clutch fail	Mechanic had to disengage manually.
12/5/2001	GGB failed start	Liquid fuel valve position fail
1/10/2002	New Energen system in service	
1/31/2002	Generator trip	Reverse power
2/22/2002	GGB failed start	Low DC volts alsrm
2/27/2002	GGA Temp alarm	Failed thermocouples
3/5/2002	GGA Clutch solenoid replaced	
3/5/2002	GGA Failed start	Low fuel pressure. Filter replaced
3/5/2002	Main lube oil temp alarm	Failed regulating valve
3/15/2002	ECC unable to select sync condense to generate mode	Logic problem
4/4/2002	SS1 High Temp Alarm	RTD connections failed
4/20/2002	GGB tripped	Lube oil pressure switch fail
4/30/2002	GGB Logic changes made by Engineering	
5/7/2002	Fuel leak	Fuel filter o-ring replaced
5/30/2002	GGB failed start	Failed lube oil pressure switch
9/18/2002	Fire dampers on GGA & GGB replaced	
10/16/2002	GGB Fuel valve fail	Faulty microswitch
10/24/2002	Alarm, Unit not ready	Air system failure
11/2/2002	Generator trip	Reverse power
11/15/2002	Sync Condense trip	Main lube oil pump leak
11/26/2002	Air dryer fail	Broken prefilter
11/29/2002	GGB not operational until GGB oil is changed	

1/27/2003	Alternator cooling problem	Fan motor failure
1/28/2003	Dryer assembly replaced	
1/29/2003	GGA, GGB and alternator not available	Main lube oil alarm. Faulty relay in heater
1/30/2003	GGA EGT trip	
1/31/2003	GGA trip	Fuel pressure switch failure
2/14/2003	GGB trip	Exhaust door failure
2/14/2003	GGB Fail to start	Hydraulic actuator malfunction
3/14/2003	Fire impairment	Water supply from town frozen, restored 4/28/2003
3/27/2003	250V battery trouble	Cell #14 & 56 removed
4/7/2003	Unit control problems	Monitor and keyboard failure, returned to service 5/14/2003
4/21/2003	GGB trip	Reverse power
4/25/2003	GGA failed start	
4/30/2003	GGA failed start	
6/18/2003	MCC contactors trouble	Required cleaning
6/29/2003	GGB failed start	Auto sync trouble
6/29/2003	GGB failed start	EGT high
6/30/2003	GGB failed start	Fuel transducer adjusted
8/22/2003	GGB EGT trip	
9/18/2003	GGA EGT trip	
9/30/2003	GGA failed start	Fuel transducer problem
10/6/2003	Cooling system failed	Fan motor belts replaced
10/15/2003	Gas generator	Retorqued flange bolts on power turbine casing
10/24/2003	250V battery bank replaced	
11/9/2003	GGB trip	Enclosure high temp
11/9/2003	GGA failed start	Three times on EGT
12/2/2003	GGA & GGB failed start	Jacking pump blown fuse
12/27/2003	Control system failure	Inverter failure
1/1/2004	Air system failed	Dryer after filter housing failed
1/5/2004	Control system failure	Inverter failure. Removed from service
1/7/2004	Logic changes	Generate/sync condense mode
1/7/2004	GGA failed start	Light off problems. Fuel transducer adjusted
1/7/2004	GGB snow doors failed to close	Operating pressure adjusted
2/2/2004	GGB failed sync	Control problems
2/16/2004	GGA failed start	Failure to light off
2/18/2004	Printer replaced	
2/22/2004	Main lube oil temp alarm	Heater breaker tripped
2/25/2004	Fire relay for glycol pump replaced	
3/4/2004	Fuel re-circ heater returned to service	
3/12/2004	New inverter in service	
3/19/2004	Fuel re-circ heater logic changes	To prevent heater from staying on if unit trips
4/19/2004	Lube oil pressure alarm	Filters replaced
4/28/2004	GGA & GGB power turbine	Retorqued flange bolts
5/18/2004	GGB hot end inspection	
5/19/2004	GGA hot end inspection	
6/14/2004	All three fuel tanks painted	
7/16/2004	125V battery bank removed from service	Thermal runaway on VRLA
9/27/2004	Generator trip	Alternator main lube oil temp. Fan failure
9/28/2004	GGA EGT trip	
9/30/2004	GGA failed start	High EGT
10/2/2004	GGB shutdown	Auto sync trouble
10/8/2004	DCS logic changes	
10/13/2004	GGB EGT trip	Fuel actuator adjusted
10/13/2004	GGA clutch failure	Proximity switch fail
10/18/2004	GGB failed start	Fuel transducer
10/21/2004	New 125V battery bank in service	
12/7/2004	GGA trip	Liquid fuel failure
12/7/2004	GGB EGT trip	
12/7/2004	GGA failed to light off	
12/7/2004	Generator trip	Reverse power
12/13/2004	GGA failed start	
12/13/2004	Main lube oil failure	Relay failure
1/12/2005	Sump level logic modified	
1/13/2005	Computer repairs	New power supply fan

1/19/2005	GGB enclosure fan motor replaced	
1/20/2005	GGA GGB exhaust stack repairs	Cracks repaired
2/22/2005	GGB failed start	Generator overspeed trip. Actuator adjusted
2/23/2005	Generator trip	High bearing temperature. Blown fuse
2/23/2005	GGB EGT trip	
2/23/2005	GGA EGT trip	
3/8/2005	Main lube oil control relay failure	
3/9/2005	Compressor #2 fail	After-cooler replaced
3/14/2005	Air receiver tank #1 severe leak	Tank isolated and removed from service and repaired by contractor
6/2/2005	Sync condense trip	DC ground
6/23/2005	Start sight assessment for hydrocarbons	
8/3/2005	GGB failed start	Exhaust thermocouple quality
8/3/2005	GGA failed start	Sync trouble
9/2/2005	Generator trip	Reverse power
9/2/2005	GGB EGT trip	
9/15/2003	GGB failed start	High EGT
10/3/2005	Control logic changes	
10/25/2005	Generator excitor failure	Blown fuses. Failed excitor straps
10/27/2005	GGB EGT trip	Burners #1 & 4 cleaned with no success
10/27/2005	GGA failed start	Liquid fuel valve position fail
10/28/2005	Fuel transducer adjusted	
11/2/2005	GGA air starter leak repaired	
11/14/2005	GGA hot end inspection	Engineering and Rolls Royce on site
11/15/2005	GGB hot end inspection	Engineering and Rolls Royce on site
11/21/2005	Fuel meter replaced	
11/23/2005	GGA failed start	EGT spread
11/26/2005	GGB failed start	Failed to light off
12/1/2005	GGA & GGB logic changes	
12/2/2005	GGA failed start	EGT spread
12/16/2005	Emergency diesel installed	
1/3/2006	Cooling failure	Main lube oil temp. Belts replaced
1/16/2006	GGA failed start	EGT
1/19/2006	GGB fuel nozzles removed and sent to the UK for overhaul	
1/23/2006	GGA failed start	Adjusted fuel transducer
1/24/2006	GGA failed start	EGT spread
1/25/2006	GGA sync condense	Three attempts before success
1/30/2006	GGB combustor cans	GGB combustors cans replaced with refurbished set stored at HWD. Rolls Royce rep on site
2/2/2006	GGA failed start	EGT spread
2/5/2006	GGA failed start	EGT spread
2/6/2006	GGA failed start	EGT spread
2/6/2006	GGA fuel trandsucer adjusted twice	
2/7/2006	GGA logic	Engineering on site for logic changes
3/6/2006	GGB logic changes	
3/16/2006	GGA logic changes	
4/5/2006	Anti-ice valve returned to GGB from HWD	Fuel nozzles from HWD GGB installed in SVL GGB. Three attempts to light off GGB failed. Fuel transducer adjusted
4/25/2006	Snow doors repaired	
6/9/2006	Compressor #1	New rings
6/15/2006	Replaced voltage snubbers in control circuit	
8/8/2006	GGB unavailable	Combustor cans, fuel nozzles removed from SVL GGB and sent to HWD GGB. Anti-ice valve removed from SVL GGB sent to HWD GGA
8/17/2006	GGA failed start	EGT. Three attempts. Fuel transducer adjusted

Hardwoods Gas Turbine Work Order History

Date	Work Performed
21-Aug-06	Installed combustion cans (under supervision of Rolls Royce Rep Alain Joseph) from SVL END B in HWD END B EGT alarm at 22MW
19-Aug-06	L/P Turbine Inspection completed by Steve Press of Rolls Wood .Everything looked good..
8-Aug-06	Exhaust stack noise reduction panels repaired. Bolts rusted off. Black and Mac performed temporary repairs. Permanment repairs scheduled for fall.
4-Aug-06	Attepted to repair leak on demister
31-Jul-06	HWDGT END A tripped following logic changes due to anti ice valve problem pulling down voltage to P/S. Anti ice valve from SVL END B installed at HWD End A.
17-Jul-06	DC ground fuel valve. Replaced corroded junction box.
7-Jul-06	Repaired drainage sump piping due to heaving from frost.
4-Jul-06	Replaced proximity switch GGA clutch.
14-Jun-06	Changed snubbers (9) in junction box for fuel system GGA & B.
14-Jun-06	Rewired anti ice power supply to increase capacity due to ongoing intermittent P/S loading down problem.
5-Jun-06	HWDGT call out - clutch problem.
1-Jun-06	Fuel leak - Replaced Jordan valve
29-May-06	Repair air dryer - Replaced Hex Air Valve
26-May-06	Repair fuel leak - Replace o-ring on filter GGA
24-May-06	HWDGT, repair leak stand by diesel unit. Replace valve cover gaskets.
23-May-06	Repair lube oil leak on vacuum pump. Replaced line from vacuum pump to demister.
9-May-06	Replace anti ice P/S as a result of a callout on May 7, 2006 due to low voltage on P/S. Calibrated spare P/S and installed.
28-Apr-06	Repaired leaks on MLO System.
24-Apr-06	Replaced bearing and shaft on #1 fan for Glycol cooling system.
19-Apr-06	HWDGT, End B swapped burners 2 & 5 and EGT alarm at 19 MW.
3-Apr-06	Repair demister leak. Replace filter gaskets and housings.
3-Apr-06	Changed solenoid GGA/GGB lube oil system.
30-Mar-06	Installed repaired anti ice valve from OZARK and shipped SVL unit back.
30-Mar-06	Replace 30A, 600V breaker for Gycol system.
24-Mar-06	HWDGT, replace burners GGB (removed burners that were installed March 6, 2006)
22-Mar-06	HWDGT, check P/S to clutch solenoid. Found problem with snubber circuit. Repair clutch on END A OK.
21-Mar-06	GGA, replace Jordan valve.
21-Mar-06	Competed adding 20 drums of TRESSO 32 bearing oil due to sump alarm on March 19. The source of this leak was the expansion joint on rear journal bearing on Turbine A. All expansion joints at HWD and SVL were inspected and tightened as required.
19-Mar-06	Investigate sump alarm at HWDGT.

15-Mar-06	Reinstall anti ice valve from SVL and send anit ice valve back to OZART for repairs.
14-Mar-06	Replaced inverter.
14-Mar-06	Replace cable to fuel filter alarm.
14-Mar-06	Replace safety relief valve on comp "B".
6-Mar-06	Snow doors END B - replaced regulator and solenoid, 3 brackets and clamps.
6-Mar-06	HWDGT, replace burners. Installed refurbished burners in END B and sent old back to SVL.
1-Mar-06	GGA, clutch malfunction. Removed covers and unlocked clutch.
28-Feb-06	HWDGT, high press on fuel forward pump. Replace and relocate thermocouple.
28-Feb-06	Changed final fuel filter on GGA.
23-Feb-06	HWDGT, Glycol S,s #1 fan noisy. Grease bearing housing.
18-Feb-06	Replace Glycol fan belts (2 of 3)
14-Feb-06	Stand by diesel. Replaced AVR, speed pot, replaced actuator cable.
14-Feb-06	Repaired oil leak on demister.
9-Feb-06	Stand by diesel prot trip.
9-Feb-06	HWDGT, repair flow meter error message.
27-Jan-06	Install anti ice from SVL B on HWD End A.
27-Jan-06	Tested manually operation of END A and END B to determine if one end could take 25MW and other 15MW. Failed; Denoted SWDGT to 2 X 15MW = 30MW.
27-Jan-06	Fabricate 2 Jboxes, to prevent water from entering due to snubber circuit failures.
21-Jan-06	**See Jims email for detail.**
20-Jan-06	Snow Doors, repair solenoid.
18-Jan-06	Calibrate fuel meter.
12-Jan-06	Replace Jordan valve.
10-Jan-06	Checked Thermocouples on END B (to ensure exhaust gas temp are "real".
20-Dec-05	GGB replace Jordan valve.
16-Dec-05	Pumped out 240 gallons of fuel. Replaced 3 pressure relief valves in fuel forwarding system.
28-Nov-05	Repaired broken line on snow doors.
18-Nov-05	Installed flow meter. HWDGT GGB Hot End Inspection.
17-Nov-05	HWDGT, GGB invest hot burner.
17-Nov-05	Inspection of HWDGT and SVLGT by Rools Wood/ABB Rep to help with EGT problem.
15-Nov-05	Installed new 125 VDC bank.
14-Nov-05	Replaced standby diesel unit
14-Nov-05	Replaced bottom bearings on both fans.
14-Nov-05	Replace dirty alternator filters.
10-Nov-05	Failed to start. Relay burned up for starting Demister .Replaced relay "OK"
8-Nov-05	Replace burnt vib cards.
27-Oct-05	Replace rusty conduit.
19-Sep-05	HWDGT, fuel module leak/repair.
19-Sep-05	HWDGT, END B temp test.
16-Sep-05	HWDGT, END A replaced proximity switch due to clutch malfunction.
15-Sep-05	HWDGT, invest END A clutch. Checked operation, starting and stopping (intermitent problem)
9-Sep-05	Repaired fuel leak on fuel nozzle no. 7.
23-Aug-05	Repaired broken wire on field GND where it attaches to brush, (Alarm).
21-Aug-05	Snow doors, END A repaired air leak.
12-Aug-05	HWDGT, programed logic for motorized fuel valve.
8-Aug-05	HWGT END A, clutch alarm. Replaced proximity switch on END A and ok.
5-Aug-05	Replace sump drain lines.

4-Aug-05	Hot end inspection performed. W/O 385531
3-Aug-05	Upgrade fuel system for stand fuel to connect to sump drainage system.
27-Jul-05	Contractor install new supply and return lines from fuel forwarding BLDG to END A and END B due to a fuel leak discovered on June 9, 2005 during escavation to tie diesel building drainage system into sump system.
28-Jun-05	Snow doors, replace all flex. Line on snow doors. Replace rusted air cannisters and filters.
22-Jun-05	Pressure tested lines and discovered Sup/Ret lines were pitted and leaking
14-Feb-05	Reparred air leak on snow doors.
27-Jan-05	Reparied fuel leak - FF BLDG - Replaced air trap for main fuel filter.
8-Nov-04	HWGT, repaired fuel leak and pressure tested.
14-Sep-04	Call in - Loss of ready lights. Low temp on MLO, reset unit OK.
9-Sep-04	Call out - computer locked up unit at 40MW ECC had alarms but could not be seen locally. Had to re-boot.
27-May-04	HWGT, replaced AVR voltage adjust motor.
16-Apr-04	HWDGT, repair fuel leak.
10-Apr-04	Replace alternator filters.
7-Apr-04	HWDGT, JB-3 replaced term strip and wiring
1-Apr-04	Repaired float switch for sump
12-Mar-04	Glycol cooling system - installed 2 inspections hatches
12-Dec-03	HWDGT would not start due to vibration alarm. Tightened monitoring bolts on vib detec.
5-Nov-03	HWDGT, intermitent GT fire system alarm. (NF Power system problem and when power would go off, alarm would come in.
20-Aug-03	HWDGT GGA, Replace proximity switch clutch A.
18-Aug-03	GGA, installed overhauled burners that were sent to Rolls Wood in June, 2003.
20-Jun-03	Replaced main lube oil heat exchanger.
12-Mar-03	HWDGT END A Problem with EGT at 22MW.
5-Mar-03	GGA perform hot end inspection by R.R. up
9-Dec-02	GGB repaired Jordan valve.
10-Oct-02	Replaced shaft on main fuel pump #1
27-Sep-02	Change logic for EGT trips/alarms as per Craig Warrens request.
19-Sep-02	Repair oil leak on main supply line to main tank (contractor completed HP welding)
19-Apr-02	Repair demister leak.
18-Apr-02	Repair leak on #1 fuel forwarding pump.
10-Jan-02	Repair leak on Jacky pump GGB
19-Dec-01	Replace and repair Jordan valve GGB.
14-Nov-01	GGA, Repair leak on Jordan valve.
29-Oct-01	GGB tripping on single exhaust thermocouple. All thermocouples are reading high on END B.
22-Oct-01	Repair oil leak on demister
18-Oct-01	Repair leak on jacky pump, GGA
18-Oct-01	Replace limit switch on blow in doors.
28-Sep-01	Elect. Switch for sump replaced.
24-Sep-01	Can not control voltage on unit
4-Jun-01	Fuel leak repair fillter housing GGB
15-Mar-01	Check and repair DC GND
9-Mar-01	Trouble MLO - found belts broken on Glycol cooling fan #1
14-Feb-01	Installed new invertor.
25-Dec-00	Starting problems on Xmas Eve and day. Eventually got END B ON.

18-Dec-00	Inverter and DC GND. GND on the A END governor motor. Flex conduit from motor to JB was replaced.
8-Nov-00	Replaced and tapped broken proximity Switch cover and replaced Prox switch due to clutch A problem.
17-Oct-00	Point fuel storage tank.
6-Oct-00	Replaced safety valves on both receivers.
2-Oct-00	Replaced oil seal on MLO pump #1
28-Aug-00	HWDGT, GGA, oil alarm. Adjusted Glycol regulator.
9-Jun-00	Replace mech seal and o-ring on main fuel forwarding pump.
17-May-00	RR Rep complete hot end inspection on A & B
27-Apr-00	Due to vibration problems GGA was sent to Scotland for repairs.
30-Mar-00	Test thermocouples on EGT A & B 200°C, 400°C, 600°C using oven form HRD plant. All temp within 3% of oven settings. HWGT A & B, recalibrate exhaust thermocouples due to END A tripping EGT.
24-Dec-99	Clutch A-Repair
8-Dec-99	HWDGT, repaired thermostat valve on Glycol system
1-Dec-99	HWDGT, GGA fail to start. C. Warren made logic changes due to BRG/ lube temp trip and alarm being reversed.
30-Nov-99	HWDGT, GGA fail to start. C. Warren made logic changes due to BRG/ lube temp trip and alarm being reversed.
30-Sep-99	Replaced air filters.
10-Sep-99	Install GGA that was removed from SVL.
18-Jun-99	HWDGT, AVR/Exciter trouble AVR 1 & 2 tripped due to 400A fuses in exciter. Four of six fuse, had to be replaced.
15-Jun-99	HWDGT, repair demister leak.
15-Jun-99	Change alternator filters.
June 3-8, 1999	Investigate lube oil trip.Raised High temperature alarm, shut down and trip from 75-100, 80-105, 90-115 on A and B. Change filter on GGA and GGB lube system.
21-Apr-99	Investigate sequence failure/ignitor END A. Adjust sequence fail ignitor form 10-12 sec.
8-Mar-99	Call out - Sync cond trouble, alarm on shut down. Alarm reset okay.
28-Feb-99	Auto Sync Trouble - Callout Reset Okay.
20-Feb-99	Callout - Loss of control of Gas Turbine Aux relay in IRD (KS) faulty.
Mar 12 & 14, 1999	Auto sync trouble alarm on start down fo sync condense on March 12 and twice on March 14, 1999, March 23 & 24. After consulting with eng. 1. Sync trouble 2. Auto Sync trouble 3. Stator temp low were disabled to ECC's alarm page.

Hardwoods GAS Turbine Station Log History

Date	Event	Details
1/9/2002	GGB Fuel leak	Fuel pump repairs
1/9/2002	Fuel system trouble	Fuel heater not working
1/11/2002	GGB Fuel leak	Fuel pump repairs
1/18/2002	Air Temp Regulators	Replaced temperature probe
1/24/2002	GGA & GGB failed start	Several attempts Incomplete sequence Failed to light off
1/25/2002	Lube oil problems	Replaced oil gauge on MLO pump # 1
1/29/2002	GGB Trust Bearing Trouble	Thermocouple failed
1/31/2002	GGA & GGB failed start	Incomplete sequence Had to run lube system in manual prior to start to warm oil
2/5/2002	Lube oil problems	Re-circulated oil and governors to maintain temperatures
2/8/2002	GGA & GGB failed start	Incomplete sequence. No flame. Had to run oil and governor pumps for temperature
2/10/2002	Failed to start	Dc ground. Failed control relay.
2002--02-12	Beraings low temp	Circulated oil to warm up.
2/13/2002	Failed start	Incomplete sequence. No flame. Had to run oil and governor pumps for temperature
2/13/2002	DC ground	Failed control relay
2/14/2002	Lube oil problems	Low temperature. Installed heat tracing and pipe insulation.
2/19/2002	Engine expansion joint inspection	
2/19/2002	Compressor # 1 problems	Unloader repairs and gauge replaced.
2/22/2002	Computer problems	Monitor replaced
3/1/2002	Halon fire protection system replaced with inergen system	
3/5/2002	Lube oil problems	Changed demister filter
3/11/2002	Lube oil problems	Secure guard on lube pump motor
3/18/2002	DC ground	Ground on DC libe pump # 2
3/21/2002	DCS Logic changes	EGT mod's
3/22/2002	DC ground	Control relay in charger
4/4/2002	Fuel system trouble	Pump # 1 new shaft and impellar
4/8/2002	GGA failed start	Loue failure on first try
4/12/2002	Lube system trouble	Failed control relay
4/15/2002	Lube oil problems	Demister failure due to faulty control relay
4/18/2002	Lube oil repairs	Repairs to Demister and evaporator
4/22/2002	GGA failed start	Incomplete sequence
4/23/2002	Lube oil ststem problems	System not shutting down on GT stop.
4/24/2002	Compressor problems	New breaker installed
4/26/2002	Compressor problems	Unloader failure
4/29/2002	Compressor problems	Oil level switch problem
5/1/2002	Compressor problems	Unloader failure
5/6/2002	GGA failed start	Incomplete sequence
5/8/2002	Generator trip	TRTD failure
5/9/2002	Site assessment	Begin of site assessment foi oil contamination
5/14/2002	GGA & GGB louvers	Contractor installing louvers
5/16/2002	Lube oil problems	Oil leak in jacking pump
6/4/2002	GGA failed start	Incomplete sequence
6/6/2002	Fuel system repairs	Repairs made in off-loading area
6/12/2002	Air compressors replaced	
6/18/2002	Installed heat tracing cable on GGB	
6/28/2002	AVR faullt alarm	Reset, no problem found
7/15/2002	GGA failed start	EGT Alarm
7/16/2002	GGA failed start	EGT Alarm
7/16/2002	Lube oil System alarm	High Temp alarm
7/16/2002	GGA trip	Clutch malfunction
7/17/2002	Genrator high temp alarm	Glycol system trouble
8/6/2002	Lube oil system trouble	Demister louver repaired
8/12/2002	GGA Exhaust stack	Repairs
8/14/2002	GGA Expansion joint	Repairs
8/16/2002	Replaced computer monitor	
8/20/2002	GGA Repairs	Replaced bottom deflector ring
9/3/2002	GGB Exhaust stack repairs started	
9/6/2002	GGB expansion joint repairs started	
9/23/2002	GGA install fire louvers	
9/24/2002	GGB install fire louvers	
9/27/2002	Unit controls	Work on control boards
9/30/2002	Generator Filters replaced	
10/3/2002	GGA Inspection	Entry guide vanes inspected
10/30/2002	Speed switch failure alarm	DCS card failure
11/8/2002	GGA failed start	
11/8/2002	Generator showing 75 rpm at stop	control card failure
11/19/2002	GGB fuel leak	failed Jordan valve
12/2/2002	Jacking pumps cutting in and out	DCS control card failure
12/6/2002	DCS control problem with speed	Card failure

12/13/2002	N4 speed awitch repairs	
1/19/2005	Cooling system	replaced float switch in glycol tank
1/20/2005	Fuel leak	Leak on main fuel filters
1/24/2005	GGA Failed start	Incomplete sequence on first attempt
1/26/2005	Air syatem trouble	Pressure switches repaired
12/28/2005	DC Ground	Ground on standby diesel
2/7/2005	Cooling system	Glycol conditioner added
2/8/2005	Cooling system	Glycol level switch repaired
2/23/2005	Air system trouble	Air line frozen
3/1/2005	Fuel system trouble	Calibrate fuel gauge
3/9/2005	Start fail	No ready lights
3/31/2005	Ready lights out	Battery ground
4/11/2005	Asbestos site assessment	
4/12/2005	Generator trouble	Excitor trouble
4/22/2005	Replaced Brg # 3 vibration pickup	
5/2/2005	Failed start	Vibration alarm
5/3/2005	Cooling system trouble	Glycol Fan # 2 noisy bearing
5/17/2005	T5 Rad fan repairs	
5/19/2005	GGB Snow Doors	Repair grease lines
5/26/2005	Fuel system trouble	Varec gauge calibrated
3/30/2005	Air Dryer and GGB snow doors repaired	
6/7/2005	Installed air conditioning unit	
6/8/2005	Standby diesel fuel tank replaced	
6/9/2005	Fuel leak	Identified fuel in ground between fuel forwarding building and unit.
6/13/2005	Unit available in emergency only	Has to be personal on site due to fuel leak
6/15/2005	GGB unavailable	Failed snow doors
6/23/2005	Control cables	Had to be relocated due to fuel lines replace
6/28/2005	GGB Snow doors	repairs to oil lines to snow doors
7/4/2005	Control building roof repairs by contractor	
7/27/2005	Fuel System	Contractor started installation of motorized fuel valves
8/4/2005	Fuel system laeks	Contractor completed replacing fuel lines between fuel forwarding building and units as well a sump drain lines as a result of fuel leak
8/4/2005	GGA & GGB Inspections	Hot end inspections completed
8/10/2005	Logic changes for motorized fuel valve	
8/11/2005	GGB EGT problems	Fuel nozzels checked and logic changes
8/12/2005	GGB failed start	Fuel nozzel leaks. GGB unavailable thru weekend. Replaced flex line
8/15/2005	GGB EGT trip	
8/16/2005	GGB EGT	interchanged nozzels 6 & 8
8/17/2005	GGB EGT	Interchanged nozzels from A to B and swapped thermocouples. No success
8/19/2005	GGB Logic	Breaker must be open in order to start GGB
8/22/2005	Field ground alarm	
8/23/2005	Generator stator filter alarm	Field brush connection broken
8/23/2005	Generator Field	Repairs to brush connection on alternator
8/29/2005	GGA EGT trip	GGA clutch malfunctioned on shutdown as well
8/31/2005	GGB EGT trip	Two attempts
9/2/2005	GGB EGT trip	EGT trip on 3 attempts
9/2/2005	GGA Clutch failued	Suspected proximity switch
9/19/2005	GGA Clutch Sticking	
9/19/2005	GGB EGT	Nozzels interchanged and changes to logic
9/20/2005	GGB EGT	Logic changes and repairs to nozzel fuel leak
9/21/2005	GGB EGT Trip at 18 Mw	
9/27/2005	GGA failed start	Incomplete sequence. Started on 3rd attempt
9/15/2005	Multiple alarms	Lightning strike. Vibration relan and anunciator cards damaged
11/10/2005	Sump level logic modified	
11/15/2005	GGB EGT	Nozzels removed
11/16/2005	GGB EGT	Rolls Wood and ABB rep's on site for inspection. Fuel leak on startup
11/17/2005	Unit controls DC ground	GGB Tested to 18 mw where EGT tripped
11/21/2005	GGB Snow doors	Air leak
11/23/2005	GGA Vibration Alarm	Alarmed on startup, reset okay
12/15/2005	Fuel leak	Failed safety valve in fuel forwarding building. All 3 valves replaced.
12/20/2005	GGB Fuel	Jordan valve replaced

Major Mechanical Projects Completed Since 1980 - Hardwoods

1. Fern Engineering Modifications. Primarily replaced the casing on each of the 4 Curtiss Wright power turbines (Stephenville and Hardwoods) which were prone to cracking. Other smaller components were replaced as well. Approx. cost $4 million. (1988)
2. Redesign of inlet air filtration system for gas engine and generator. (early 1990's)
3. Exhaust stack replacement. Existing interior silencer panel was reused. (1992)
4. Snow door actuation was converted from electric to pneumatic. (mid 1980's)
5. Hardwoods B engine serial # 202223 overhaul. (1993)
6. Air Conditioner, for Gas Turbine Control Room, replaced. (2005)
7. New double walled fuel tank for Diesel Gen. (2005)
8. Diesel Gen. replaced. (Nov. 2005)
9. New Flow meter for G. T. (2005)
10. Installed motorized valve fuel line by main tank. (2005)
11. Fuel lines for G. T. installed above ground between unit and the fuel forwarding pumphouse. (2005)
12. Battery Bank replaced 2005 and new standby charger. (2005)
13. Installed new core in Heat Exchanger for MLO system. (2003)
14. Installed new expansion joints in stacks. (2004)
15. Repairs to Glycol housing. (2006)
16. Both Air compressors have been replaced.
17. Gas Turbine and Generator Modules Fire Systems Replacement (Inergen): Hardwoods (2002)

Some information on the projects listed above has been included in the **Reports** folder.

There are many other projects that you may wish to have information on. Please review the document titled ***Mechanical Thermal Projects*** contained in this folder.

NOTE: Hardwoods Gas Turbine Site projects begin with **108**.

If you would like to have information on any of the projects listed, please submit a request to Andrea MacDonald for this information.

11/12/2007

Hardwoods Civil Engineering Projects

HWD

1) Tank Farm upgrades: <1996/97>
- 1 tank completed removed
- remaining tank cleaned, weld repairs, paint interior floor
- new dyke liner throughout (tank was lifted)
- dykes re-shaped
- new dyke section (to reduce size of containment area)
- new piping within tank farm

2) Paint exterior of tanks <2000>

3)

Gas Turbine Condition Assessment Information - Hardwoods

Major Projects (Electrical) - Hardwoods

1. Switchgear Upgrades (information contained in budget proposal) Hardwoods – 1998

    The proposed work involved:

    a. Purchase and installation of new main breaker. This breaker will be rated at 3000 Amp with an interrupting capacity of 28 kA. The existing breaker will be assessed for use as a system spare to serve both the Stephenville and Hardwoods site.

    b. Post insulators and insulation coverings on the rigid bus bars will be replaced/upgraded sufficient to re-rate the switchgear to 15 kV class.

2. Battery Bank Replacements: Hardwoods - 2005
    The 125V 900 amp-hour VRLA bank for the Hardwoods Gas Turbine was replaced in 2005. The intention was for the replacement bank to have the same ratings as the previous bank, but we have been unable to confirm this.

3. Rotor Rewinding and Other Associated Repairs: Hardwoods - early 90's
    a. Files cannot currently be located for this job.

4. Brushless Exciter Vibration Issues Hardwoods – 1994
    a. In October of 1994 high frequency vibration signatures were observed on the exciter and 'B' end alternator bearing. It is unclear as to the cause of these vibrations, and what, if any steps were taken to address the situation.

5. Governor Repairs Hardwoods – 1995/1996
    During the 1994 outage very low ramp rates existed and problems were experienced with the governor. Repairs were made to the governor in 1995 and 1996. Governors were calibrated and droops were setup.

6. Voltage Snubbers: Hardwoods
    This was likely a P&C Project.

Protection and Control Major Projects - Hardwoods

1. Control System Upgrade: 1997. This entailed removing approximately 250 electromechanical relays and timers and replacing the controls with a distributed control system. The DCS included a PC-based operator interface. Commissioning of controls performed by ABB (ETSI).
2. AVR Replacement: 2006. The Brush BAVR was removed and a new ABB AVR was installed. For details, contact Alex Lau at 737-1788. This has not been done at Stephenville yet.
3. Inverter replacement: Hardwoods - Mar. 2006. Inverter failed and was replaced.
4. Miscellaneous. Thermocouple blocks replaced at Hardwoods on 2003. Terminal blocks in junction boxes located around the unit were replaced at Hardwoods a few years ago due to the condition of the original set. Snubbers (free-wheeling diodes) were replaced at Hardwoods. Some had shorted out a year ago. These were for noise reduction.
5. Emergency backup diesel generating units installed: 2005. Diesel Generating Unit #572 including 600V control panel and backup battery charger installed in existing diesel building. The diesel unit is designed to start automatically with the loss of AC station service supply to the gas turbine unit and in turn supply power to the backup battery charger which ensures the integrity of the 125 Vdc supply to the gas turbine itself during its starting cycle. The diesel unit also provides a backup AC supply for one of the air compressors should the stored air supply run low during attempted start(s) of the gas turbine unit.
6. NOTES:
    a. Vibration Monitoring Systems at both sites are to be replaced by Dec. 2007. This is a 2007 project. The IRD Mechanalysis units are to be replaced but the accelerometers will be retained.
    b. The Operator Console (PCView software, QNX operating system, Xycom industrial PC) at Stephenville experienced a hard-drive failure. Efforts are ongoing to prepare cost for software and hardware upgrade for both sites to prevent extensive loss of local monitoring in the event of PC-related failure. Both consoles are original vintage (i.e. circa 1999).

Major Mechanical Projects Completed Since 1980 - Stephenville

1. Fern Engineering Modifications. Primarily replaced the casing on each of the 4 Curtiss Wright power turbines (Stephenville and Hardwoods) which were prone to cracking. Other smaller components were replaced as well. Approx. cost $4 million. (1988)
2. Exhaust stack replacement. Snow doors were modified from electric actuation to pneumatic. Total cost $1.2 million. (1989)
3. Stephenville B engine serial # 202224 overhaul. (2000)
4. Gas Turbine and Generator Modules Fire Systems Replacement (Inergen): Stephenville (2002)

Some information on the projects listed above has been included in the **Reports** folder.

There are many other projects that you may wish to have information on. Please review the document titled ***Mechanical Thermal Projects*** contained in this folder.

NOTE: Stephenville Gas Turbine Site projects begin with **106**.

If you would like to have information on any of the projects listed, please submit a request to Andrea MacDonald for this information.

Stephenville Civil Engineering Projects

SVL

1) Tank Farm upgrades: <1999,2000>
   - 3 tanks refurbished (interior cleaned, weld repairs, paint floor)
   - inspection of tanks
   - new dyke liner throughout (tank was lifted)
   - dykes re-shaped
   - new granular dyke materials
   - new sump
   - new piping (within tank farm)

2) Paint exterior of tanks <2004>

3) Painted exterior of GT with rubberized coating system. <2006>

Gas Turbine Condition Assessment Information - Stephenville

Major Projects (Electrical) - Stephenville

1. Installation of 15kV Metal Enclosed Switchgear Assembly and Bus Duct: Stephenville – 1998
   This entailed the design fabrication, factory testing, supply and delivery of a 15kV Metal Enclosed Switchgear Assembly. Scope included:

   a. Supply, delivery and placing on existing concrete pad an outdoor, walk-in type 15kV metal enclosed switchgear.
   b. All tools, cranks, and other equipment required for normal operation.
   c. Spare parts.
   d. Two sections of 15kV, 3 phase, non-segregated bus duct between the switchgear and the main transformer, and between the switchgear and the generator.
   e. Structural steel supports to support bus duct.

2. Battery Bank Replacements: Stephenville - 2005
   The 125V 900 amp-hour VRLA bank for the Hardwoods Gas Turbine was replaced in 2005. The intention was for the replacement bank to have the same ratings as the previous bank, but we have been unable to confirm this.

   The VRLA bank for the Stephenville Gas Turbine was also replaced, around the same time, but we have been unable to find further details.

Protection and Control Major Projects - Stephenville

1. Control System Upgrade: Stephenville - 1999. This entailed removing approximately 250 electromechanical relays and timers and replacing the controls with a distributed control system. The DCS included a PC-based operator interface. Commissioning of controls performed by ABB (ETSI).
2. Inverter replacement: Stephenville Feb. 2004. Inverter failed and was replaced.
3. Emergency backup diesel generating units installed: 2005. Diesel Generating Unit #571 including 600V control panel and backup battery chargers installed in new 3.6m x 4.8m building. The diesel unit is designed to start automatically with the loss of AC station service supply to the gas turbine unit and in turn supply power to the backup battery chargers which ensures the integrity of the 125 Vdc and 250 Vdc supply to the gas turbine during its starting cycle. The diesel unit also provides a backup AC supply for one of the air compressors should the stored air supply run low during attempted start(s) of the gas turbine unit.
4. Miscellaneous. The type J and K thermocouple wire and terminal blocks in various junction boxes were replaced during the controls upgrade ('99) at Stephenville.
5. NOTES:
    a. Vibration Monitoring Systems at both sites are to be replaced by Dec. 2007. This is a 2007 project. The IRD Mechanalysis units are to be replaced but the accelerometers will be retained.
    b. The Operator Console (PCView software, QNX operating system, Xycom industrial PC) at Stephenville experienced a hard-drive failure. Efforts are ongoing to prepare cost for software and hardware upgrade for both sites to prevent extensive loss of local monitoring in the event of PC-related failure. Both consoles are original vintage (i.e. circa 1999).

APPENDIX 4
ALBA REPORT – OLYMPUS ENGINES BORESCOPE INSPECTION
HARDWOODS AND STEPHENVILLE

APPENDIX 4
ALBA REPORT – OLYMPUS ENGINES BORESCOPE INSPECTION
HARDWOODS AND STEPHENVILLE

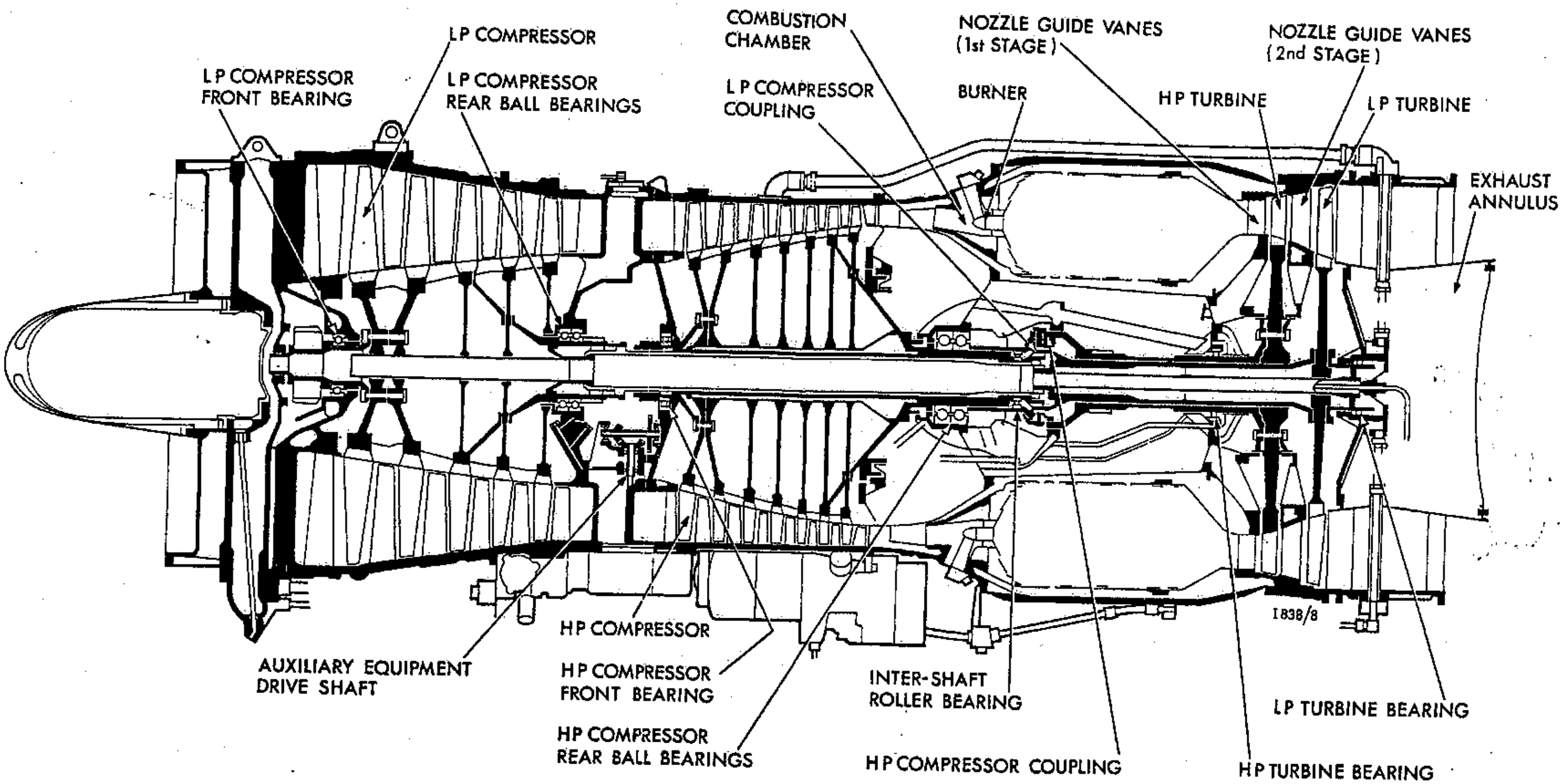


Figure 2-3 Section Through Olympus Gas Generator Newfoundland (Hardwoods) Reissued 20 November 1978

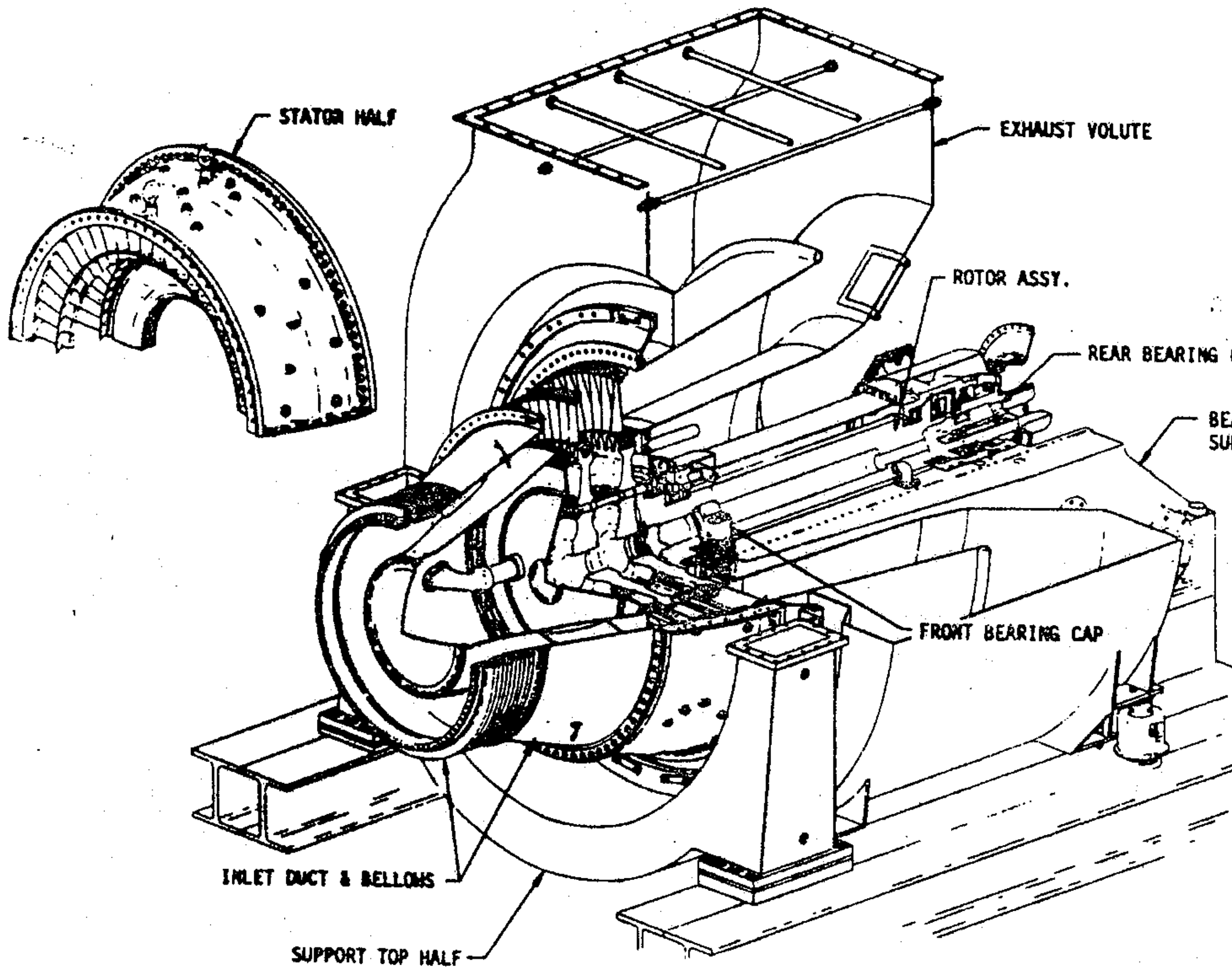


Figure 2-58. CT-2 Power Turbine Major Component Assemblies

ALBA POWER

Inspection Report
To

HYDRO

HARDWOODS
STEPHENVILLE

For Olympus Borescope inspection

Proposal Number: Alba 1457

Date: May 30 – 31 2007 Hardwoods & 6-7 June 2007 Stephenville

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Introduction

After a successful tender award Alba Power travelled to site to review the units at Hardwoods facility on 30 May 2007.

Alba Power completed the works at site, and due to findings was requested to return to Stephenville for further unit investigation.

This document will detail the steps taken, remedial works completed and future recommendations.

Alba Power would like to take this opportunity to thank the client and staff at Newfoundland Hydro generating site for the assistance and approach to Alba Power, this was greatly appreciated an we look forward to assisting you in the future.

If you do have any questions or queries please do not hesitate to contact us, your contact for this proposal is as follows:

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1 Olympus Borescope Inspection Hardwoods

On Site Personnel- Mr Campbell Archibald and Mr Colin Smith

Date of inspection – 30 - 31 May 2007

Inspection Review

On arrival at site a Tool Box review was held with Mr Nelson Seymour. This covered all aspects of site-specific nature including health and safety.

After review it was noted that the client had;

- Removed burners from both units
- Made access to the plenum for compressor inspection

Alba Power then proceeded to the worksite to complete the borescope inspection.

Workscope Review

The following are details of the workscope completed at site;

1.1.1 Wednesday 30 May 2007

After review Alba Power completed unit A and B borescope inspections.

At the clients request the burners or filters were not inspected or cleaned.

The air intake housing was rectified after it was found that the circlip had moved.

1.1.2 Thursday 31 May 2007

Alba Power was requested to return to site to view the start of the units.

Unit B operated correctly at first attempt. Unit A suffered from high deviation, after thermocouple review and burner cleaning the unit operated correctly.

2 Borescope Results

As detailed within our workscope above the unit was borescoped throughout and within this report we will detail the sections accordingly.

All images will be provided separately on a CD for client files.

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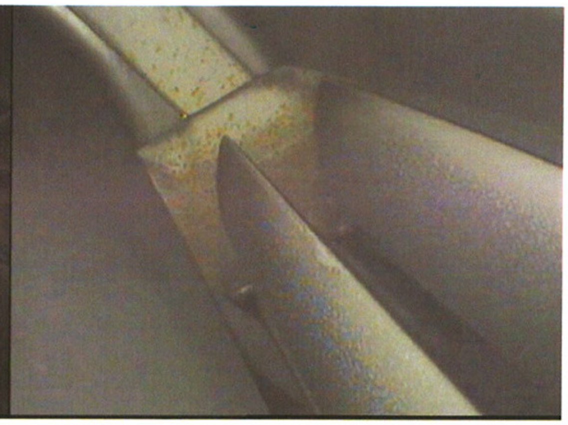
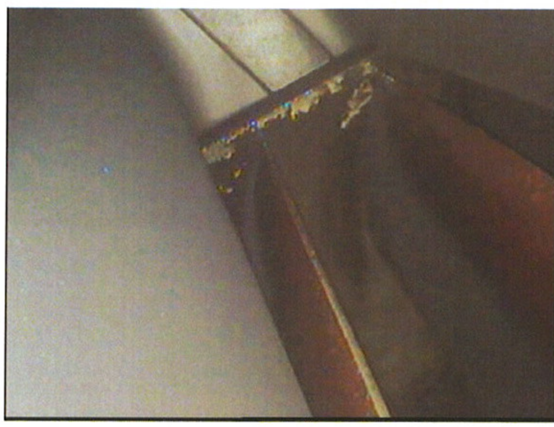
Compressor Section Unit A

In general the unit shows signs of corrosion, coating loss and staining due to location. This should be monitored and repaired prior to component degradation.

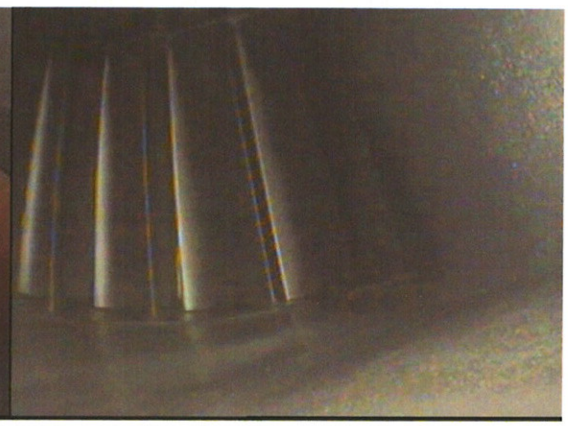
Inlet Guide vane corrosion



Stage 1 shroud corrosion



Stage 5 OGV coating loss



HP Compressor entries

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HP Compressor corrosion

HP Compressor corrosion

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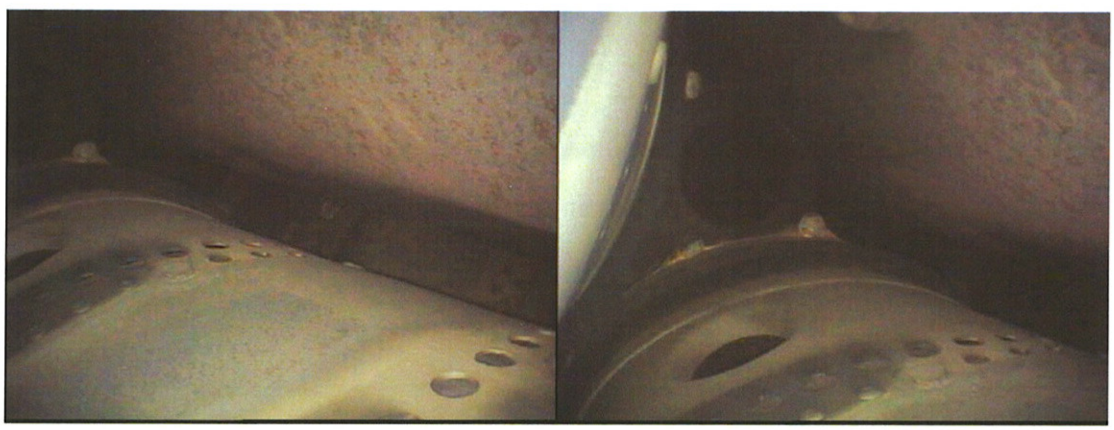
Combustion Section Unit A

The combustion cans are badly effected by carbon and have suffered material loss and cracking throughout. These cans should be changed at the earlier opportunity and a regime of waterwash and burner cleaning implemented every 6 months. This would prolong the life of the burners and cans.

Typically found carbon deposits



External view of Combustion cans and clamps

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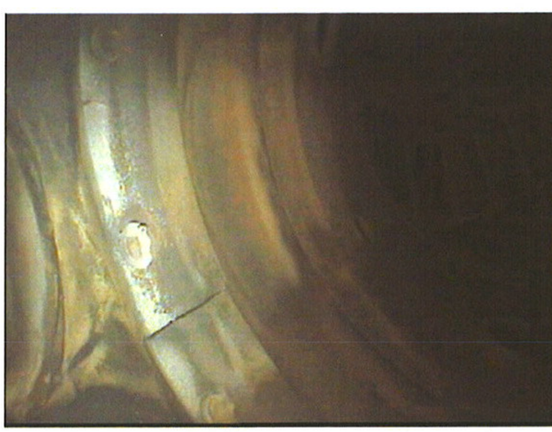
Cracking on No 3 Can

Material loss on combustion cans



Cracking of No5 Can

Material loss of No6 Can

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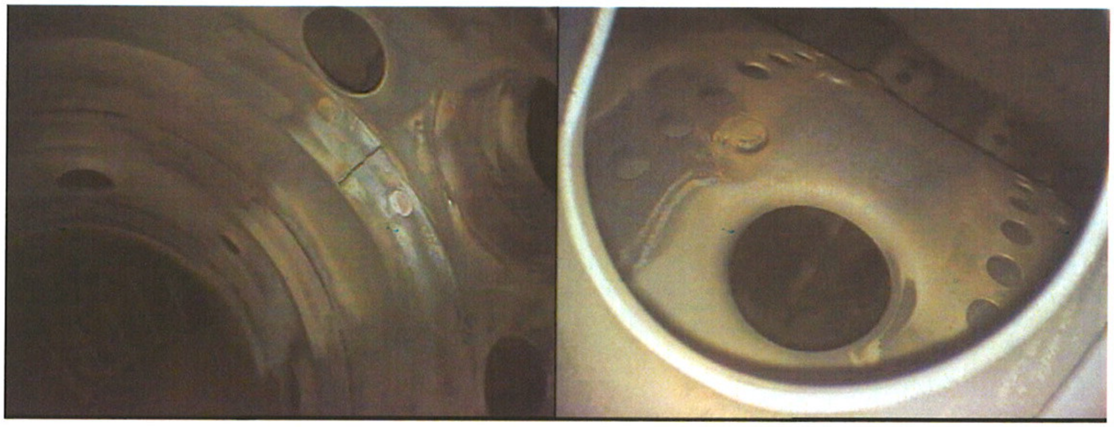
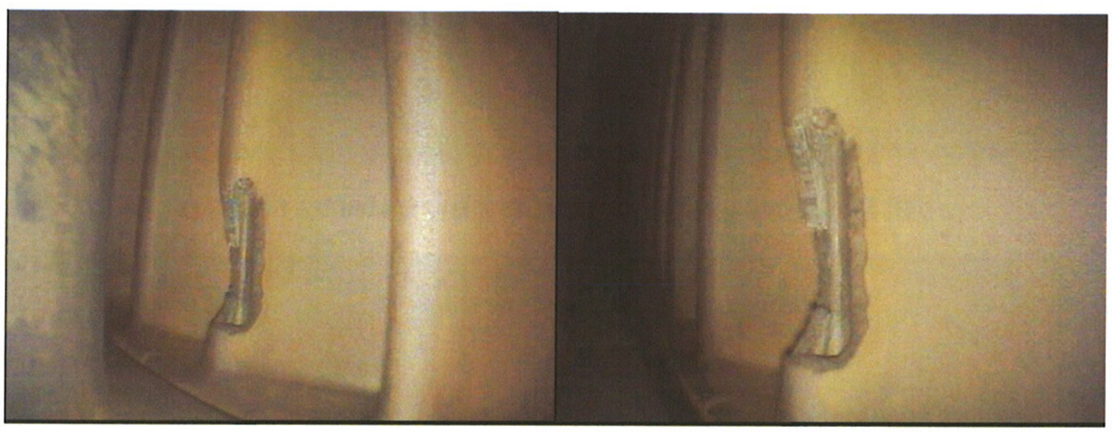


Cracking in No7 Can **External view of No7 Can**

Turbine Section Unit A

As can be seen a sizeable portion of 2 blades has been removed through collision or erosion. The remaining blades show sign of coating loss and pitting. Consideration should be given to removing the unit immediately for remedial works. This is currently a safety risk, and at risk of further damaging the unit should the blade fail entirely. (See Alba Power options for repair, overhaul and exchange)



HP Blade damage, blade found no 1

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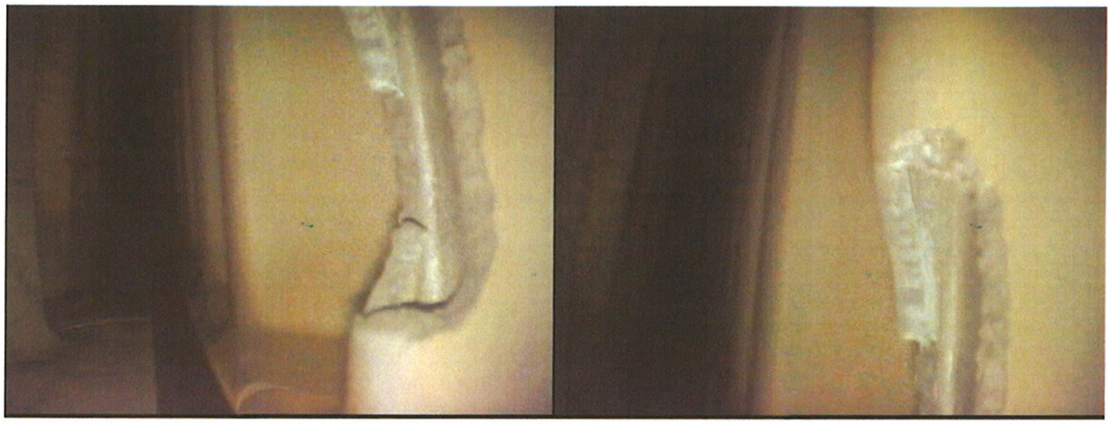

HP Blade damage, blade found no 1

HP Blade damage, blade found no 2 (separated by 4 blades)

HP blade damage, No2

Impact damage on 3rd blade

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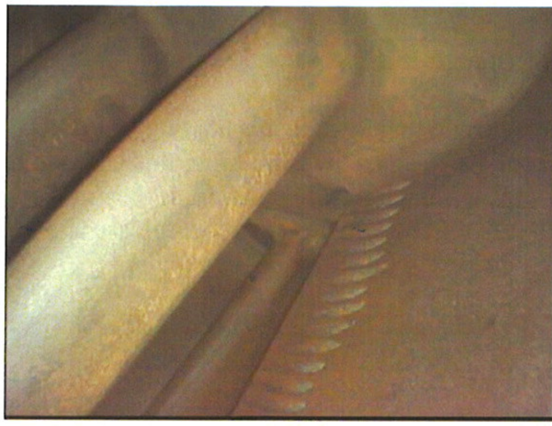
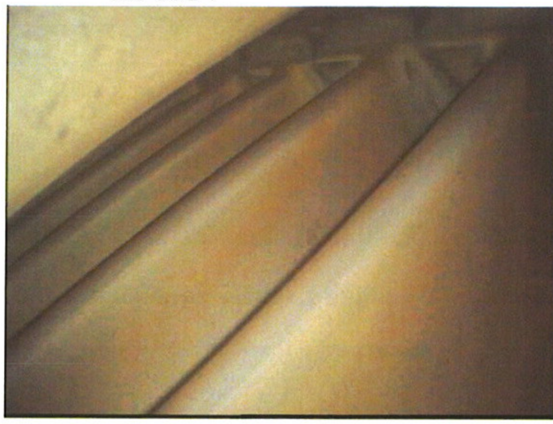
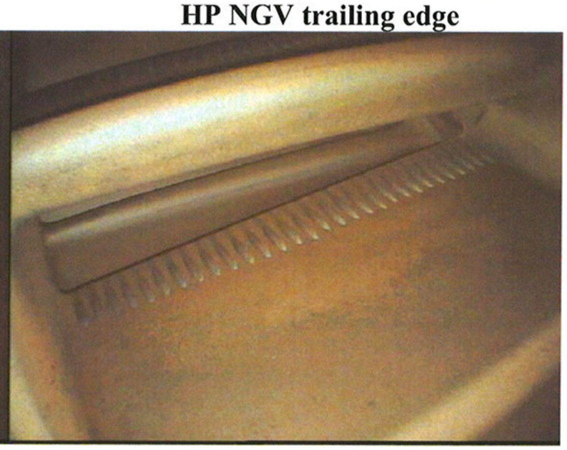


HP NGV

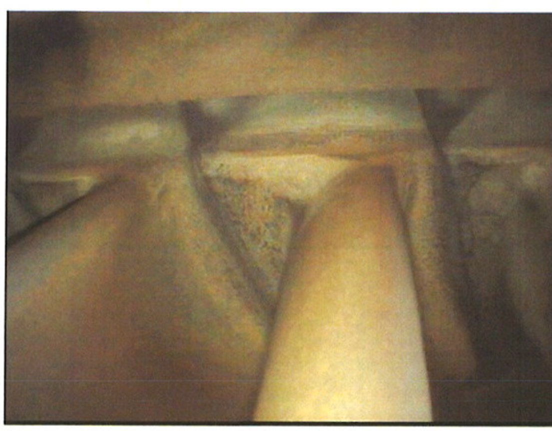
HP NGV trailing edge



HP Blade



HP NGV



HP Blade roots

HP Blade interlock

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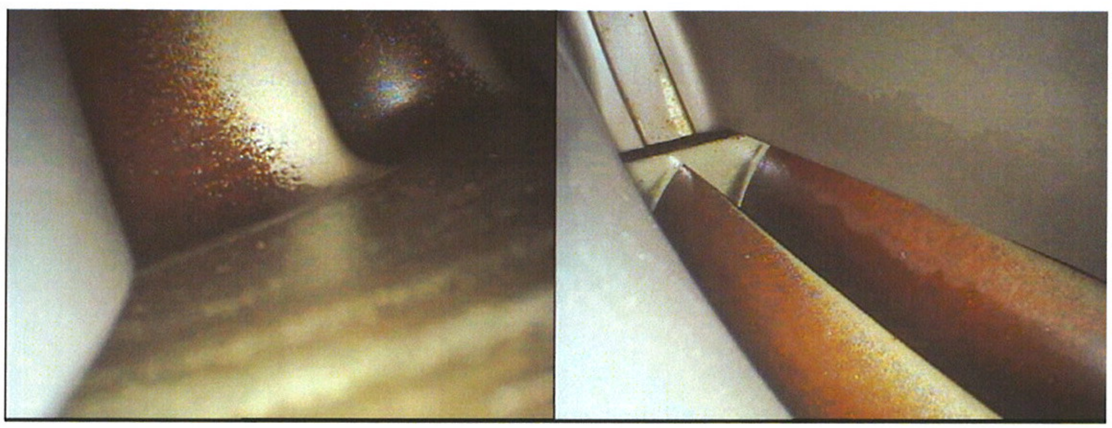
Compressor Section Unit B

The compressor section on this unit is extremely corroded with extensive coating loss and pitting. It was found that one of the HP compressor stator spacer was missing, this has lead to creeping of the remaining stators. These blades are now in an unsafe position, if they move slightly through operation further spacers and blades will be allowed to move, release and cause major damage to the unit. (Please see Alba Power proposal for onsite repair)

IGV Corrosion and pitting

Stage 1 spacer corrosion



Coating loss Stage 5

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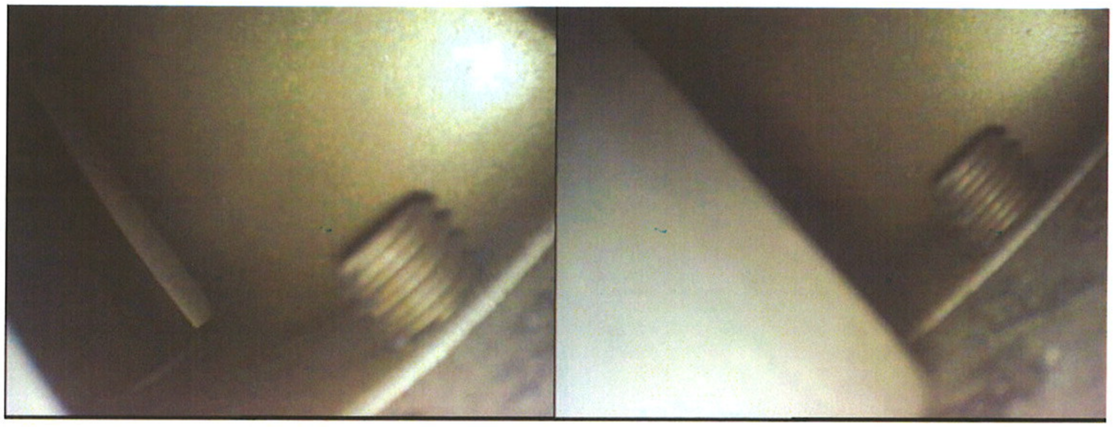
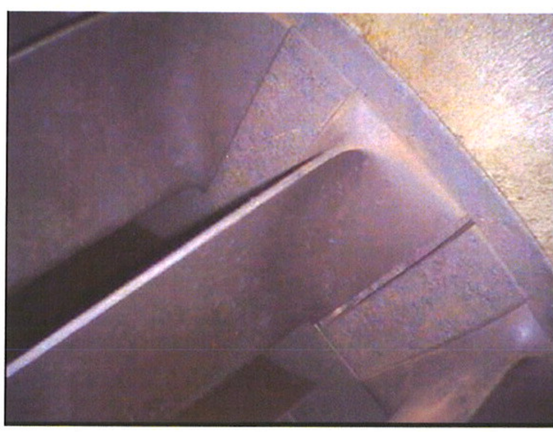


Incorrect stud fitment, stage 3

HP Compressor entry



OGV Stator gap | **missing spacer plate**

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Gap growth on stator

General condition of HP compressor

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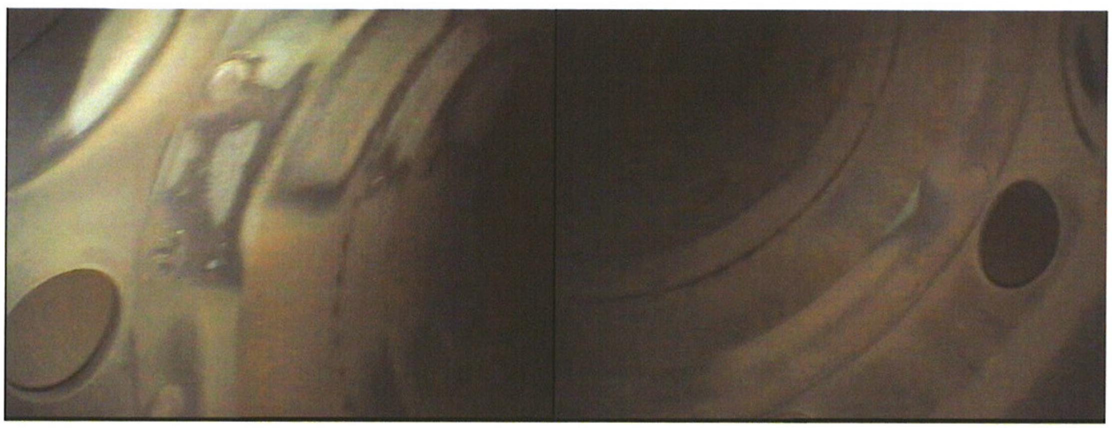
Combustion Section Unit B

The combustion second, although heavily affected by carbon, was in good condition and should be monitored yearly through borescope.

External Combustion can and clamp



General combustion chamber condition

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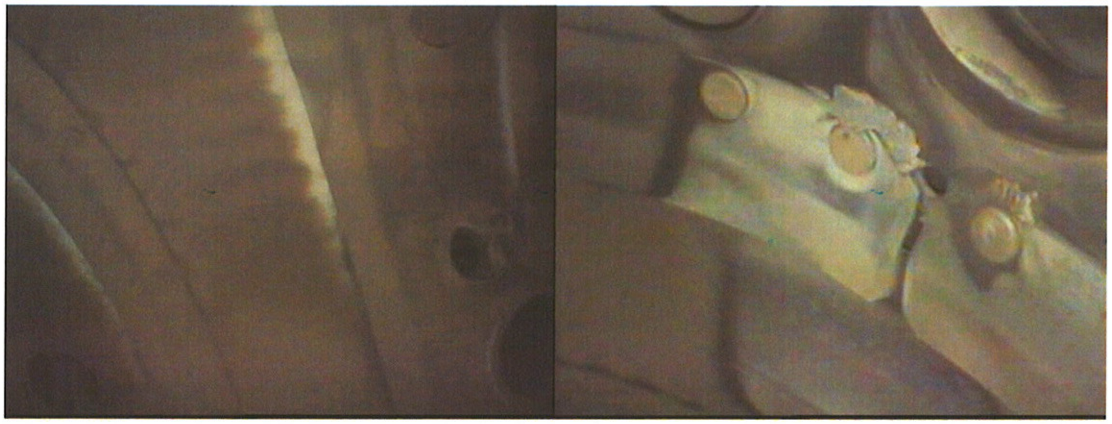

Combustion cracking and material loss

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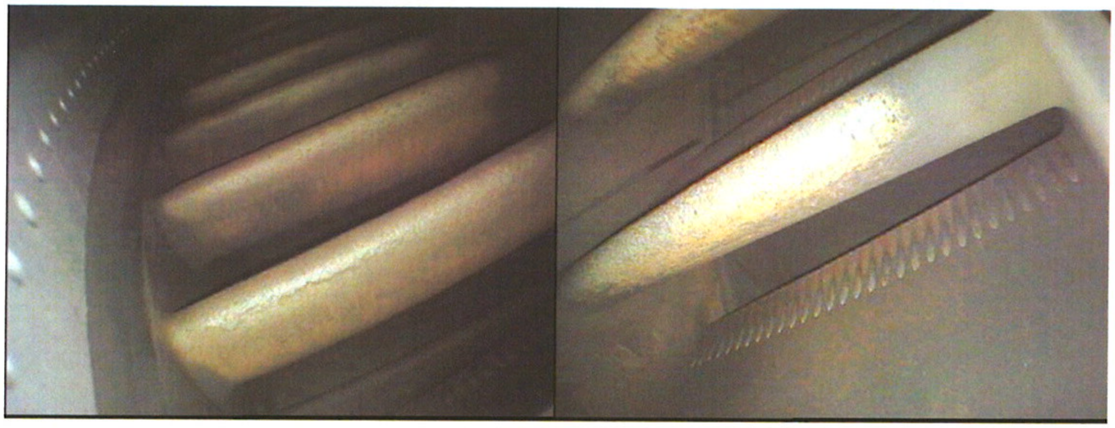
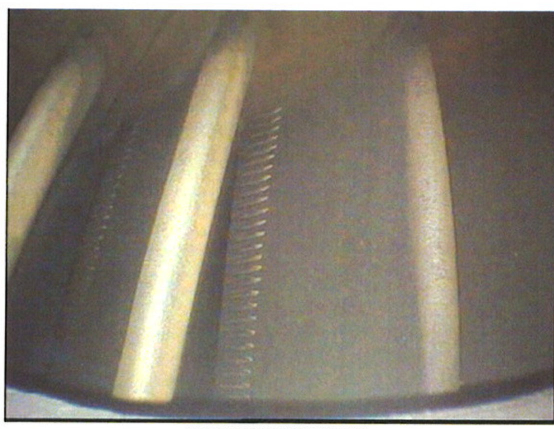
Turbine Section Unit B

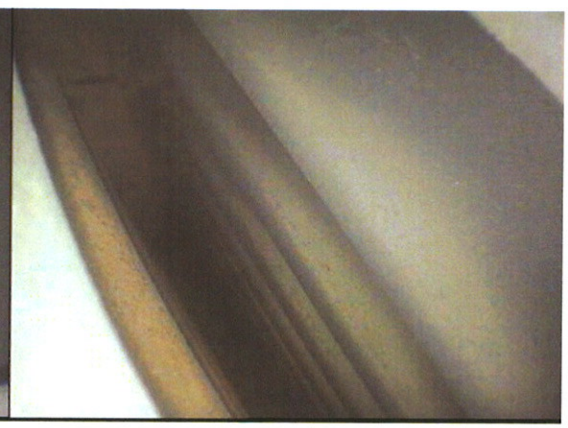
The turbine section was found to have heavy deposits of carbon, perhaps evidence of fuel pump issues. In the main the unit has coating loss and pitting on the HP NGV's, however this would continue in service through regular yearly monitoring.



HP NGV coating loss and staining



HP NGV Pitting



HP blade

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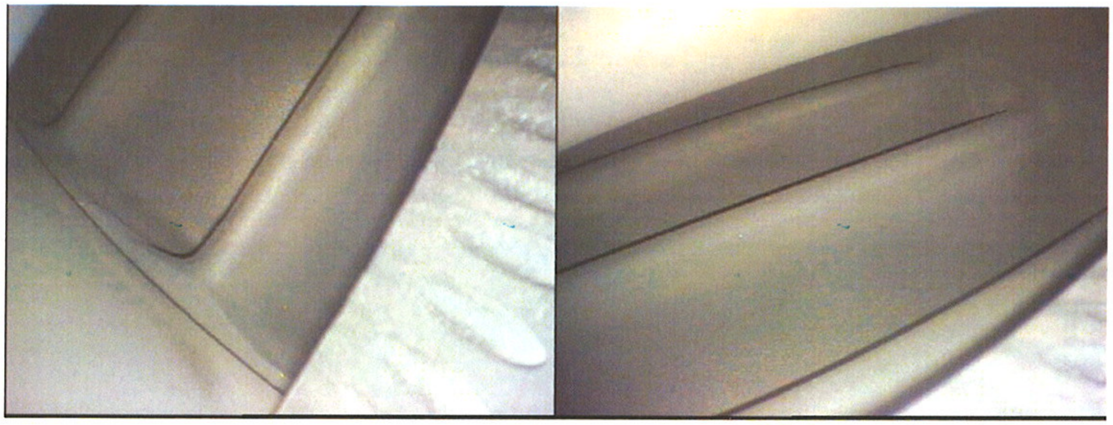

HP Blade condition

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3 Olympus Borescope Inspection Stephenville

On Site Personnel- Mr Campbell Archibald and Mr Colin Smith

Date of inspection – 6 – 7 June 2007

Inspection Review

On arrival at site a Tool Box review was held with Mr Nelson Seymour. This covered all aspects of site-specific nature including health and safety.

Alba Power then proceeded to the worksite to complete the borescope inspection.

Workscope Review

The following are details of the workscope completed at site;

3.1.1 Thursday 7 May 2007

After review Alba Power completed unit A and B borescope inspections.

At the clients request the burners or filters were not inspected or cleaned. It was noted that the intake assembly has moved with age, this should be rectified at the earliest opportunity.

Alba Power witnessed a failed start caused by starter motor issues.

4 Borescope Results

As detailed within our workscope above the unit was borescoped throughout and within this report we will detail the sections accordingly.

All images will be provided separately on a CD for client files.

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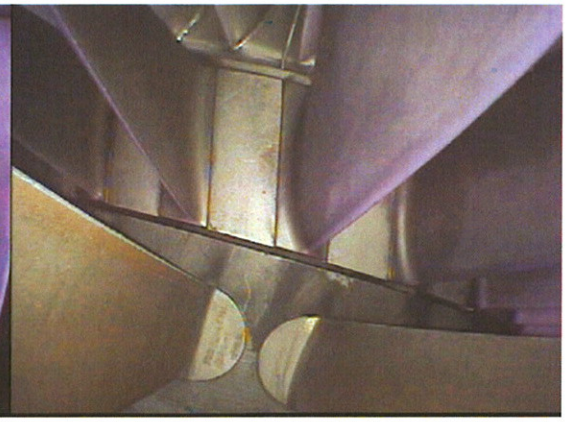
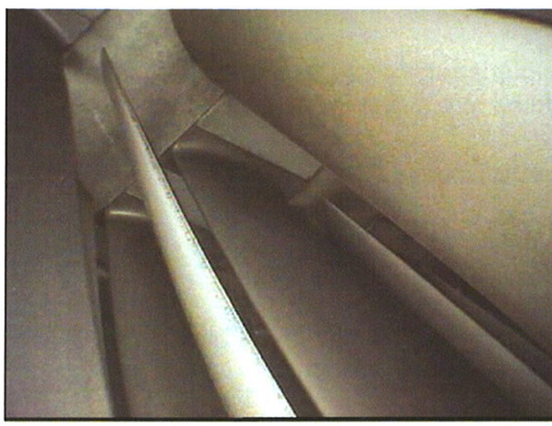
Compressor Section Unit A

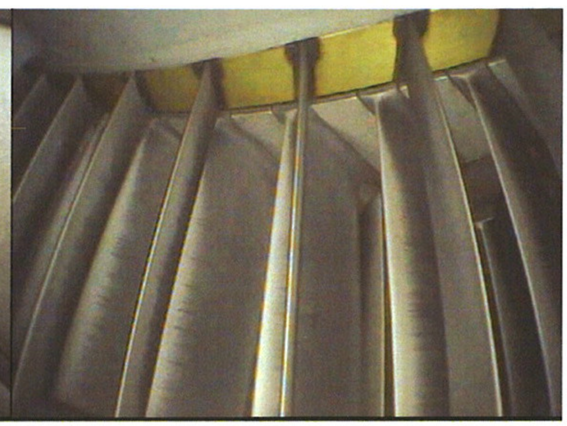
The unit was generally in clean condition with some minor corrosion and pitting. The rear of the HP compressor does show signs of corrosion.



Inlet Guide vanes

Inlet guide vane journal





Stage 1 blades

Stage 5 stator

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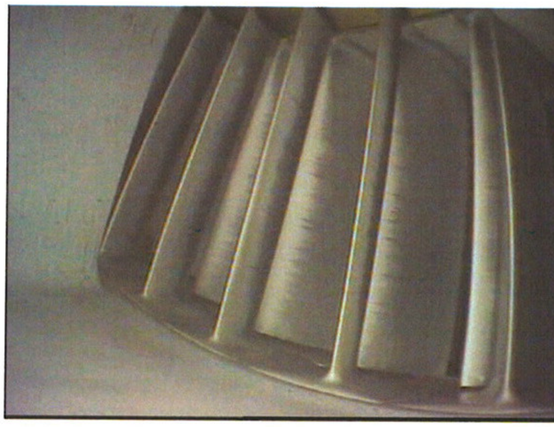
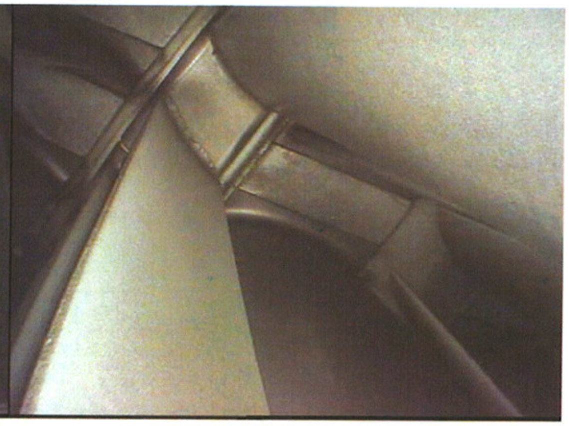
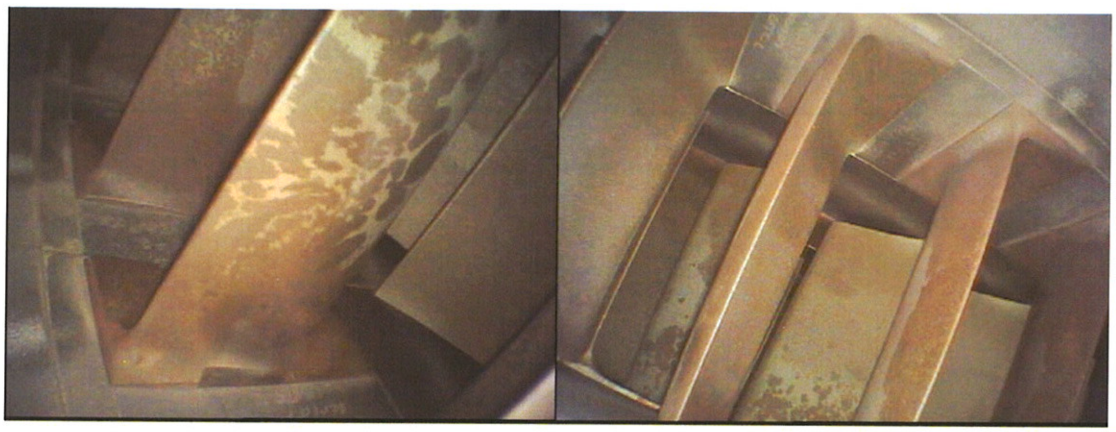


HP compressor stage 1



Stage 1 LP stator pitting



HP compressor corrosion

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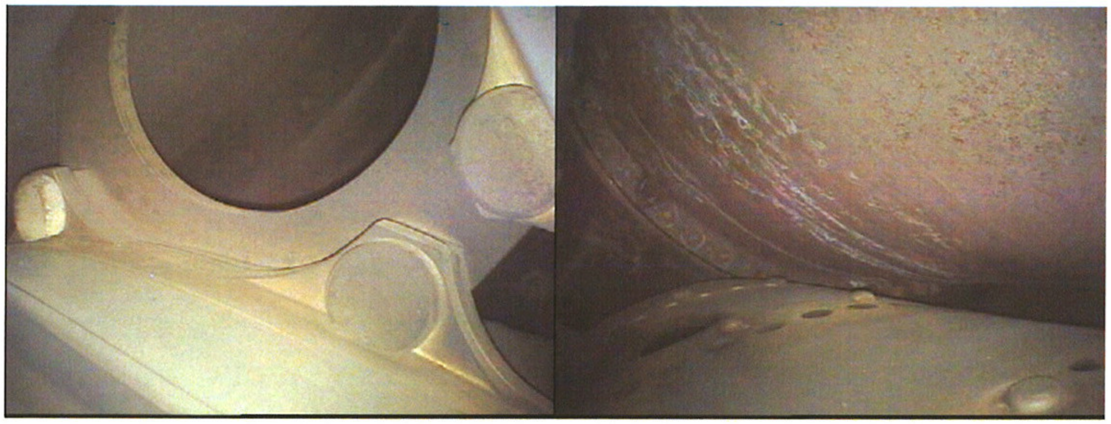
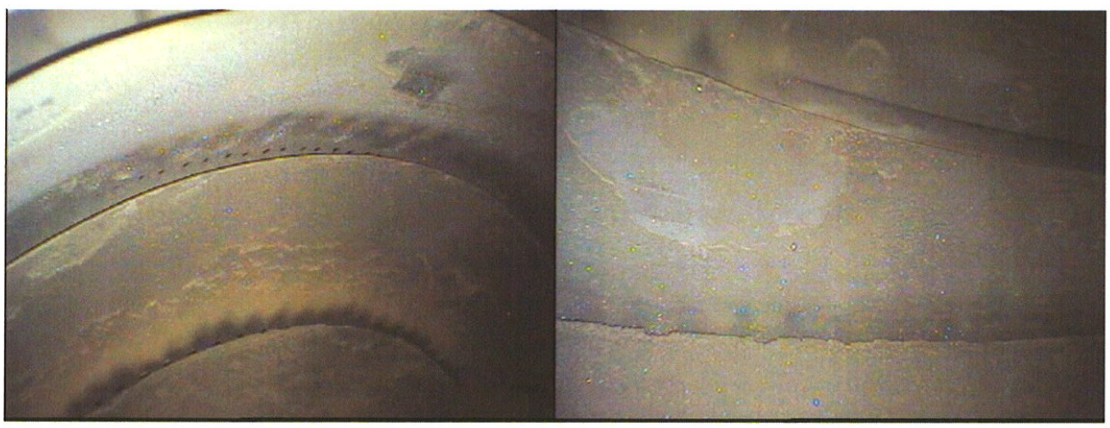
Combustion Section Unit A

The unit showed signs of coating loss with No5 can show excessive liquid staining. This could be a sign of burner wear or fuel pump issues.



Combustion can external images



Combustion can coating loss

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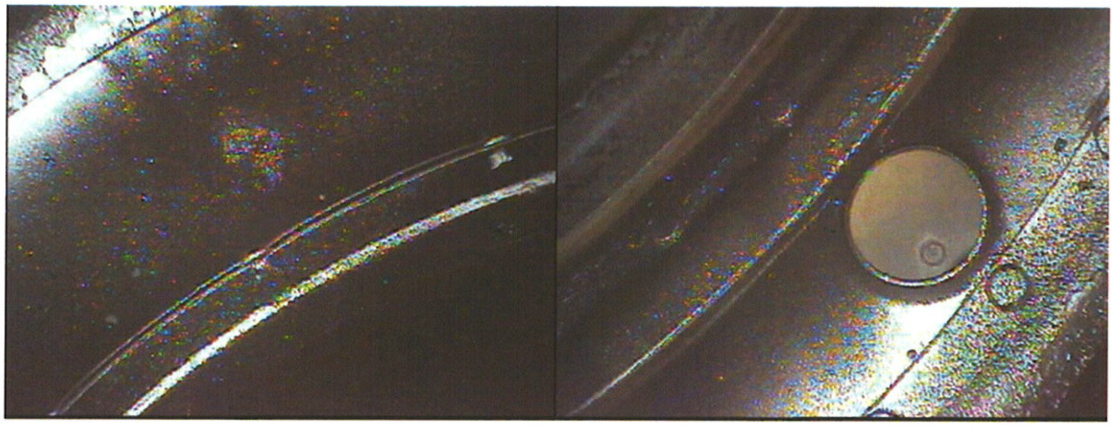

No 5 Staining

Turbine Section Unit A

The turbine section showed signs of excessive pitting and coking, again a sign of incorrect fuel flows. It would be advisable to plan for full inspection and recoating of the NGV's and blades before the capital equipment is beyond repair.

HP NGV,s with pitting and coking

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HP Turbine blade locking and pitting

HP blade and NGV coating loss and excessive

Excessive coating loss on HP NGV

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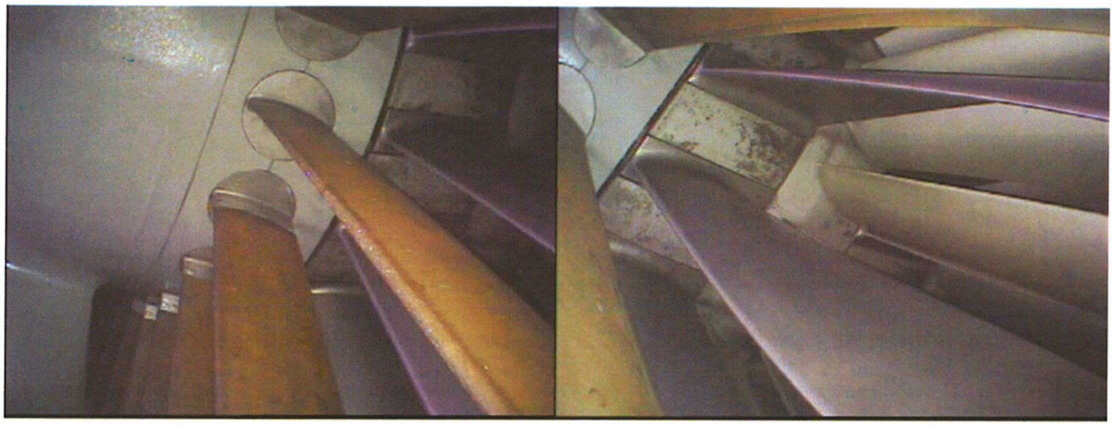
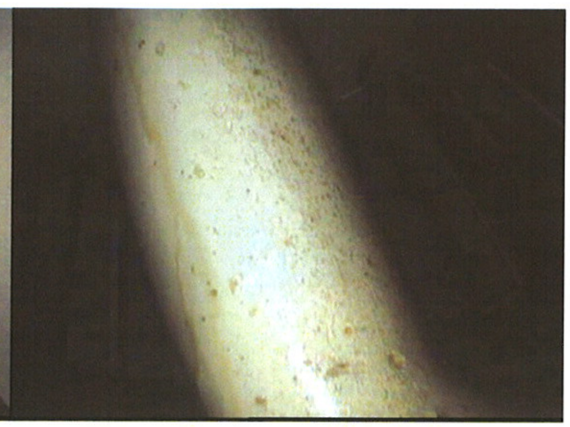
Compressor Section Unit B

The compressor shows sign of excessive pitting, particularly in the early stages and Intermediate casing. This should be monitored at next inspection.



IGV bushes and casing

Stage 1 corrosion



Intermediate case pitting

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Netherley
ABERDEENSHIRE
AB39 3QR
Scotland

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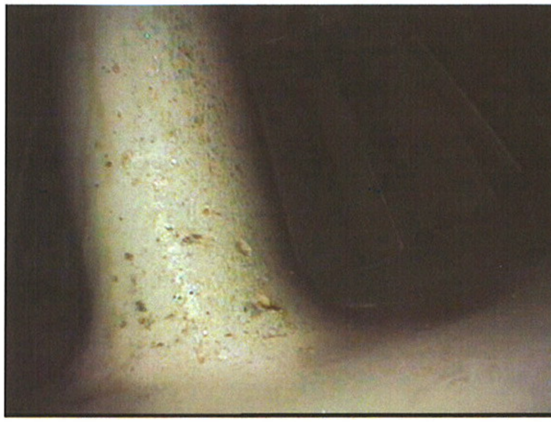
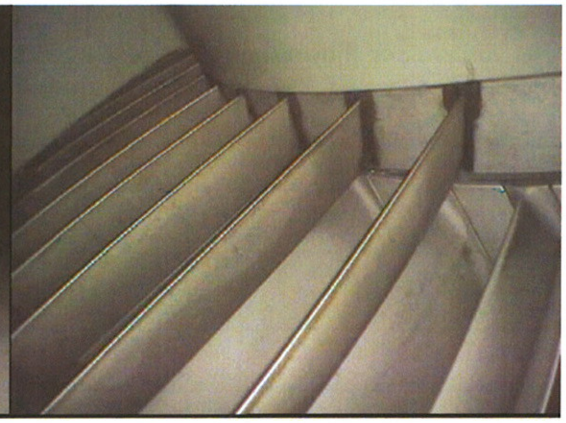
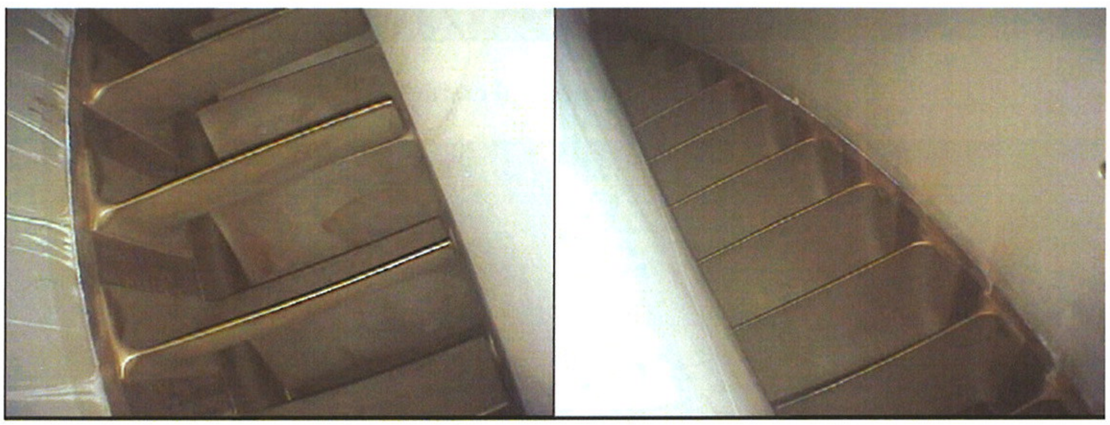




Intermediate case pitting **HP compressor entry**



HP compressor exit

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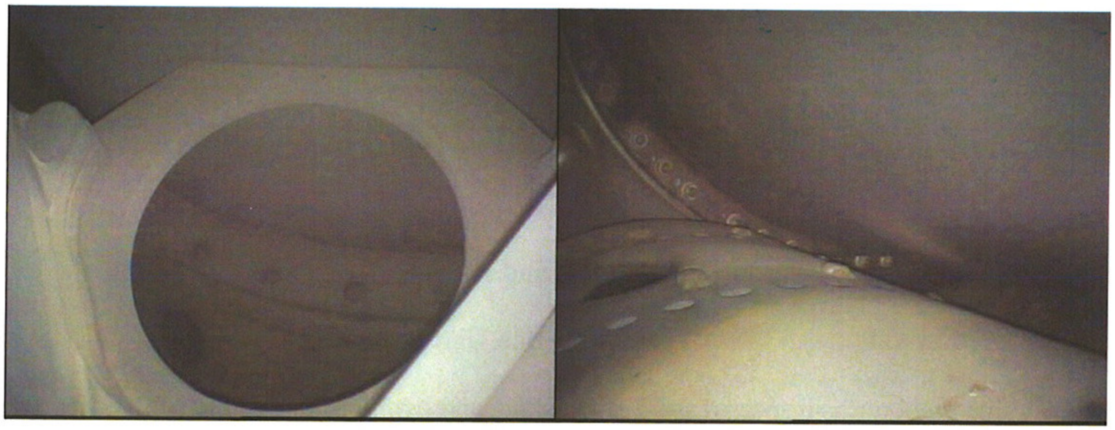
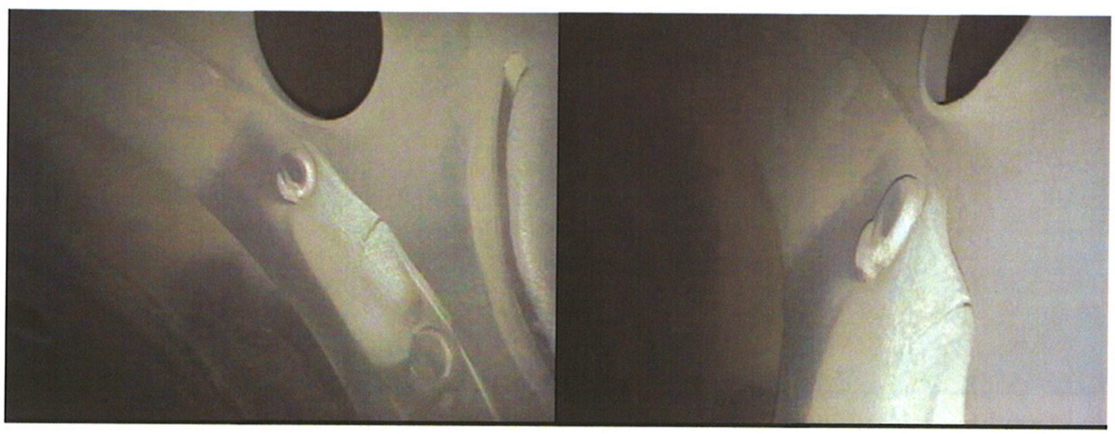
Combustion Section Unit B

The combustion area was generally in good condition with the exception of the No5 position, which has a large crack and material loss.



External area of combustion can



No 5 cracking

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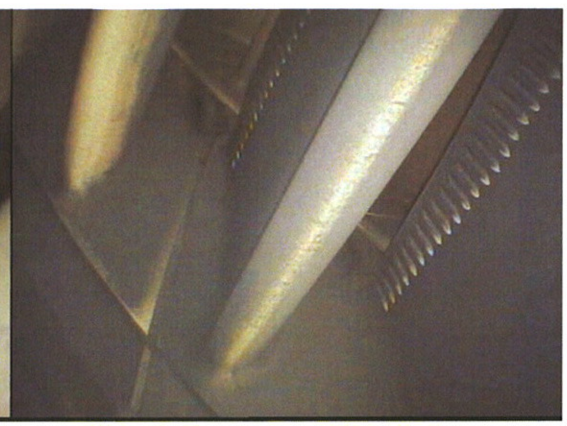
Coating loss and staining

Turbine Section Unit B

The turbine section was inspected and heavy coking and light cracking of the HP NGV's were found. This should be monitored for growth at next inspection period.

HP blade interlocks



HP NGV leading edge

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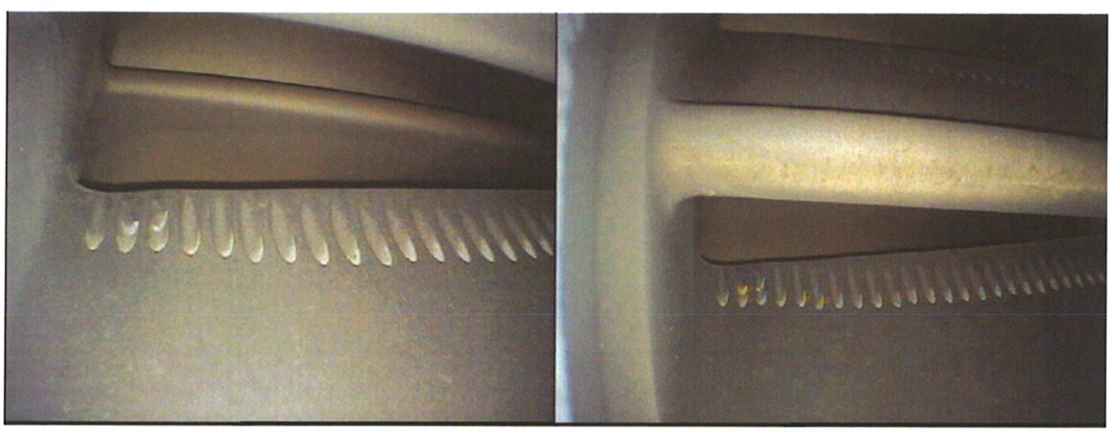
HP NGV damage

HP blade leading edge

HP NGV's



HP NGV trailing edge scallop

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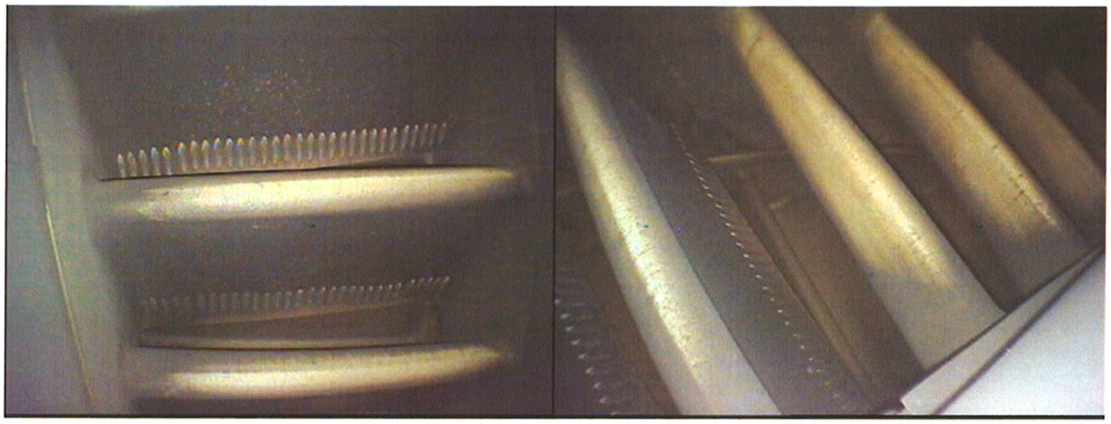

HP NGV coking

5 Additional items / workscope completed

In conjunction and review with the client the following additional scopes of work were completed and will be charged separately.

- Return travel and manpower to Stephenville inspection
- Return to Holyrood for start procedures

In addition Alba Power noted the following requirements that can be supplied or quoted on request;

- New Fuel rail supply for Holyrood
- Transition ducting for Holyrood
- Ignitors for all sites

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6 Conclusions / Recommendations

As can be seen by the borescope images Alba Power unveiled significant damage to both units at Hardwoods. The unit at Stephenville should be inspected regularly to measure the growth of the highlighted items for strategic planning of future repair requirements. This unit would also benefit from compressor washing as well as inspection of the fuel system.

Alba Power would recommend the following options at Hardwoods, all of which Alba Power will supply a quote for separately;

- Unit A
    - This unit should be removed from service as soon as possible, at present this is a health and safety risk as well as a risk to the parent material. The options for this unit are;
        - Exchange unit with Alba Power serviceable unit
        - Return unit to Alba Power for light repair concentrating on;
            - Turbine blade replacement
            - Combustion can repair
            - Inspection of all other components, rebuild test and return
        - Full overhaul at Alba Power

- Unit B
    - This unit has a significant item missing with the remainder of the stators creeping with risk of further loss and catastrophic failure. The unit should have the following works completed;
        - On site top half lift and replacement parts fitted

Alba Power believes we can assist greatly and will quote accordingly. Alba Power will apply best practise to ensure the client has a fit for purpose repair while returning the unit to the client as swiftly as possible. As discussed we can complete these options immediately on request.

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7 Timesheets

ALBA POWER LTD

ALBA POWER

Payroll Daily Timesheet

Week ending :- 25 June 2007

Employee name :- C. Archibald

Day	Date	Location	~~Offshore~~ Onshore	Normal Time	O'Time x 1 1/2	O'Time x 2	Bonus	Description
Sun								
Mon								
Tue								
Wed	30 May 07.	Hardwoods. NFM.	11					Olympus Borescope.
Thu	31 May 07	"						Unit Review + Start
Fri								
Sat								

Employee Signature :

Approved: [signature]

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ALBA POWER LTD

ALBA POWER

Payroll Daily Timesheet

Week ending :- 9 June

Employee name :- C. Archibald

Day	Date	Location	Offshore	Normal Time	O'Time x 1 1/2	O'Time x 2	Bonus	Description
Sun								
Mon								
Tue								
Wed	6 June 2007.	Stephenville.		12				Travel to Site.
Thu	7 June 2007.	Stephenville		10				Borescope of Olympus
Fri								
Sat								

Employee Signature : [signature]

Approved:

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ALBA POWER LTD

Payroll Daily Timesheet

Week ending :- 2 June 2007   Employee name :- C. Smith

Day	Date	Location	Onshore	Offshore	Normal Time	O'Time @ x 1.5	O'Time @ x 2	Description
Sun								
Mon								
Tue								
Wed	30 May 07	Hardwoods. NFM.	11					Olympus Borescope.
Thu	31 May 07.	"						Unit Replacement Start
Fri								
Sat								
TOTALS:								

Employee Signature :

Approved:

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Scotland

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Fax: (44) 01569 730099
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ALBA POWER LTD

Payroll Daily Timesheet

Week ending :- 9 June

Employee name :- Colin Smith

Day	Date	Location	Offshore	Normal Time	O'Time x 1 1/2	O Time x 2	Bonus	Description
Sun								
Mon								
Tue								
Wed	6 June 2007	Stephenville		12				Travel to Site
Thu	7 June 2007.	Stephenville		10				Borescope of Olympus
Fri								
Sat								

Employee Signature :

Approved:

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8 Future personnel requirements

Human Resources and Social Development Canada | Ressources humaines et Développement social Canada | Canada

Foreign Worker Quick Links:

Foreign Worker Home Page | Go

Employing foreign workers can be an essential part of a company's business strategy. Foreign workers can fill labour shortages in Canada and bring new skills and knowledge to help the country's economy grow.

HIRING STEPS :

In almost all cases, foreign workers must have a valid work permit to work in Canada. When hiring a foreign worker, you, the employer must generally :

1. Submit an HRSDC Foreign Worker Application for a labour market opinion (LMO) to the Service Canada Centre responsible for your area.

   Before confirming a job offer, HRSDC considers whether :

   - The job offer is genuine;
   - The wages and working conditions are comparable to those offered to Canadians working in the occupation;
   - Employers conducted reasonable efforts to hire or train Canadians for the job;

   NEW: Hiring Temporary Foreign Workers for Occupations under Pressure

   In some regions, and depending on the circumstances/time, labour market information may indicate that the demand for labour in certain specific occupations is greater than the available supply. To meet the pressing human resource needs of employers, Human Resources and Social Development Canada (HRSDC) and Service Canada (SC) have developed Regional Lists of Occupations under Pressure. For occupations found on these lists, employers will not be required to undertake lengthy or comprehensive advertising efforts before being eligible to apply to hire a foreign worker.

   For more information, please visit:

   - Hiring Temporary Foreign Workers for Occupations under Pressure
   - News Release

   - The foreign worker is filling a labour shortage;
   - The employment of the foreign worker will directly create new job opportunities or help retain jobs for Canadians;
   - The foreign worker will transfer new skills and knowledge to Canadians; and
   - The hiring of the foreign worker will not affect a labour disputes or the employment of any Canadian worker involved in such a dispute.

   Learn more about the HRSDC LMO assessment criteria, noting that a Quebec Acceptance Certificate (CAQ) issued by the province is also required for jobs in Quebec.

2. Once HRSDC approves the job offer, send a copy of the HRSDC LMO confirmation letter to the foreign worker.

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3. Inform the foreign worker to apply for a work permit from Citizenship and Immigration Canada (CIC).

Next, CIC decides whether the foreign worker will get a work permit according to the requirements to work and reside temporarily in Canada.

SPECIAL CONDITIONS :

Under the *Immigration and Refugee Protection Act (IRPA)*, there are special cases when employers do not need an HRSDC labour market opinion to hire a foreign worker, and/or the foreign worker may not need a Citizenship and Immigration Canada (CIC) work permit.

- Learn about occupations that are exempt from the HRSDC labour market opinion.
- Learn about occupations that are exempt from the CIC work permit.

Also, please note that special criteria apply for employers hiring foreign workers in some industry sectors and occupations including :

- Academics
- Seasonal Agriculture
- Film and Entertainment
- Information Technology
- Live-in-caregivers
- Pilot Project for Occupations requiring a high school Diploma or Job-specific Training

LOCATION	ADDRESS	PHONE	FAX
St. John's	P.O. Box 8548 223 Churchill Avenue Pleasantville St. John's, Newfoundland A1B 3P3	(709)-772-2982	(709)-772-6442

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9 WHSCC approval

WHSCC

146-148 Forest Road • P.O. Box 9000 • St. John's, NL • Canada • A1A 3B8
Telephone: (709).778-1000 • Toll Free 1.800.563.9000 • Fax (709).778-1110 • www.whscc.nf.ca

ASSESSMENT SERVICES DEPARTMENT

FAX: 709 778 1110

MAY 29 2007

FAX: 709 536 4104

NEWFOUNDLAND POWER INC
Attn: John Budgell
P O BOX 8910
ST JOHN'S NL A1B 3P6

CERTIFICATE OF CLEARANCE

TO: NEWFOUNDLAND POWER INC

RE: ALBA POWER LIMITED

REQUEST PURPOSE: On Going Work - Current Year

This certifies that the above referenced employer has complied with both the reporting and payment requirements of the Workplace Health, Safety and Compensation Act of Newfoundland and Labrador and is in good standing with the Commission as of today's date.

This certificate expires 45 days from the date of issue. If the above stated purpose has not been satisfied by the expiration date of this certificate, we recommend that you request an additional certificate to protect your business from any potential assessment liability related to this employer.

If you have any questions, please call me at 709 778 1198 or you may use our toll free number noted above if calling within Newfoundland and Labrador.

Sincerely,

Sandra Follett
Enquiry Clerk

L26

APPENDIX 5
HYDRO INSPECTION SHEETS
HARDWOODS AND STEPHENVILLE

APPENDIX 5
HYDRO INSPECTION SHEETS
HARDWOODS AND STEPHENVILLE

HYDRO
THE POWER OF
COMMITMENT

2003-06-10 Rev-01

GAS TURBINE
OPERATOR'S DAILY INSPECTIONS
UNIT & ASSOCIATED EQUIPMENT

1. **CONTROL MODULE**
   a. P C (alarms, printer, paper, etc.)
   b. MCC's (lights, bkr's, on/off, etc.)
   c. AVR (inverter, charger, batteries, etc.)
   d. Inergen fire system (fire panel, pressures, etc.)
   e. Check kwhr meters, lights, etc.
   f. Building lighting and general safety check.
   g. Building heating/air conditioning.

2. **FUEL FORWARDING MODULE**
   a. Forwarding pumps (leaks, pressure, temperature, flow, etc.)
   b. Filter/Coalescer (leaks, pressure across filter, etc.)
   c. Inergen fire system (fire panel, pressures, etc.)
   d. Lighting, heating, vents, etc.
   e. Sump drains, etc.

3. **A & B MODULES**

   GAS GENERATORS
   a. Fuel leaks (lines, fittings, gauges, valves, etc.)
   b. Air leaks (starter, lines, etc.)
   c. GG Oil (levels, leaks, heater, fittings, valves, etc.)
   d. Electrical connections.
   e. Sump drains

   POWER TURBINES
   a. Oil leaks (lines, clutch module, etc.)
   b. Blankets and thermocouples (burnt indication, etc.)
   c. Bearing supports (leaks, wear, etc.)
   d. Bellows assembly (security of attachment, cracks in flanges & volute, etc.)

   GENERAL
   a. Lighting.
   b. Heaters.
   c. Coolant leaks.

4. ALTERNATOR MODULE

a. Jacking pumps (leaks, gauges, pressure switches, etc.)
b. Exciter area (burn marks, etc.)
c. Bearing supports (leaks, wear, etc.)
d. Lighting.

5. AUXILIARY MODULE

a. Pumps (leaks, pressure, etc.)
b. Demister & evacuator (leaks, etc.)
c. MLO system (temperature, pressure, leaks, etc.)
d. Glycol system (temperature, pressure, leaks, etc.)
e. Inergen fire system (fire panel, pressure, etc.)
f. Lighting.

COMPRESSES AIR SYSTEM
a. Air leaks (lines safety valves, unloaders, etc.)
b. Compressor oil (level, color, etc.)
c. Dryer & receiver tanks (leaks, etc.)

GLYCOL SYSTEM
a. Coolant (leaks, temperature, etc.)
b. Heat exchangers (fans, belts, guards, motors, etc)

MISCELLANEOUS
a. Sump level
b. Yard fencing (signs, holes, etc.)
c. Tank farm (piping, leaks, vegetation, etc.)
d. Security (check back gate, fence, etc)

6. FUEL OFF-LOADING MODULE

a. Building (fuel leaks, lighting, heating, vents, etc.)
b. Inergen fire system (fire panel, pressure, etc.)
c. Varec guage________m. Oil temperature______ F.

7. MAINTENANCE BUILDING

a. Building (general condition, lighting, security, etc.)
b. Water supply (hot/cold water, leaks, etc.)

8. TERMINAL STATION

a. Building (lighting, heating, water, etc.)
b. Recorder – frequency/mw/mvar (check date, time, paper, etc.)
c. Security (fire door closed, etc.)
d. Alarms.

9. REMARKS

____
____
____
____

HYDRO
THE POWER OF COMMITMENT

2003-03-03 Rev 01

GAS TURBINE
UNIT & ASSOCIATED EQUIPMENT
OPERATOR'S WEEKLY INSPECTIONS

Date: ______________________ Inspected By: ____________________________

The following areas and associated items must be visually inspected each week:

GAS GENERATION

Inlet Plenum A:

____Bird Screens
____Filter Assembly

Inlet Plenum B:

____Bird Screens
____Filter Assembly

Jet Engine A:

____Leaks (Fuel, Oil, Air)
____Drain Sump
____Heaters
____Clean up Fuel & Oil Drippings

Jet Engine B:

____Leaks (Fuel, Oil, Air)
____Drain Sump
____Heaters
____Clean up Fuel & Oil Drippings

Power Turbine A:
____Bellows (Cracks)
____Volute Expansion Joint
____Thermocouples
____Bearing Supports
____Blankets

Power Turbine B:
____Bellows (Cracks)
____Volute Expansion Joint
____Thermocouples
____Bearing Supports
____Blankets

Exhaust A:
____Exhaust Stack (Gen. Cond.)
____Snow Door Pneumatics

Exhaust B:
____Exhaust Stack (Gen. Cond.)
____Snow Door Pneumatics

Clutch A:
____Oil Leaks
____Grounding Brush
____Clean up Oil Drippings

Clutch B:
____Oil Leaks
____Grounding Brush
____Clean up Oil Drippings

ELECTRICAL GENERATION

Generator

____Temperature (Stator & Air)
____Heaters

Exciter

____Temperature (Air Out)
____General Condition

SWITCHGEAR

____General Interior & Exterior Condition
____Station Service Transformer Temp. (Press F4 on DCS)
____Heaters
____Weatherproof (leaks)

CONTROL SYSTEMS

____Indicating Lights
____Inverter
____AVR
____Recorders
____Battery Chargers
____Alarms

FUEL SYSTEM

____Leaks
____Fuel Pressures & Temperatures
____Drains
____Pumps & Valves
____Dip Fuel Tanks as per GAP Regulations.
(Complete Fuel Inventory & Reconciliation Forms and Compare to Tank Gauge & Recorder). F5
NOTE: The first working day of each month forward end of month fuel readings to the Production Supervisor.

COMPRESSED AIR SYSTEM

____Leaks (Oil & Air)
____Air Dryer Condition
____Drain Water Trap
____Indicating Lights

LUBE OIL SYSTEM

____Pumps (Including Jacking)
____Leaks
____Fans/Evacuator/Demister/Etc.
____Pressure Switches & Gauges

COOLING SYSTEMS

____Glycol Leaks
____Regulators
____Pumps (Noise)
____Fans (Belts/Guards/ Etc.)
____Temperatures
____General Exterior Condition

FIRE PROTECTION SYSTEM

____Energen System Pressures
____Accessibility
____Identified
____Panel/Alarms
____CO2 System Pressures
____Accessibility
____Identified

BUILDING & PROPERTY

____Building Water Supply
____Security System
____Sump Levels
____Heating Systems
____House Keeping
____Tank Farm Dyke
____Pump out Water in Dyke
____General Condition of Building

HYDRO
THE POWER OF COMMITMENT

2003-04-17 Rev 01

SEMI-ANNUAL INSPECTIONS

GAS TURBINE

1. Inlet plenum A & B
2. Gas generator A & B
3. Power turbine A & B
4. Exhaust A & B
5. Clutch A & B
6. Fuel forwarding and off-loading
7. Jacking pumps
8. Demister
9. Vent fan
10. Main oil pumps
11. Main oil tank
12. Glycol system
13. Alternator
14. Sump and dykes
15. Fire protection system
16. Air system
17. Battery systems
18. Battery system check sheets (III, V, VI)

GAS TURBINE
UNIT & ASSOCIATED EQUIPEMENT
SEMI-ANNUAL INSPECTION

DATE:________________ INSPECTED BY:__________________________

<u>Inlet Plenum A:</u>

1. Check condition of bird screens, plenum floor, walls, etc. Remarks: _________

____

2. Check condition of monoclones, fans & ductwork for cracks & check ladders for security.

Remarks: ____

____

3. Check condition of inlet filters: Remarks: ___________________________

____

4. Inspect and check operation of blow-in-doors for freedom of movement and

Operation of alarm limit switches. Remarks: ____________________________

____

5. Check operation of pressure differential switch for inlet filters, check that tubing is not plugged, etc. Remarks: ______________________________

6. Check inlet compartment for loose objects and foreign materials, and outside doors are sealed with no leaks. Remarks: ______________________________

____

7. Check the inlet temperature thermocouple reading on computer with a digital thermometer held next to thermocouple probe. Remarks: ______________________________

____

8. Check louvers for freedom of movement, etc, on enclosure fans 1 & 2 GGA.

Remarks: ______________________________

Inlet Plenum B.

1. Check condition of bird screens, plenum floor, walls, etc. Remarks: __________

____

2. Check condition of monoclones, fans & ductwork for cracks & check ladders for security.

Remarks: ______________________________

____

3. Check condition of inlet filters: Remarks: ______________________________

____

4. Inspect and check operation of blow-in-doors for freedom of movement and operation of alarm limit switches in control room. Remarks: ______________________

____

5. Check operation of pressure differential switch for inlet filters, check that tubing is not plugged, etc. Remarks: ______________________________

6. Check inlet compartment for loose objects and foreign materials, and outside doors are sealed with no leaks. Remarks: ______________________________

____

7. Check the inlet temperature thermocouple reading on computer with a digital thermometer held next to thermocouple probe. Remarks: ______________________

____

8. Check louvers for freedom of movement, etc. on enclosure fans 1 & 2 GGB

Remarks: ____

Gas Generator A:

1. Inspect the five chip detectors for metallic deposits (refer to C.W. Manual, volume 111 7.2.1.2-14) Remarks: ______________________________

____

2. Check for cracks in nose bullet. Remarks: ______________________________

3. Clean entry guide vanes and inspect with extension light and mirror. If indication of cracks, investigate using dye penetrate procedure. Also inspect the first stage compressor shrouded stators (refer to C.W. Manual, Volume 111 7.2.1.2/1-3) Remarks: ______________________________

____

4. Drain and refill the air starter with 150cc.(5oz.) of clean generator lubricating oil. Remarks: ______________________________

5. Inspect the ignition units and igniter plugs. Check for security of connections and any physical damage. Remarks: ______________________________

____

6. Check all fuel, oil and airlines for condition and security of connections. Remarks:______________________________

7. Inspect and lubricate the fuel pressure regulator (LF-4) shaft and check for leaks. Remarks: ______________________________

8. Inspect liquid fuel valve and actuator for loose bolts, oil leaks, wear, binding and security of mounting. Remarks: ______________________________

9. Remove the air system strainer screen (ST-CA-1) Inspect and clean, check the air regulating system components for leaks, cleanliness, etc. Remarks: ______________

____

10. Inspect and lubricate the fuel fire valve plunger rod to assure freedom of operation.

Remarks: ______________________________

11. Check the security of the supplementary fuel pump/motor assembly. Check the supplementary fuel filter indicator. Clean/change filter if required. Remarks: ________

____

12. Check all junction boxes for security of terminals, tidiness, overheating, etc.

Remarks: ____

13. Inspect combustion chamber outer casing general condition. Inspect the engine to power turbine bellows for dents, distortion, hot spots, etc.
Remarks:____

14. Check lube oil tank level using the dipstick level indicator. Top up as required.
Remarks:____

15. Check that the drainage hole is clear and free. Remarks:____________________

16. Check forced air heaters, lubricate motors if required.
Remarks:______________________________

<u>Gas Generator B</u>

1. Inspect the five chip detectors for metallic deposits (refer to C.W. Manual, Volume 111 7.2.1.2-14) Remarks: ______________________________

____

2. Check for cracks in nose bullet. Remarks : ______________________

3. Clean entry guide vanes and inspect with extension light and mirror. If indication of cracks, investigate using dye penetrate procedure. Also inspect the first stage compressor shrouded stators (refer to C.W. Manual, Volume 111 7.2.1.2/1-3) Remarks: ____

____

4. Drain and refill the starter with 150 cc.(5 oz.) clean generator lubricating oil.

Remarks: ____

5. Inspect the ignition units and igniter plugs. Check for security of connections and any physical damage. Remarks: ______________________________

6. Check all fuel, oil, and airlines for condition and security of connections.

Remarks: ____

7. Inspect and lubricate the fuel pressure regulator (LF-4) shaft and check for leaks.

Remarks: ____

8. Inspect liquid fuel valve and actuator for loose bolts, oil leaks, wear binding and security of mounting. Remarks: ______________________________

9. Remove air system strainer screen (ST-CA-1) Inspect and clean, check the air regulating system components for leaks, cleanliness, etc. Remarks: ____________

____

10. Inspect and lubricate the fire fuel valve plunger rod to assure freedom of operation.

Remarks: ____

11. Check the security of the supplementary fuel pump/motor assembly. Check the supplementary fuel filter indicator. Clean/change filter if required. Remarks: ________

____

12. Check all junction boxes for security of terminals, tidiness, overheating, etc.

Remarks: ____

13. Inspect combustion chamber outer casing general condition. Inspect the engine to power turbine bellows for dents, distortion, hot spots, etc.
Remarks:____

14. Check lube oil tank level using the dipstick level indicator. Top up as required. Remarks:____________________

15. Check that the drainage hole is clear and free. Remarks:____________________

16. Check forced air heaters in modules, lubricate motors if required. Remarks:____________________

Power Turbine A:

1. Check the security of thermocouple terminations, etc.

Remarks: ____________________

2. Inspect the power turbine cover blankets for general condition.

Remarks: ____________________

3. Check vibration detectors security of pickup and connections.

Remarks: ____________________

4. Inspect the front and rear bearing supports for oil seepage at covers. Check all hold down bolts, etc. Remarks: ____________________

5. Inspect the exhaust volute general condition, mount supports and load reference indication (refer to C.W. Operation & Maintenance Manual, Section 2.2.2.2) Remarks:

____

6. Inspect the inside of the power turbine volute for falling objects, cracks, loose or defective deflector rings, etc.

a) 1 Inspect bolts for evidence of any bolt movement, broken wire or broken tac weld.
b) Remove and discard any bolts showing signs of being dislodged.
c) Clean threaded bolt holes.
d) Clean existing tac weld material.
e) Install new bolts to recommended torque of 90 +/- 5 in-lb (see attached service bulletin), (use washers only if they were supplied with the bolts when they were purchased).
f) Reinstall all lock wires.
g) Put a small tac weld between the head of each bolt and the ring.
h) Put the tac weld between the deflector ring and the casing.

Remarks:_______________________

Power Turbine B:

1. Check the security of thermocouple terminations, etc. Remarks: ___________

____

2. Inspect the power turbine cover blankets for general condition. Remarks: _____

____

3. Check the vibration detectors security of pickup and connections. Remarks: ___

____

4. Inspect front & rear bearing supports for oil seepage at covers. Check all hold down bolts, etc. Remarks: ____

5. Inspect exhaust volute general condition, mount supports & load reference indication (refer to C.W. Operation & Maintenance Manual, section 2.2.2.2) Remarks:

____

5. Inspect the inside of the power turbine volute for falling objects, cracks, loose or defective deflector rings, etc. Remarks: ______________________________

Exhaust A:

1. Check the exhaust stack inside wall panels for security of insulation, plates, etc. Remarks; ____

2. Check snow doors and cylinders for ease of operation, lubricate as required. Check operation of limit switches, wiring, air leaks, etc. Remarks:

____

Exhaust B:

1. Check the exhaust stack inside wall panels for security of insulation, plates etc.

Remarks: ____

2. Check snow doors and cylinders for ease of operation, lubricate as required. Check operation of limit switches, wiring, air leaks, etc. Remarks:

____

Clutch A:

1. Check the clutch box base hold down bolts. Inspect grounding brush. Remarks:

____

Clutch B:

1. Check the clutch box base hold down bolts. Inspect grounding brush. Remarks:

____

Fuel forwarding & off-loading:

1. Check the filter vessels, heater vessel, etc. for fuel leaks. Note: Fuel temperature:_________ and Pressure:___________.
   Remarks____

2. Check fuel forwarding and off-loading pumps for leaks, etc. grease as required.
   Remarks:____

3. Check fuel flow meters for leaks, etc.
   Remarks:____

4. Lubricate all manual valves as required.
   Remarks:____

5. Check diesel generator tank for leaks, level etc.
   Remarks____

6. Check turbine oil storage for leaks, etc.
   Remarks:____

7. Check that the drainage hole is free and clear.
   Remarks:______________________________________

Jacking Pumps:

1. Check motor brushes. Remarks: ____________________________

2. Check operation pressures & shaft lift (both ends) with a dial indicator.
Note:

The following motors must be on prior to performing this test Evacuator, Demister,

MLO pump & Jacking Pump. Remarks:____________________________

____

3. Check pump and fittings for leaks. Check hold down bolts & grease motor

bearings if required. Remarks:

____

Demister:

1. Inspect mounting hardware, hose and connections. Check for oil leaks, vibration
etc. Remarks: _____

____

2. Clean/change filter as required. Remarks: ________________________

Vent Fan:

1. Check mounting bolts, fan, fan coupling, louver free to move, etc. Remarks:

____

Main Oil Pumps:

1. Check for oil leaks, pressure and general condition. Grease bearings as required.

Remarks: ____

2. Check brushes DC motors. Remarks: ________________________________

Main oil Tank:

1. Drain condensation from main tank. Use valve at bottom of tank. Remarks: ___

____

2. Check level of oil in tank,(dipstick) add as required. Remarks: ______________

____

Glycol system:

1. Check cooling fans pitch angle settings & general condition of blades. Remarks:

____

2. Check tightness & condition of belts. Remarks: __________________________

3. Lubricate all manual valves, flow control valves, etc. and grease bearings as required.

Remarks: ____

4. Check for leaks, and check expansion tank glycol level. Make note of tank level. Check low level alarm switch. Remarks:

____

5. Drain off some glycol and check contamination content and protection level. Remarks:____

6. Check heat exchanger cooling tubes and vanes for leaks, rust, etc. Remarks:

____

7. Check the condition and operation of the three-way thermostat. (lubricate all moving parts)

Remarks: ____

Alternator:

1. Check condition of filters. Remarks: ______________________________

2. Check filter block switch, (check hose is not let go or pinched) Remarks: _____

____

3. Check alternator louvers, make sure they are free to move. Remarks: _________

____

4. Check alternator anti-condensation heaters, load readings, etc. Remarks:

____

5. Check doors and ladders for security.
Remarks:____

6. Check earth fault indication brush. Remarks______________________________

Sump & Dykes:

1. Check level of fluid in sump. Operate level switch to get alarm in control room.

Arrange to have sump pumped out if close to level switch. Remarks:________________

____

2. Check drain valve main tank for water & dirt contamination. Remarks ________

____

3. Check and grease all fuel valve stems, & associated equipment. Remarks: _____

____

4. Check steps to tank and hand rails (over dyke) for security etc. Remarks: ______

____

5. Check steps & handrail on tank for security etc. Remarks: __________________

____

6. Check tank sides, roof, & associated piping for excessive rust, etc. Remarks:

____

7. Check for debris & weeds inside dyke. Remarks: _________________________

____

8. Check to make sure no liner in dyke is exposed. Remarks: __________________

____

9. Check varec gauge for freedom of movement, reading compares with fuel dips.

Remarks: ____

10. Check lighting tank farm.(operate photo cell for lighting.) Remarks: _________

____

11. Check fuel lines, expansion joints, etc., for leaks, rust, etc. Remarks ________

____

FIRE PROTECTION SYSTEM
SEMI-ANNUAL INSPECTIONS

The following checks should be preformed during an Inergen system inspection:

1. Visually inspect area to verify it has not changed, look for blocked open doors or dampers, new equipment, etc.
2. Check detectors to make certain they are in place, not damaged or coated with dirt grease, paint or any contamination.
3. Check all manual pull stations, make sure they are not blocked from use.
4. Check all alarm devices for damage, dirt or corrosion.
5. Check piping is secure and nozzles are in place and not covered with dirt, etc.
6. Verify all pressure switches are in place and in the non-operated position.
7. Visually verify control panel is functioning properly. Power light on, no alarms.
8. Check each cylinder indicator gauge to determine that the cylinder pressure is in the operable range. (Green) Record pressure.

Inergen Fire Systems:

End A Module	Cylinder Pressure	____	____	____	____	____	____
Aux. Module	Cylinder Pressure	____	____	____	____	____	____
End B Module	Cylinder Pressure	____	____	____	____	____	____
Exciter Module	Cylinder Pressure		____	____			
Control Module	Cylinder Pressure		____	____			
Fuel Forward Module	Cylinder Pressure		____	____	____	____	
Fuel Off-loading Module	Cylinder Pressure		____	____	____	____	

Remarks:____

____

NOTES:____

COMPRESSOR/DRYER/ AIR SYSTEM
Semi-annual inspection
Station________________ **Date**____________________ **Name**________________

DEW POINT TEMP: ______ °C AMBIENT TEMPERATURE: __________ °C

	COMP. #1	COMP. #2	DRYER
Counter			
Replace Pre-Filter			
Replace After-Filter			
Clean Unloader Valve			
Change Desiccant (if required)			
Changed Base Oil			
Moisture Discharge			
High Temperature Alarm			
Oil Level Alarm			
Motor Amps			
Check Safety Relief Valves			

FUNCTION TEST SYSTEM:
Lead Comp. #1: Cut In ______ Cut Out _____ Running Time ______
Lead Comp. #2: Cut In ______ Cut Out _____ Running Time ______
Lag Comp. Pressure Switch Cut In ______ Cut Out _____
High Side: High Pressure Alarm: ____________Low Pressure Alarm: ____________
Low Side: High Pressure Alarm: ____________Low Pressure Alarm: ____________
Differential Pressure: ____________15 min Pressure Drop: ____________

CHECKS COMPLETED:

______ Check/clean outlet and purge check valve assemblies
______ Check/clean inlet & purge exhaust switching valves
______ Check oil relief valves, check valves, and pressure gauges
______ Check belt drives for tension and wear
______Check dryer failure alarm
______ Check for oil & air leaks in the system
______ Check guards/couplers
____ Check/clean the re-pressurization valve
____Check limit switches, and flow switches operation
____ Operate storage tank relief valves
____ Check all motor contactors,wiring,and bearing
____ Check thermostats & all electrical controls
___Check pressure drop across prefilter & afterfilter
___ Check flex connections

CAUTION: Before inspection and maintenance of the compressor, be sure to shut off starting switch .

Note Any Concerns Below:

____
____

BATTERY BANK SEMI-ANNUAL INSPECTIONS
(Liberty 2000 Sulfuric Acid, sealed.)

DATE:________________ INSPECTED BY:____________________

Bus Voltage:_____________V.DC Bus Amperage:_________________Amps.

Pilot Cell No.______________ Voltage Pilot Cell.______________V. DC

Position Found Float:_________ Equalize___________________________

Position left, Float:___________ Equalize___________________________

_______Check each cell for cracks, corrosion on terminals, leaks and swelling.
_______Clean, lubricate and tighten battery connections if needed.
_______Check the operation of ventilation fans and thermostat.
_______Check the operation of emergency lighting.

Only if Required:

_______Complete capacity (discharge) test of battery bank.
_______Conduct resistance test of cell-cell connections.(form VI)
_______Collect cell internal ohmic values. (form III)
_______Conduct individual cell temperature and voltage test. (form V)

Remarks:____

DIESEL GENERATOR CHARGER & BATTERIES

Bus Voltage: _____________ V. DC Bus Amperage: ____________ Amps.

Position Found Float: _______ Equalize : ________________

Position Left, Float: _________ Equalize: _________________

_______Check each battery for cracks, corrosion on terminals, leaks and swelling.
_______Clean, lubricate and tighten battery connections if needed.

Remarks: ____

Turn on fuel at day tank, fuel forwarding module, to start Diesel, run for a few minutes, shut down Diesel, turn off fuel at day tank.

Remarks: ____

Form III- VRLA Battery Cell Inspection

Manufacturer________________________ Serial #____________________________
Readings By________________________ Date______________________________

Cell No.	Impedance	Conductance	Resistance	Cell No.	Impedance	Conductance	Resistance
1				31			
2				32			
3				33			
4				34			
5				35			
6				36			
7				37			
8				38			
9				39			
10				40			
11				41			
12				42			
13				43			
14				44			
15				45			
16				46			
17				47			
18				48			
19				49			
20				50			
21				51			
22				52			
23				53			
24				54			
25				55			
26				56			
27				57			
28				58			
29				59			
30				60			

Form V- Battery Cell Inspection

Manufacturer________________________ Serial #__________________________

Readings By________________________ Date__________________________

Cell No.	Voltage	Temp (°C)	Cell No.	Voltage	Temp (°C)	Cell No.	Voltage	Temp (°C)
1			21			41		
2			22			42		
3			23			43		
4			24			44		
5			25			45		
6			26			46		
7			27			47		
8			28			48		
9			29			49		
10			30			50		
11			31			51		
12			32			52		
13			33			53		
14			34			54		
15			35			55		
16			36			56		
17			37			57		
18			38			58		
19			39			59		
20			40			60		

Table 1: Take temperature readings at the negative terminal of cells.

Form VI- Battery Cell Inspection

Manufacturer____________________ Serial #____________________
Readings By____________________ Date____________________

Clean & re-torque any connections with high resistance readings

Meter Probes Between Cell Posts	As-Found (Micro-Ohms)	As-Left (Micro-ohms)	Meter Probes Between Cell Posts	As-Found (Micro-Ohms)	As-Left (Micro-Ohms)
Lug & No. 1			30 – 31		
1 – 2			31 – 32		
2 – 3			32 – 33		
3 – 4			33 – 34		
4 – 5			34 – 35		
5 – 6			35 – 36		
6 – 7			36 – 37		
7 – 8			37 – 38		
8 – 9			38 – 39		
9 – 10			39 – 40		
10 – 11			40 – 41		
11 – 12			41 – 42		
12 – 13			42 – 43		
13 – 14			43 – 44		
14 – 15			44 – 45		
15 – 16			45 – 46		
16 – 17			46 – 47		
17 – 18			47 – 48		
18 – 19			48 – 49		
19 – 20			49 – 50		
20 – 21			50 – 51		
21 – 22			51 – 52		
22 – 23			52 – 53		
23 – 24			53 – 54		
24 – 25			54 – 55		
25 – 26			55 – 56		
26 – 27			56 – 57		
27 – 28			57 – 58		
28 – 29			58 – 59		
29 – 30			59 - 60		
			No. 60 & lug		

HYDRO
THE POWER OF
COMMITMENT

2005-02-15 Rev 02

GAS TURBINES
ANNUAL INSPECTUONS

1. Take oil samples from GGA, GGB, MLO.

2. Complete a tool inventory.

3. Complete a spill control inventory.

4. Check Sump Level Indicators/Switch.

5. Check Operation of Fuel Level Switches.
(SVLGT Only)

HYDRO
THE POWER OF COMMITMENT

2005-03-30 Rev 02

GAS TURBINE

5 Year Inspections

These inspections will be completed on a 5 year interval :

1. Change all lube oil filters.
2. Change all fuel filters.
3. Change all air filters.
4. Check IRD Vibraction Equipment

Check all relevant equipment after changing filters.

HYDRO
THE POWER OF COMMITMENT

2003-06-10 Rev 01

Gas Turbine

P&C 6 year inspections

These items are to be inspected on a 6 year interval :

1. Relay trip 86 and 94.
2. Relay protection timers, elect/mech.
3. Relay protection timers, electronic.
4. Electronic protection relays.
5. Relays, elect/mech., C/V solenoid type.
6. Relays, elect/mech., C/V induction type.
7. Transducers.
8. Panel metering.
9. Metal-clad Switchgear.
10. Transformers.

HYDRO
THE POWER OF COMMITMENT

2003-06-10

METAL CLAD SWITCHGEAR

BEFORE OPERATING: Counter: ____________

DUCTOR TEST 100 A (micro ohms)
A Phase: ____________ B Phase: ____________ C Phase: ____________

Complete these tests only if instructed			
Timing Test	A	B	C
Close			
Trip			
Doble Test			
Inspect Arcing Chamber			

Command Current	
Close______________ Amps	Trip______________ Amps

CONTROL COIL RESISTANCE (ohms):
Trip: ____________ Close: ____________

MEGGER TEST 5 kV (breaker in open position):

A __________ Mega ohms B __________ Mega ohms C __________ Mega ohms

AFTER OPERATING: Counter: ____________

CHECKS COMPLETED:

______ Lubricate Control Block
______ Check Primary Connections
______ Check and lubricate latching pawl mechanism
______ Check erosion indicator, wipes and gaps
______ Perform vacuum interrupter integrity test

Gas Turbine Test Run (HWD & SVL)

Station: Date:

Local Operator:

ECC Operator:

Test Condition	Time	Load (MW) If Applicable	Successful Yes	Successful No	Alarms Yes	Alarms No	Trend Data Filed Yes	Trend Data Filed No
With unit shut down start GGA in Generate Mode and run to full load								
Maintain full load for 10 minutes								
Shut down GGA								
With unit shut down start GGB in Generate Mode and run to full load								
Maintain full load for 10 minutes								
Shut down GGB								
With unit shut down start GGA & GGB in Generate Mode and load to 10 MW (5 MW each end)								
Change MW and MVAR set points to verify functionality (Local & ECC)								
Switch to Sync Condense Mode and shut down GGA & GGB								
With unit in Sync Condense select GGA start and go to generate at 5 MW								
Select Sync Condense and shut down GGA								
With unit in Sync Condense select GGB start and go to generate at 5 MW								
Select Sync Condense and shut down GGB								
With unit in Sync Condense select GGA & GGB start and go to generate at 10 MW (5 MW each end)								

Print and file trend data for all tests.

Record all alarms and anomalies in the attached notes section.

Notes:

APPENDIX 6
REFURBISHMENT RECOMMENDATIONS COST ESTIMATE SPREADSHEET
HARDWOODS AND STEPHENVILLE

COST ESTIMATE SPREADSHEET No. 1
HARDWOODS GAS TURBINE FACILITY
REFURBISHMENT RECOMMENDATIONS

Newfoundland and Labrador Hydro
Stephenville and Hardwoods Gas Turbine Condition Assessment Study
NG Job No. 21061
Rev 1 ------ 2007-12-14

COST ESTIMATE SPREADSHEET No. 1
HARDWOODS GAS TURBINE REFURBISHMENT RECOMMENDATIONS

Item	Hardwoods Recommendations	Cost Total
1--	**Gas Generators / Power Turbines Equipment**	
1	Engine A assembly be removed, disassembled to allow for detailed internal inspection with major refurbishments as required (Report para. 5.2.1)	
	o S&S Turbines Cost to refurbish and test engine assembly in BC	$515,000.00
	o Cost to transport engine assembly to BC & back	3,200.00
	o Engine removal & reinstallation by S&S Turbines Technicians	14,000.00
2	Engine B assembly be removed, disassembled to allow for detailed internal inspection with major refurbishments as required (Report para. 5.2.1)	
	o S&S Turbines Cost to refurbish and test engine assembly in BC	$460,000.00
	o Cost to transport engine assembly to BC & back	3,200.00
	o Engine removal & reinstallation by S&S Turbines Technicians	14,000.00
3	Inspect the Power Turbine assemblies A & B in detail upon removal of 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

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	

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**

COST ESTIMATE SPREADSHEET No. 2
STEPHENVILLE GAS TURBINE FACILITY
REFURBISHMENT RECOMMENDATIONS

Newfoundland and Labrador Hydro
Stephenville and Hardwoods Gas Turbine Condition Assessment Study
NG Job No. 21061
Rev 1 ------ 2007-12-14

COST ESTIMATE SPREADSHEET No. 2
STEPHENVILLE GAS TURBINE REFURBISHMENT RECOMMENDATIONS

Item	Stephenville Recommendations	Cost Total
1--	**Gas Generators / Power Turbines Equipment**	
1	Engine A assembly be removed, disassembled to allow for detailed internal inspection with major refurbishments as required (Report para. 6.2.1)	
	o S&S Turbines Cost to refurbish and test engine assembly in BC	$505,000.00
	o Cost to transport engine assembly to BC & back	2,600.00
	o Engine removal & reinstallation by S&S Turbines Technicians	14,000.00
2	Engine B assembly be removed, disassembled to allow for detailed internal inspection with major refurbishments as required (Report para. 6.2.1)	
	o S&S Turbines Cost to refurbish and test engine assembly in BC	$350,000.00
	o Cost to transport engine assembly to BC & back	2,600.00
	o Engine removal & reinstallation by S&S Turbines Technicians	14,000.00
3	Inspect the Power Turbine assemblies A & B in detail upon removal of the Engines as noted in Items 1 & 2 to verify the mechanical integrity of the units. Inspect and refurbish the following: (Report para. 6.2.5)	$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. (Report para. 6.2.6)	$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. 6.2.2)		
	Quantity / **Device**		
	o Replace Ignition Exciters	$24,000.00	
	o Replace Speed Governors/fuel valve assemblies	$56,000.00	
8	**Option:**		
	S&S Turbines provides a rental engine for the period when an engine leaves site for refurbishment in BC until its return to site (estimated at 120 days per engine - assumes only one engine off-site at any time)		
	o 120 days per engine x 2 = 240 days (8 months)		
	o Fee for installation and removal = $14,000.00		
	o Monthly on-site rental fee = $2,450.00 x 8 = $19,600.00		
	o Fired hour charge = $42.00 per hour (Assume 60 hours in 8 months = $2,520.00)		
	o Return transport from/to BC = $5,200.00		
	Total:	$41,320.00	$1,142,520.00
2--	**Inlet Air Systems A & B**		
9	Interior of both Inlet Air Plenums A and B and silencers be sand blasted and recoated (Report para. 6.2.3)	$ 18,000	
10	The concrete slab of Air Plenums A & B be cleaned, prepared and coated with breathable masonry paint (Report para. 6.2.3)	$ 1,800	

11	Re-align the inlet bellmouth assembly on Engine B	$5,000	
	(Report para. 6.2.3)		
12	Replace the rubber sealing strips around the exterior door in Inlet	$ 1,500	
	Air Plenum A (Report para. 6.2.3)		
13	Complete following items regarding the access doors to both Air		
	Plenum structures: (Report para. 6.2.3)		
	o Sand blast and coat all areas corroded under the access doors	$ 700	
	o Weld new plates inside the troughts	$ 600	
	o Replace the weather stripping on the access doors	$ 1,000	
	o Install a new drip cap over both access doors		
		$ 3,400	
14	Replace grating on platforms attached to both Air Plenum structures		
	(Report para: 6.2.3)		
15	Install new 42" high handrail with kick plates around the perimeter	$ 2,200	
	of the top of each Air Plenum structure. (Report para. 6.2.3)		
16	Weld new plates with proper size holes to existing structures to	$ 500	
	prevent pullout of bolts during lifting. (Report para. 6.2.3)		$ 34,700
3--	**Exhaust Stacks A & B**		
17	Install kick plates along with additional top rails to extend the height	$ 2,000	
	of the existing handrails to 42" on the platforms attached to both		
	Exhaust Stacks (Report para. 6.2.4)		
18	Replace metal mesh floor grating on the Exhaust Stacks	$ 3,400	
	platforms with standard bar grating (Report para. 6.2.4)		
19	Replace existing access hatches on the Exhaust Stacks with	$ 16,500	
	operable man doors with proper flashings and weather stripping		
	(Report para. 6.2.4)		
20	Modify existing snow door access platforms to support new ladders	$ 15,000	

	that will provide operators with better access to inspect the snow		$ 36,900
	doors (Report para. 6.2.4).		
4--	**Glycol Cooler for Main Lube Oil**		
21	Refurbish Glycol Cooler for Main Lube Oil as follows:		
	(Report para. 6.2.9)		
	o Replace bottom section of the heat exchanger	$ 3,500	
	o Replace the canopy cladding and re-coat the entire structure	$ 4,000	
	o Clean Tubes in Heat Exchanger to remove surface coating of	$2,500	
	grey substance.		$ 10,000
5--	**Gas Generator / Power Turbine Enclosures A & B**		
22	Interior of both Gas Generator / Power Turbine Modules A and B be cleaned, areas with corrosion sandblasted and the interior of the Modules be re-coated. (Report para. 6.2.10)	$ 11,000	
23	Replace or modify the railings on top of the Gas Generator / Power Turbine Modules for safety reasons. The new railings should be 42" high with a handrail, mid-rail and kick-plate. (Report para. 6.2.10)	$ 500	
24	Modify the existing man doors to both Power Turbine Modules to have inspection windows added. (Report para. 6.2.10)	$ 1,600	
25	Add an additional top rail to the handrail on the stair landing for the Gas Generator / Power Turbine Modules to extend the height to 42" and add kick plates to the bottom of the handrails. All for safety reasons. (Report para. 6.2.10)	$ 1,500	
26	Weld new plates with proper size holes to existing structures to	$ 3,700	
	prevent pullout of bolts during lifting. (Report para. 6.2.10)		$ 18,300
6--	**Fire Detection and Protection**		
27	Install an Inergen fire suppression system in the Control Building	$45,000	

		(Report para. 6.2.11)			45000
7--		**Alternator & Excitation System**			
28		Conduct Electrical Tests on the Alternator and Exciter while in its	$7,000.00		
		enclosure to determine condition as follows: (Report para. 6.3.3)			
		o Alternator Stator EL-CID Test			
		o Alternator Stator Polarization Index Test			
		o Alternator Stator Partial Discharge Test			
		o Alternator Rotor Megger Test - 500 vdc			
		o Measure Alternator Rotor Winding Resistance			
		o Rotating Exciter Stator and Rotor Megger Tests			
		o Measure Rotating Exciter Stator and Rotor Winding Resistance			
29		Remove & replace the Alternator from its Enclosure and remove the rotor fo	$50,000.00		
		for complete visual inspection of the stator / rotor / exciter. Inspections			
		shall include: (Report para. 6.3.3)			
		Stator Inspection to include but not limited to:			
		o Loose or damaged Wedges			
		o Loose or cracked or failed winding connections			
		o Dusting, greasing and other signs of windings movement			
		o Indications of arcing (hot spots) and damaged core laminations			
		o Loose core bolts			
		o Signs of corrosion, contamination and excessive dirt			
		Rotor Inspection to include but not limited to:			
		o Signs of physical damage			
		o Loose or cracked or failed winding connectors			
		o Slot wedge migration and possible contact with retaining rings			
		o Signs of overheating			
		o Loose rotor wedges			
		o Dye penetrant examinations and magnetic particle tests on			
		forgings; retaining rings and fan components to detect			
		fatigue cracks.			
		Bearings Inspection to include but not limited to:			

	o Assess general condition of the bearings		
	o Determine if the bearings require re-babbiting or machining.		
30	Carry out refurbishment work as required following following		
	completion of electrical tests (Item 27) and visual inspections.		
	(Item 28). Estimate includes:		
	o Rewind of stator at supplier's shop	$1,200,000.00	
	o Rewind of rotor c/w new end caps and overspeed testing at	$800,000.00	
	supplier's shop		
	o Rewind /refurbishment of exciter	$25,000.00	
	o Transport costs to/from supplier's shop - assume UK	$30,000.00	
31	Perform a trim balance on the rotor to address the vibration issue	$10,000.00	
	observed physically and noted on the vibration monitoring system.		
32	Replace the AVR control system with an ABB Unitrol F Series	$225,000.00	
	System as was done at Hardwoods. (Report para. 6.3.4)		$2,347,000.00
8--	**Alternator Enclosure**		
33	Install 42" handrails on the north and south sides of the alternator	$ 1,500	
	enclosure roof for fall protection purposes. (Report para. 6.3.7)		
34	Add inspection windows to the man doors in the alternator module	$ 1,600	
	for safety purposes. (Report para. 6.3.7)		
35	Add an additional top rail on the handrails on the stair landings for	$500	
	the alternator module to increase the height of the handrails to 42"		
	for safety purposes. As well kickplates should be added to the		
	bottom of the handrails. (Report para. 6.3.7)		$ 3,600
9--	**Alternator Air Cooling System & Glycol Cooler**		
36	Glycol Cooler be refurbished as follows: (Report para. 6.3.8)		
	o Heat exchanger support system be re-coated	$ 9,500	
	o Remove existing cladding and replace with heavy guage steel	$ 5,500	

	o Seal weld all joints between the cladding and structural framing	$	4,400		
	o Clean the tubes and external fins to remove the build up of the grey dust coating.		$2,500		21900
10--	**Fuel oil System**				
37	Re-weld and re-coat 3 rungs at the top of the ladder on storage tank 35b. (Report para. 6.4.1)	$	750		
38	Raise the top of the north dyke wall to the same elevation as the other 3 walls. Suggest adding an access stairs on the north wall of the dyke to prevent slope deterioration from pedestrian traffic accessing the dyke interior. (Report para. 6.4.1)	$	14,000		
39	Re-tighten the clamps around all concrete pilasters with caulking applied where required. (Report para. 6.4.1)	$	5,000		
40	Conduct an investigation to determine if the joint between the concrete block, surrounding the oil transfer piping entering the ground in the northwest corner of the dyke, and the containment liner is adequately sealed. (Report para. 6.4.1)				
41	HYDRO to install new piping between the fuel forwarding facility and the Gas Turbine in a properly designed/environmentally acceptable trench. (Report para. 6.4.3)			$	19,750
11--	**Electrical Systems**				
42	Recommended that HYDRO consider conduct an Arc Flash Study of all electrical power equipment - switchgear; motor control centres, etc for safety reasons (personnel protection). (Report para. 6.5.1)		$5,000		
43	Recommended that HYDRO develop a back-up plan to cater for a 13.8 kV Switchgear breaker failure. (Report para. 6.5.1)				
	o Spare 13.8 kV circuit breaker (common to both sites)		$60,000		

44	Install a rain shield at the air vent on the 13.8 kV Switchgear Building	$2,500	
	to prevent the ingress of rain and snow. (Report para. 6.5.1)		
45	Replace the following Power Tronic Battery Chargers as the existing		
	Chargers are no longer supported by the supplier. (Report para. 6.5.5)		
	o 125 Volt dc Battery Charger	$14,000	
	o 250 Volt dc Battery Charger	$21,000	
46	Recommendation for HYDRO to prepare a replacement program and	$21,000	
	budget to replace over time the electro-mechanical generator		
	protection relays with digital relays. (Report para. 6.5.6)		
47	Replace the 15 kV power cable supplying the 750 kVA Station Service	$6,100	
	Transformer. (Report para. 6.5.7)		$129,600
12--	**Control & Instrumentation Systems**		
48	Replace faulty input channel modules in the ELSAG Bailey INFI 90	8000	
	DCS System. (Report para. 6.6.1)		
49	Replace the existing DCS System interface computer (PC) with a new	4500	
	PC with the latest PCV and QNX software. (Report para. 6.6.1)	8000	
50	Replace the existing obsolete DCS power supply system with a new	24000	
	power supply. (Report para. 6.6.1)		
51	Due to hot and humid conditions in the Control Building, it is	1000	
	recommended that an air conditioning unit be installed in the area of		
	the DCS equipment. (Report para. 6.6.1)		
52	Replace the obsolete vibration monitoring system. (Report para. 6.6.3)	20000	
53	Make a number of junction boxes on the exterior of the Gas Turbines	2000	
	water-tight by installing a weather tight box over each existing box.		
	In addition, corroded terminal blocks in various junction boxes		
	should be replaced at earliest opportunity. (Report para. 6.6.8)		

54		Relocate the on-engine electrical junction boxes off the engines to		$1,500		
		isolate the terminations from vibration and heat. (Report para. 6.6.8)				69000
13--		**Buildings**				
55		Control Building Refurbishments: (Report para. 6.7.1)				
		o Replace cladding and roofing on the Control Building within next	$	28,000		
		5 years.				
		o In addition, exterior wood fascia on windows should be painted.	$	600		
		o For safety reasons, install intermediate steps on the existing	$	1,100		
		steps up to the floor area containing the control and power				
		distribution equipment..				
		o For safety reasons, support or fasten down a steel cover for an	$	6,500		
		exterior electrical trench at the rear of the Building.				
56		Fuel Forwarding Building Refurbishments: (Report para. 6.7.2)				
		o Relocate the bleed valve used to remove air from the truck unloading	$	1,700		
		system from its present location to over the concrete containment				
		dyke to prevent any diesel fuel released through the operation of				
		the valve from falling on the ground.				
		o Pave the area surrounding the off-loading containment dyke to	$	2,500		
		facilitate the clean up of any spills.				
		o Replace the badly corroded gutters and downspouts on the Building	$	500		
		o Replace the cladding on the west Building wall in the next year	$	5,800		
		and the remainder of the cladding and roofing within the next 5 years.				
		o Install additional air intake louvres and ducting to convey incoming	$	6,000		
		air to the foundation level and install an additional or larger exhaust				
		fan on the opposite wall to provide better air movement in the				
		Building.				
57		Parts Storage Shed Refurbishments: (Report para. 6.7.3)				
		o Replace asphalt shingles in next 5 to 7 years	$	3,200		
		o Replace existing overhead door with a new commercial grade	$	1,800		
		door complete with proper weather stripping.				
		o Replace existing man door with a new commercial grade door	$	1,500		
		complete with proper weather stripping.				
		o Replace brackets on ladder with new ones.	$	300		

58	Waste Oil Storage Shed Refurbishments: (Report para. 6.7.4)		
	o Replace existing shed with a new non-combustible structure such as a new steel transportation container.	$ 7,900	
	o Relocate the new structure to inside the oil storage containment dyke area.	$ 7,000	74400
14--	**Miscellaneous Work on Ongoing Operational Issues**		
59	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:		4202670
	HYDRO labour & overhead costs for Items A - M at 8% of Sub-total:		336213.6
	TOTAL:		**4538883.6**

COST ESTIMATE SPREADSHEET No. 3
HARDWOODS & STEPHENVILLE GAS TURBINE FACILITIES
MAJOR EQUIPMENT REPLACEMENT OPTIONS

Newfoundland and Labrador Hydro
Stephenville and Hardwoods Gas Turbine Condition Assessment Study
NG Job No. 21061
Rev 1 ------ 2007-12-14

COST ESTIMATE SPREADSHEET No. 3

HARDWOODS & STEPHENVILLE GAS TURBINES MAJOR EQUIPMENT REPLACEMENT OPTIONS

Item	Major Equipment Options	Cost Total
1--	**New Gas Turbine to replace entire existing GT at one site**	$35.000,000.00
	(Report para. 7.4)	
	o New 50 MW GT c/w synchronous condenser capability	
	o Includes all new mechanical auxiliary equipment	
	o New fuel forwarding module	
	o New Air Compressor Package	
	o New lube oil system	
	o Includes all new electrical auxiliary equipment	
	o New 13.8 kV switchgear / motor control centres / batteries&chargers / digital protection relays / bus duct / cabling / motors	
	o New station service transformer	
	o Includes all new control & instrumentation auxiliary equipment	
	o New DCS Control System	
	o New vibration monitoring system	
	o New temperature monitoring system	
	o New Instrumentation Devices throughout	
	o Requires a new concrete foundation for GT	
	o Includes installation and commissioning	
	o Allowance for HYDRO engineering staff involvement in new gas turbine procurement and installation.	400,000.00
	Sub-Total:	**$35,400,000.00**
	o Allowance for Dismantling the existing Gas Turbine and the Demolition of surplus buildings and structures	**$1,500,000.00**
	Total:	**$36,900,000.00**

	o Retain existing fuel oil storage tanks and truck unloading equipment	
	o Retain existing step up transformer	
	o Review role of existing buildings at each site	
	o Requires new physical location at site (old GT not removed)	
2--	**New alternator and rotating exciter at one site**	
	(Report para. 7.3.2)	
	o Purchase new alternator and exciter c/w new AVR	$2,500,000.00
	o Top mounted standard air filter house	$300,000.00
	o Acoustic and weather protection canopy	$250,000.00
	o Installation & Commissioning (estimate)	$750,000.00
	o Transportation Costs	$75,000.00
	o Interface costs to existing infrastructure & auxiliary systems (estimate)	$1,000,000.00
	o Carry out other refurbishment work at each site in accordance with	$2,288,381.00
	Spreadsheets No. 1 and 2 (See Report para. 7.3.2)	
	Total:	**$7,163,381.00**
3--	**New gas generators (engines) and power turbines for one site**	
	(MAN TURBO Proposal -- $Cdn) (Report para. 7.3.1)	
	o Purchase 2 new gas generators & 2 new power turbines	$20,900,000.00
	o Transportation to site	200,000.00
	o Erection and Commissioning	2,000,000.00
	o Carry out other refurbishment work at each site in accordance with	$3,319,761.00
	Spreadsheets No. 1 and 2 (See Report para. 7.3.1)	
	Sub-Total:	**$26,419,761.00**
	o Modifications to existing engine/power turbine enclosures as required	To be advised
	to accommodate new equipment	pending further study
	Total:	**To be Advised**
4--	**Rental of temporary mobile gas turbines for one site**	

		(To provide required MW and MVAR service while alternator is being		
		refurbished or replaced) (Report para. 7.5)		
	(i)	**o Pratt & Whitney 25 MW MobilePac gas turbine (4 month rental)**		
		o Transportation to Site from Europe		$625,000.00
		o Site Set up Fee		150,000.00
		o HV Connection		50,000.00
		o Fuel Connection		7,500.00
		o Monthly Rental = $400,000 per month		1,600,000.00
		o Full Time Supervisor = $25,000 per month		100,000.00
		o Site Dismantle Fee		150,000.00
		o Transportation Back to Europe		625,000.00
			Total:	**$3,307,500.00**
	(ii)	**o Caterpillar 5 MW gas turbine (4 month rental)**		
		o Rent 5 machines = 25 MW capacity		
		o Monthly rental cost (capacity charge) per gas turbine = $105,000		$2,100,000.00
		o Fired Hours Charge per gas turbine = $42.00 per hour		$42,000.00
		(Assume 1000 hour total for 4 months)		
		o Mobilization & Consumables Cost per gas turbine = $16,000		$80,000.00
		o Setup, Commissioning & Test per gas turbine = $106,000		$530,000.00
		o Decommissioning per gas turbine = $48,500		$242,500.00
		o Full Time Site Supervisor at $10,000 per month		$40,000.00
			Sub-Total:	$3,034,500.00
		o Connect 5 machines to existing 13.8 kV circuit breaker		$50,000.00
		and step-up transformer (estimate)		
		o Connect existing fuel line to rental GT's		$7,500.00
			Total:	**$3,092,000.00**
5--		**Dynamic Var Compensator at Hardwoods Site only**		
		(To replace the Hardwoods Gas Turbine) (Report para. 7.6)		
		o High level ballpark estimate		$10,000,000.00
		o Purchase new 30 MVAR dynamic var compensator equipment		
		o Includes civil site costs - preparation & concrete works		
		o Includes terminal station bus work		
		o Retain existing 13.8 / 138 kV step-up transformer		

		o Retain existing 13.8 kV switchgear assembly										
		o Dismantling costs of existing gas turbine										
		This is a ballpark estimate only. If HYDRO is interested in pursuing this option										
		an indepth study with involvement by a D-VAR supplier is required to										
		investigate the application of this technology at the site, define scope and confirm costs.										

APPENDIX 7
MAN TURBO NEW ENGINES AND POWER TURBINES PROPOSAL

Hearn, Bill G.

Subject: FW: 50 MW Gas Turbine Generator/Synchronous Condenser

Attachments: N&G_TechQuotation.pdf; Ref_FT8(worldwide).pdf; FT8 Power Key to Plant Upgrade.pdf; Integration of 25MW gt into existing power Station.pdf; MOBILEPAC.pdf; Mobile Power Paper1.doc; Two containerized 22.8 MW TM2500 gt powered gensets.jpg; FT8MobilePac_PEi (Oct2007).pdf

From: Pierre Bovon [mailto:Pierre.Bovon@manturbo-us.com]
Sent: Friday, November 02, 2007 2:28 PM
To: King, Brian
Subject: RE: 50 MW Gas Turbine Generator/Synchronous Condenser

Hello Brian,

As per our discussions, we understand that the tasks at hand can be split into basically 4 steps:

1. Provide replacement FT-8 engines for the existing Curtis-Wright gas turbines located at the Hardwood station. We can offer 2 x FT8-30 gas turbines designed for Diesel fuel, on baseplates, complete with auxiliary systems such as lube-oil system, CAB-system, standstill dryer, fire and CO2 protection, control panel, MCC, etc... Excluded are filter house, exhaust system, acoustic enclosure, or modifications thereof, dual fuel system with water injection, generator/synchronous condenser with auxiliaries, SSS couplings, etc... For this scope, we would estimate a cost of approx US$ 15 million for the US portion, plus Euro 5 million, for the European portion, FOB European port. Erection and commissioning would obviously depend on the local conditions, but we would estimate somewhere in the US$ 2 million range. See attached Technical Quotation.
2. The same would apply to Stephenville, unless you decide to use the gas turbines you pulled out from Hardwood as a source of spares to keep the currently installed units running at the Stephenville station. We would also point out that to our knowledge there is a second-hand market for parts for these engines which were used extensively used on war ships like destroyers and frigates.
3. At both stations, while back-up interim power is available (see point 4 below), Brush would have plenty of time to inspect and overhaul the installed generator/synchronous condenser and put them back into service. Or a replacement unit could be supplied for Hardwood to permit this same unit moved to Stephenville after overhaul.
4. Provide interim power at the Hardwood site for the duration of the upgrading work to be a carried out on the current power station. The same unit(s) could then be moved to Stephenville during the upgrading of that station. As you can see from the attached documents, standard portable stand-by gensets are readily available for sale, or may be even for rental, from Pratt & Whitney (FT-8) or from GE (LM 2500). MAN TURBO would not necessarily get involved in this aspect of the project. A number of documents dealing with these mobile units are attached.

We trust you will understand that if this develops into a concrete project, MAN TURBO would like to be given a chance to participate, and that we are currently quoting and executing similar projects in other parts of the world, as can be seen from the various attachments.
Hopefully the attached information will be useful for the time being.

Kind regards, Pierre

Pierre L. Bovon

MAN TURBO, Calgary
Suite 700,
1816 Crowchild Trail NW
Calgary, AB, T2M 3Y7

Tel. (403) 233-7151

Fax (403) 220-1389

E-mail: pierre.bovon@ca.manturbo.com or pierre.bovon@manturbo-us.com

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From: King, Brian [mailto:Brian.King@stantec.com]
Sent: Wednesday, October 24, 2007 12:26 PM
To: Pierre Bovon
Subject: RE: 50 MW Gas Turbine Generator/Synchronous Condenser

Thanks for this up-date Pierre, and for your voice-mail earlier today. We too are talking with Brush to see what options we can explore for repairing/replacing the alternators. There is an important point to note: the alternator at Stephenville is slightly longer than the one at Hardwoods! This is to cater to the use of a glycol/water mix to cool the alternator at Stephenville, and this calls for increased surface in the alternator air path.

There is another concern that will effect selection of a particular option, and that is the duration of alternator down-time. It may not be practical to implement repairs to the existing units because the power distribution system needs their availability almost daily. It is therefore important to know how much it would cost to install a new unit and retain the existing plant. The operating philosophy would be to monitor the condition of the insulation in the existing units and to use them for synchronous condenser operation. The new units could be more conventional turbo-gen sets that are permanently coupled. They could be operated as synchronous condensers but with the penalty of wasted energy for driving the power turbine as a windmill. This type of operation would only be necessary to cover the time needed to up-grade and reinstate the old alternators.

Regards, Brian

From: Pierre Bovon [mailto:Pierre.Bovon@manturbo-us.com]
Sent: Tuesday, October 23, 2007 6:15 PM
To: King, Brian
Subject: FW: 50 MW Gas Turbine Generator/Synchronous Condenser

Hello Brian,

We have contacted Brush who supplied the original generator/synchronous condenser around 1975 (see drawing attached). Here is the technical information they provided.

BDAX8-280 13.8kV/3/60Hz
53.84MW/63.34MVA 0.85PF 3600rpm
ANSIC50.13 15 Deg C Air Inlet
2 off Double End Drive

Turbine Rating

-10 Deg F - 58.8MW
0 Deg F - 58.8MW
10 Deg F - 58.8MW
20 Deg F - 58.8MW
40 Deg F - 56.2MW
59 Deg F - 53.84MW
80 Deg F - 50MW
90 Deg F - 48MW

Suitable for -23 Deg C cold start

Supplied for use with SSS Clutch type 208T, with housings?

Design / size of machine we would now supply is different but we could offer a "interchangeable" / replacement unit.

MAN TURBO is of the opinion that replacement may not be necessary and that an overhaul may be sufficient. According to our experience, these electric machines are subject to much less wear than a GT, and that upgrading of the insulation and other minor repair may be sufficient to keep the unit running for years.

I will try to get a ball park figure for the replacement for you.

Kind regards, Pierre

Pierre L. Bovon

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E-mail: pierre.bovon@ca.manturbo.com or pierre.bovon@manturbo-us.com

From: Pierre Bovon
Sent: Thursday, October 18, 2007 11:19 AM
To: 'King, Brian'
Subject: RE: 50 MW Gas Turbine Generator/Synchronous Condenser

Hello Brian,

I acknowledge receipt of your huge file which I could not pass on as received. I sent it on to Germany by CD.
I will however attempt to give you some useful information for now.
Technical:
As I explained to you, the FT-8 may be quite suitable as a replacement for these Curtiss Wright machines. Without in-depth investigation, we cannot tell so far whether the current acoustic enclosure and the exhaust housing could be modified to accommodate this substitution. We understand that the new units would have to be installed starting at both end from the SSS coupling. A somewhat similar solution was proposed for another installation (OLKILUOTO, see drawing enclosed), where spacer shafts were installed at one end, and where exhaust channels were built to the chimneys. As another example, you will find the drawing of the installation FINNJET, which was a retrofit of an FT-8 in place of an FT-4.
Commercial:
We can advance the following rough estimates: 2 x FT8-30 gas turbines designed for Diesel fuel, on baseplates, complete with auxiliary systems such as lube-oil system, standstill dryer, fire and CO2 protection, control panel, MCC, etc... without filter house, exhaust system, acoustic enclosure, or modifications thereof, we would count with a cost of approx US$ 24 million, FOB European port. Erection and commissioning would obviously depend on the local conditions, but we would estimate somewhere in the US$ 2 million range.
Current deliveries are quite long, probably in the range of about 18 months ex-works.

I hope the above information is useful for the current level of estimates that you have to prepare. If you require additional data, please do not hesitate to came back to me.

Kind regards, Pierre

Pierre L. Bovon

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E-mail: pierre.bovon@ca.manturbo.com or pierre.bovon@manturbo-us.com

From: King, Brian [mailto:bking@NGNS.com]
Sent: Friday, September 28, 2007 11:59 AM
To: Pierre Bovon
Subject: FW: 50 MW Gas Turbine Generator/Synchronous Condenser

From: King, Brian
Sent: Friday, September 28, 2007 10:58 AM
To: 'pierrebovon@manturbo.com'
Subject: FW: 50 MW Gas Turbine Generator/Synchronous Condenser

This is a repeat of previous attempts to e-mail you.
Brian

From: King, Brian
Sent: Friday, September 07, 2007 4:27 PM
To: 'pierrebovon@ca.manturbo.com'
Subject: 50 MW Gas Turbine Generator/Synchronous Condenser

Pierre Bovon,
Thanks for your offer of help on this topic. The attachment is the Curtiss Wright Manual for the Hardwoods site that contains information on the Alternator, the general information is copied below. The existing plant has an Olympus C 25MW gas turbine fuelled with #2Fuel Oil, at each end of the Alternator. They are gas generators that feed into Curtiss Wright turbines, and these are connected through SSS Clutch mechanisms to the alternator.

My guess at the cost of replacement plant is in the region of $35million, what is your guess?
Regards

Brian King (bking@ngns.com)

First Name	:	Brian
Last Name	:	King
Organization Name	:	Neill and Gunter (Nova Scotia) Limited
Country	:	Canada
Email	:	bking@ngns.com
Keywords	:	50MW Peaking Plant
Comment	:	1.1 INTRODUCTION

Newfoundland and Labrador Hydro (HYDRO) is a utility which owns and operates facilities for the generation, transformation and distribution of electricity to utility, industrial and residential customers in the Province of Newfoundland and Labrador.

In the island interconnected grid, HYDRO has nine (9) hydro-electric generating plants with a total installed capacity of 980 MW and five (5) thermal generating plants with a total installed capacity of 626 MW. Two nominal 50MW gas turbine facilities provide peaking, emergency backup and synchronous condensing services. One facility is located at Stephenville, on the south west coast of the island of Newfoundland and the other is located at Hardwoods on the east coast near the City of St. John's.

2. DESCRIPTION

2.1 REQUIREMENT

The purpose of this request for a quotation is to provide HYDRO with a cost estimate that can be used as a basis in deciding the best course of action to achieve a high degree of operating reliability at least cost for the next 15 years at both the Hardwoods and Stephenville gas turbine plants. The output of the replacement plants should be as close to 50MW as the standard product line will achieve. Operation of the alternator as a synchronous condenser is an important feature of the required plant(s).

2.2. AVAILABLE INFORMATION

For information purposes some general information is being provided to assist Proponents in preparing proposals.

General:

Ambient conditions, 99% > -6degF, <80degF. 50ft ASL.

Technical Quotation

2 (two) FT8-36 Gas Turbine Sets
for
Hardwood Power Station

Neill and Gunter (Nova Scotia) Limited

Canada

MAN TURBO AG
Steinbrinkstraße 1
46145 Oberhausen
Germany

Project Manager: Norbert P. Faustmann
Dept.: SD3
Phone: +49-208-692-2475
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TABLE OF CONTENTS

1. IDENTIFICATION DATA

1.1 Background and Capabilities

In 2001, three powerful partners - GHH, BORSIG and SULZER – boasting over 180 years of experience of turbomachinery manufacture united under the MAN TURBO logo. The name is a byword for innovative know-how, commitment and creativity in the development and construction of pioneering products and technologies that set global standards, always in the service of our customers. We are thus at the forefront of international competition in this field.

Three legally autonomous core companies operate at four sites, each with their own production shops:

MAN TURBO AG
Oberhausen, Berlin, Hamburg and Deggendorf, Germany

MAN TURBO AG, Switzerland *(previously Sulzer Turbo AG),*
Zurich, Switzerland

MAN TURBO S.r.l. *(previously de Pretto-Escher Wyss, S.r.l.)*
de Pretto
Schio, Italy

The turbomachinery activities of the MAN Group are managed centrally for all three companies by MAN TURBO AG, Oberhausen-Sterkrade.

MAN TURBO offers the broadest product spectrum in the entire sector. These companies are distinguished by their high level of competence in the development and production of complete turbomachinery trains. In addition to compressors, MAN TURBO with its gas and steam turbines, and process expanders, offers a comprehensive range of prime movers, enabling our customers to obtain the sophisticated technology they require for a variety of applications from a single supplier.

MAN TURBO has taken over the steam turbine programme of B+V Industrietechnik GmbH (BVI), Hamburg in 2006. Also in 2006 MAN DWE (formerly Deggendorfer Werft und Eisenwerk GmbH), part of the MAN Group, was integrated in the MAN TURBO Group.

The MAN TURBO AG was converted into a joint stock company retroactively to July 01, 1999 and directly allocated to the MAN Group.
The former GHH BORSIG Turbomaschinen GmbH was founded as a merger of the turbomachinery divisions of MAN Gutehoffnungshütte AG of Oberhausen, and Deutsche Babcock-Borsig AG of Berlin on March 01, 1996.

Gas turbines have been included in the range of products since 1988 by absorbing the industrial gas turbine business of the French company Hispano-Suiza.

1.2 Gas turbine manufacturer

In 1990, the gas turbine product line was expanded by signing a cooperation agreement with Pratt & Whitney's subsidiary Pratt&Whitney Power Systems Inc. (formerly Turbo Power & Marine Systems Inc.) for developing, manufacturing, and servicing of the FT8 industrial gas turbine family. The FT8 combines most advanced technologies used in the aeroengine industry with the operating experience of well over 14,506 JT8D-type aircraft engines of Pratt & Whitney. An additional 30 years and more than 14 million operating hours of experience with the predecessor model FT4 have created a gas turbine for every application.

1.3 Gas turbine type

Based on the FT8 gas turbine MAN TURBO developed a „Modular Growing Standardized Power Station System" (MOGSPOSS) which allows to adapt a simple cycle power station to the customer's requirements of growing power requirements and improvement of efficiency by adding components as additional gas turbines.

1.4 Generator manufacturer

In the quotation are included only supplier of the two-pole generators. The generator plants are from BRUSH Electrical Machines Ltd. in Loughborough, England, UK, from Siemens AG in Erfurt, Germany, and from Jeumont Electric in Jeumont Cedex, France etc..

1.5 Engineering Consultant

The preferred engineering consultant of Fingrid Oy was the Finnish company ÅF-Enprima Ltd who acted for the reserve power plant project at Olkiluoto.

The other engineering consultant was also a Finnish company Poyry (formerly Electrowatt-Ekono) who acted for the emergency power plant project for Kraftnät Aland Ab at Ringsböle in the same function

1.6 FT8 Reference List

Attachments

Reference List FT8 Industrial Gas Turbine **(Later)**

1.7 FT8 Reference List – Installations by MAN TURBO AG

Attachments

Reference List FT8 Industrial Gas Turbine – Installations by MAN TURBO AG **(Later)**

1.8 Reference List FT8 TwinPac / SwiftPac 50

Attachments

- Reference List of FT8 TwinPac / SwiftPac 50 **(Later)**

1.9 Reference List FT8 TwinPac – Installations by MAN TURBO AG

Attachments

- Reference List of FT8 TwinPac – Installation by MAN TURBO AG **(Later)**
- FT8 TwinPac in Rheinberg/ Germany **(Later)**
- FT8 TwinPacs in Olkiluoto / Finland **(Later)**

2. GENERAL

2.1 Plant Description

On basis of our former project at Olkiluoto in Finland for a reserve power plant with a supplemental function as emergency power plant for the OL nuclear plants of TVO we are offering an indoor installation for replacing of Olympus gas turbines.

The base offer comprises of (2) two FT8-36 Gas Turbine Sets (25MW each)

MAN TURBO offers its 25 MW ISO rated gas turbine FT8-36 for power production. The FT8-36 gas turbine, designed for 60 Hz power generation via a direct driven synchronous generator, will be configured as a so-called „TwinPac", a configuration with two gas turbines driving a double-end generator. Together with the ancillary equipment, a completely self-contained package is formed, offering an outstanding efficiency in the 50 MW class gas turbine market segment.

Due to its aero-derivative design with fast start-up and quick loading capability, the FT8 industrial gas turbine is ideally suited for daily start and stop operation as well as for base load power generation, keeping the operating cost at a competitive level. The outstanding efficiency figures, based on the two-shaft design of the gas generator and the use of the latest developments in the aircraft industry, are maintained over a wide load range, making the FT8-36 TwinPac configuration a reliable and thus cost-advantageous solution for simple cycle power generation applications.

The Scope of Supply of the FT8-36 Gas Turbine Sets includes the skid-mounted gas turbine coupled to the generator on a separate baseframe, and all ancillary equipment required to form a complete package installation.

Load sharing capability is not included in the Scope of Supply as detailed information is necessary to investigate a suitable solution but can be offered at a later stage of the project if requested.

To meet the inquired noise restrictions an indoor installation is offered.

A more detailed description of the Scope of Supply and Services is contained in the following section.

2.2 Plant Layout

3. SCOPE OF SUPPLY AND SERVICES

The scope of supply includes two (2) FT8-36 Gas Turbine Sets.

The finally FT8-36 TwinPac consists of two FT8-36 gas turbine including auxiliary plant equipment and a synchronous generator with two shaft ends. The scope of supply includes the components and services listed below (listed per FT8-36 gas turbine and per Electrical generator):

3.1 Base frame with mounted FT8 gas turbine

GG8 gas generator with

- Bellmouth
- Fuel manifold, fuel nozzles
- Variable inlet guide vanes
- Variable stator vanes (stages 2 - 3)
- Compressor bleed valves
- Muscle air system for closing of bleed valves
- Auxiliary gear unit with starter motor
- Rotor speed sensors (2 x LP shaft, 3 x HP shaft)
- Vibration probe (1x LP casing)

PT8-36 power turbine with

- Rotor speed sensors (3 x)
- Vibration sensors (2 x PT8 casing)
- Diffuser section
- Exhaust collector box
- Output shaft with diaphragm couplings

Ignition system

Fuel system

- Shutoff valves
- Modulating valve
- Distribution system

Hydraulic system

Lube oil system piping and valves

Measuring transducers and transmitters

3.2 Lube oil skid for gas generator and power turbine

- Two 3-phase AC and one DC motor-driven pump
- Oil cooler
- Oil tank
- Heater
- Duplex filter

3.3 Starter skid (electro-hydraulic)

- One motor-driven hydraulic pump
- Filter
- Oil tank
- Heater

3.4 Inlet air system

- Air inlet plenum integrated in the gas turbine enclosure

3.5 Exhaust gas system

- Expansion joints
- Exhaust duct adapter

3.6 Set of interconnecting Piping

- Pipework (supplied loose), partially prefabricated, for interconnection of ancillary equipment with gas turbine

3.7 Gas turbine control panel

One in common for each TwinPac consisting of:

- three (3) sections with:

  Woodward MicroNet digital gas turbine controller,
  Bently Nevada accelerometer-based vibration monitoring System 3500,
  Siemens S7 programmable logic controller for sequencing and
  Siemens WIN-CC monitoring system with VDU-screen.

- two (2) marshalling sections with:

  terminal strips for all incoming and outgoing signal cables

The control panels of the gas turbines or/and the electrical generator, of the MCC distribution board and DC supply, and the control panel for the fire fighting and detection systems are to be housed direct in Customer's GT building or control room.

3.8 Engineering

- General arrangement drawing
- P&I diagrams
- Foundation size and load plans
- List of terminal points
- Cable plan
- Logic flow chart
- Terminal box wiring plan
- Control panel layout drawing
- List of electrical consumers
- Combined alarm and interlocking list
- Instrument list

3.9 Documentation

- 5 copies of the Operation and Maintenance Manuals

3.10 Test runs

Full-load test of gas generator

3.11 Options

Options marked with an "X" are included in the price.

X Standard combustion chamber

X Mobile compressor wash system (off-line)
(one per site or several gas turbines)

X Engine preservation system

. Gas fuel system

X Liquid fuel system

. Dual fuel system

X Gas fuel skid and filter system

X Liquid fuel skid with heater and filter skid

. Liquid fuel forwarding pumps and filtering skid

. Water injection skid and system

. Moisture separation system / Coalescer

. Self-cleaning air filter system (pulse type)

. Anti-icing system for inlet air system

- Static filter system (two stage)

- **Inlet air system**
  - Air intake duct between filter house and intake silencer
  - Intake silencer to meet a sound pressure level of 85 dB(A) according to EN ISO 3746 / ISO 6190 at 1m distance and 1.5m height above ground level

- **Indoor enclosure Gas turbine enclosure**
  - Sound insulation to meet a sound pressure level of 85 dB(A) according to EN ISO 3746 / ISO 6190 at 1m distance and 1.5m height above ground level
  - Indoor enclosure
  - Lighting system
  - Hand-operated lifting tackle
  - Ventilation system with sound insulation
  - Fire fighting system
  - Fire detection system

- **Fire - Control panel**
  - Control panel of wall-mounted type for fire fighting and detection systems of gas turbine enclosure

- **Electrical generator including ancillaries**
  - synchronous generator, double-end-driven
  - Neutral point cubicle
  - Line side cubicle
  - Cooling system

- **Electrical generator control panel**
  - Excitation system (AVR)
  - Generator protective equipment
  - Instrumentation
  - Synchronizing system

- **Electrical generator lube oil skid**
  - Duplex filter
  - Oil cooler
  - Two 3-phase AC and one DC motor-driven pump

- Oil tank with heater

- **Generator enclosure**
  - Sound insulation to meet a sound pressure level of 85 dB(A) according to EN ISO 3746 / ISO 6190 at 1m distance and 1.5m height above ground level
- Outdoor enclosure
- Container for gas turbine ancillary equipment
  (one for each gas turbine unit)
- Control container for outdoor installation
- Exhaust silencer to meet a sound pressure level of 85 dB(A) according to EN ISO 3746 and ISO 6190 at 1m distance and 1.5m height above ground level
- Silencers and enclosures to meet lower sound emissions
- Exhaust stack with 15m above ground level

X Motor Control Centre (MCC)
- MCC of withdrawable type for all electrical consumers in the scope of supply

X DC Battery System and Uninterruptable Power Supply (UPS)
- UPS and battery system for 230 VAC, 24/110/125 VDC power levels

- Load sharing capability for multiple engine configuration
- Set of interconnecting cables
  - Interconnecting MV-cable-material and LV-power and signal cable material (supplied loose / **max. straight length 50m**) within the confines of the scope
- SSS-clutch couplings for TwinPac
- Supervision of erection and commissioning by MAN TURBO personnel
- Erection and commissioning by MAN TURBO personnel
- Supervision of trial operation (72 hours) by MAN TURBO personnel
- Training of operators by commissioning staff
- Full owner staff training given at MAN TURBO's works (See separate quotation)
- Spare parts (See separate quotation)
- Special tools (See separate quotation)
- Rental pool agreement
  (gas generator, power turbine)
- Service/maintenance (See separate quotation)

<u>Option – Outside GT Base Scope</u> (See in Chapter 20)
- HI-FOG System
- Closed Cooling System
- Air Cooled Solutions

- Anti-Icing System with Exhaust and Sound Protection System
- Air Pressure Skid

3.12 Exclusions from supplies and services, requirements

All equipment and services not expressly mentioned in the foregoing sections are excluded and shall be provided free of costs by the Customer. Those supplies and services which are not part of our quotation include but are not limited to:

General

- All permits (e.g. planning permission), licences (e.g. approval of operation), and acceptance certificates levied by the authorities for the transport, construction and operation of the plant, unless specifically included in the scope of supply.
- All supply and return piping (fuel, injection water, drain, vent, ...) to and from the specified takeover points.
- External / internal (between skids) cables and cabling work to and from the specified takeover points including electrical connections
- The earthing system including connection to the equipment.
- Design and supply of foundations as well as all earthwork, brickwork, concrete and carpentry, cable trays.
- Industrial commissioning and other site activities (e.g. test run, acceptance test, performance test ...).

Specific for erection and commissioning

- **Site requirements and required services**

- A surfaced road connecting the jobsite to the nearest major road for the transportation of machine components.
- Suitable, compact area according to requirements on the works premises, near the jobsite for our construction facilities.
- The jobsite shall be secured.
- Supply of drinking water, service water and electrical power (220VAC, 63A)
- Provision of fluid system media in case hydrostatic tests are to be performed
- Liquid fuel
- Water for washing the compressor blading

- **Foundation requirements**

- Customer shall establish invariable axes and elevations approx. 3 weeks prior to start of the erection work.
- Grouting of anchor bolts/jacking plates with anti-shrinking compound (anchor bolts/jacking plates included in scope)

- Gauging of location of foundation internals and provision of gauging record approx. 3 weeks prior to start of erection work.
- All foundations ready for erection brushed clean and capable of absorbing full load, prior to the start of erection.

- **General requirements**

- Customer undertakes to inform our personnel on all obligations, notifications and similar with respect to local authorities, and to render all required assistance in dealings with such authorities.
- Time spent waiting for reasons not attributable to MAN TURBO shall be invoiced at the actual time of work on the basis of the valid MAN TURBO rates.
- Commissioning shall be performed without interruption immediately after completion of the erection operations, and is limited to three weeks. Testing of the complete plant to be performed by the Customer and MAN TURBO staff exceeding this time limit shall be invoiced at the actual time of work on the basis of the valid MAN TURBO rates, i.e. industrial machine start-up and surveillance during permanent operation shall be performed by the Customer.
- Qualified personnel for operating the plant up to the time of handing-over

4. BATTERY LIMITS OF LIQUID / GASEOUS MEDIA

Media to be supplied: =>
Return media to be drained, ventilated, etc: <=

Media =>	**GT combustion air**
Connection (supply)	Inlet Plenum of GT
Drawing no.	To follow
Media =>	**Ventilation air for GT encloure**
Connection (supply)	Entrance of base frame area of GT
Drawing no.	To follow

Media =>	**Natural Gas**
Specification	Fuel gas Doc. No. 10000082991
Connection (supply)	flange approx. 1m from GT-enclosure
P&I diagram no.	To follow
Mass flow (normal operation)	(refer to performance data)
min. pressure (DLN-base load)	31,4 bar (abs) 35,5 bar (abs)
max. pressure	42,4 bar (abs)
protection pressure	45,5 bar (abs)
min. temperature	20 K above dew point
max. temperature	149 °C
Media =>	**Liquid fuel**
Specification	Fuel acc. To Doc. No. 10000082993
Connection (supply)	flange at fuel forwarding skid
P&I diagram no.	To follow
Mass flow (normal operation)	(refer to performance data)
min. pressure	from 6m elevation about site location
max. pressure	4,5 bar (abs)
protection pressure	6,0 bar (abs)
min. temperature	Min. 15 K above cloud point
max. temperature	Min. 5 K below flash point and ≤ 70°C

Media =>	**Water for NOx reduction and GT compressor wash**
Specification	Demineralized water acc. to Doc. No. 10000082993
Connection (supply)	flange at injection skids and wash water tank on mobile wash trolley
P&I diagram no.	To follow
Mass flow (during washing)	(refer to performance data)
min. pressure	3 bar (g)
max. pressure	4.5 bar (g)
min. temperature	5 °C
max. temperature	70 °C

Media =>	**Lubricating and hydraulic oil**
Specification	
GT lube and hydraulic oil:	Doc.No.10000134443
GT starter hydraulic oil and	Doc.No.10000134445
electrical generator lube oil:	N.A.
Connection (supply)	Filling plugs of the oil tanks
P&I diagram no.	To follow

Media =>	**Water for air / oil cooler**
Specification	to follow
Connection (supply)	to follow
P&I diagram no.	to follow
Mass flow (approx.)	to follow
min. pressure	to follow
max. pressure	to follow
min. temperature	to follow
max. temperature	to follow
Media =>	**Water for evaporative cooler**
Specification (approx.)	0°dH (carbonate); 15-20 mS/m conductivity
Connection (supply)	flange at evaporative cooler system
P&I diagram no.	to follow
Volume flow (typical)	approx. 10m³/h per gas turbine
min. pressure	2 bar (abs)
max. pressure	to follow
min. temperature	to follow
max. temperature	to follow
Media =>	**Water for anti-icing (Glycol-system)**
Specification	to follow
Connection (supply)	flange of water/glycol heat exchanger
P&I diagram no.	to follow
Mass flow (approx.)	400 l/min per gas turbine
min. pressure	7 bar(g) (pumps supplied by MAN TURBO)
max. pressure	to follow
min. temperature	150°C
max. temperature	to follow

Media <=	**Water from air / oil cooler**
Specification	to follow
Connection (exit)	to follow
P&I diagram no.	to follow
Mass flow (approx.)	to follow
min. pressure	to follow
max. pressure	to follow
min. temperature	to follow
max. temperature	to follow

Media <=	**Waste Water of evaporative cooler**
Specification	to follow
Connection (exit)	flange at evaporative cooler system
P&I diagram no.	to follow
pressure	to follow
Media <=	**Water from anti-icing (Glycol-system)**
Specification	to follow
Connection (exit)	flange of water/glycol heat exchanger
P&I diagram no.	to follow
Mass flow (approx.)	400 l/min per gas turbine
pressure	6,5 - 7 bar (g)
temperature	0-150°C

Media <=	**Water (Drain)**
Specification	sewage to be lead into an oil carrying drain system
Connection (exit)	3 flanges of drain pipes at the GT-base frame
P&I diagram no.	To follow
Pressure	ambient pressure

Media =>	**Fire extinguishing system)**
Specification	N.A., Complete system for GT enclosure
P&I diagram no.	To follow

Media <=	**Ventilation air of GT enclosure**
Connection (exit)	Exit of base frame area of GT
Drawing no.	To follow

Media <=	**Exhaust Gas**
Connection (exit)	exit flange of exhaust collector box
Drawing no.	to follow (flange dimensions)
Mass flow (normal operation)	(refer to performance data)
Document no.	to follow (possible velocity/temp. distribution)
pressure	is determined by the pressure losses of the installations in the exhaust duct as for example exhaust silencer and stack
max backpressure	50 mbar
max. temperature	approx. 520°C at peak load and 40°C T_{amb}

Media <=	**Blow-off pipes**
Connection (exit)	Conducted to safe area (max length 3m)
P&I diagram no.	to follow

4.1 Battery limits of electrical and control systems

System	**Medium Voltage Power**
Connection	Generator terminals
Single line diagram no.	To follow

System	**Low Voltage Power**			
Power required				
FT8 TwinPac	Start	approx.	350	kW
(TEWAC without SSS clutches)	Anti-icing	approx.	(25)	kW
	Operation	approx.	190	kW
For details refer to the relevant	Aftercooling	approx.	110	kW
consumer lists	Standstill	approx.	60	kW
Motor Control Centre (MCC)				
Connection (input side)	terminal strips in incoming feeder cabinet			
Voltage required	400 VAC (3Phase)			
Tolerance required	+5/-10%			
Mounting	electrical room with air condition +5...30°C with raise floor			
Single line diagram no.	See in Chapter 14			
Battery station 125 V DC / Battery station 24 V DC				
Mounting	battery room with air condition +5...30°C			
Single line diagram no.	See in Chapter 14			
UPS - system 230 V 1Ph				
Mounting	battery room with air condition +5...30°C			
Single line diagram no.	See in Chapter 14			

System	**Instrumentation / Signals**
Connection	Terminal boxes/Terminal boards at components/skids/control cubicles
Diagram no.	Later

System	**Earthing**
Connection (to customers earthing system)	earth lugs at the base frame of the components
Diagram no.	to follow

5. PERFORMANCE DATA

Attachments

- Guarantee Data **(later)**
- LCP Annex VI – Gas Turbines **(later)**
- Expected Fuel Gas Pressure vs. Electrical Power Output **(later)**
- Performance Data **(later)**
- Consumer List FT8 TwinPac **(later)**
- Consumption List **(later)**
- FT8 TwinPac Start-up Profile (Normal Start) **(later)**
- FT8 TwinPac Start-up Profile (Black Start) **(later)**
- FT8 TwinPac Shut-down Profile Speeds
- FT8 TwinPac Emergency Shut-down Profile Speeds **(later)**
- Estimated Degradation of Power Output and Heat Rate at Continuous Load with Natural Gas Fuel after Compressor Wash **(later)**
- Estimated Degradation of Power Output and Heat Rate at Continuous Load with Fuel Oil No. 2 after Compressor Wash **(later)**
- Expected Shaft Power vs. Inlet Temperature **(later)**
- Heat Rate Correction Factor for Inlet Temperature **(later)**
- Correction Factor for Power Output and Mass Flow (Inlet & Exhaust) vs. Ambient Pressure **(later)**
- Correction Factor for Power Output and Mass Flow (Inlet & Exhaust) vs. Altitude **(later)**
- Relative Humidity Correction Factor for Power Output **(later)**
- Power Correction Factor for Inlet Temperature **(later)**

- Correction Factor for Power Output and Mass Flow (Inlet & Exhaust) vs. Altitude **(later)**
- Influence of Inlet Pressure Losses on Power, Heat Rate, Exhaust Mass Flow and Exhaust Gas Temperature relative to Base Load at ISO Conditions **(later)**
- Influence of Exhaust Pressure Losses on Power, Heat Rate, Exhaust Mass Flow and Exhaust Gas Temperature relative to Base Load at ISO Conditions **(later)**

6. OTHERS

Attachments

- Specification Gaseous Fuels FT8 Gas Turbines **(later)**
- Specification Water for Injection into Combustion Chamber FT8 Gas Turbines **(later)**
- Specification Liquid Fuels FT8 Gas Turbines **(later)**
- Specification Lube Oil **(later)**
- Specification Hydraulic Oil **(later)**
- Turbo-K Gas Turbine Compressor Cleaner **(later)**
- Sub Vendor List **(later)**
- Sound Power Calculation **(later)**
- Technical Description of Gas Turbine and Ancillaries **(later)**
- Painting Specification **(later)**

7. THERMAL AND MECHANICAL ENGINEERING

Attachments

- List of media **(later)**
- Data sheet for design of HVAC **(later)**
- Data sheet for design of drain systems **(later)**
- Data sheet for fire load **(later)**
- Industrialization JT8D-219 Air Engine FT8 Industrial Gas Turbine **(later)**
- FT8 Secondary Airflow and Lubrication Systems **(later)**
- Modular System **(later)**
- Gate Cycle Report - GT Report **(later)**
- Industrial Gas Turbine FT8
  Bill of Material FT8-30 Gas Turbine **(later)**
- System Engineering Gas Turbine FT8 **(later)**
- Instrument Gas Turbine Drawing No. 10000415327 **(later)**
- P&I Diagram Drawing No. 105369-00-01-B **(later)**
- Rohrleitungsliste Drawing No. 10000302523 **(later)**
- Vibration Monitor Checkout Procedures **(later)**
- Contoured Diaphragm Flexible Coupling Drawing No. 67R322-4888 **(later)**
- INSTALLATION AND MAINTENANCE MANUAL Power Transmission Couplings **(later)**

8. SCHEDULES, PROJECT ADMINISTRATION

8.1 Detailed schedule of the delivery

Attachment

- BAR CHART / BID - PLANNING: 30070xx.30 HARDWOOD POWER PLANT 2 x FT8-36 Gas Turbine Sets) **(later)**

8.2 DOCUMENTATION

Attachments

- Preliminary Drawing List GT-Generator Unit **(later)**

8.3 A description of the Supplier's project management system

Attachment

- Organization Chart for project execution **(later)**

8.4 Site Activities and Arrangements

Preliminary resource

Estimate 2-4, salaried employees and 8-21 workers per calendar month (Attachment Typical Installation of a Plant with 2x FT8-36 GT Sets) **(later)**

Need of site facilities

– office rooms	2 pcs. 12 - 14 m²
– outdoor storage area	1115 m²
– electric power (220 V) max.	60 kW

9. CIVIL ENGINEERING

Attachments

- Layout Drawing **(later)**
- Foundation Loading Drawing **(later)**
- Lateral Natural Frequencies **(later)**
- Erection Documentation OLKTwin 1/ 2 **(later)**

10. INSTRUMENTATION AND CONTROL

Attachments

- Control System Diagram FT8 PowerPac / TwinPac **(later)**
- FT8 TwinPac - Control System and Operation Modes **(later)**
- Speed PT Channel 3 Fault **(later)**
- Instrument List GT **(later)**
- Sequence Diagrams **(later)**
- Signal and Alarm List **(later)**
- GT UCP Layout **(later)**
- Specification Factory Acceptance Test UCP system **(later)**
- Overview Print of Visualisation System **(later)**
- GT Control Diagram **(later)**
- Functional Logic Description **(later)**

11. GENERATOR

Attachments

- BRUSH TURBOGENERATORS – DAX 2-Pole Turbogenerator **(later)**
- Fingrid Step Load and Off Load Estimates **(later)**

12. EXCITATION EQUIPMENT

Attachments

- Single line (Protection, Excitation and Synchronization System) **(later)**

13. GENERATOR PROTECTION, SYNCHRONISATION AND CONTROL

Attachments

- GCP - Generator Control Panel **(later)**

14. ELECTRICAL POWER EQUIPMENT

Attachments

- Overview Junction Boxes (GT) **(later)**
- Cable List Drawing No. 10000259260 **(later)**
- Motor Control Center ENERGON **(later)**
- LV Single Line Diagram **(later)**
- Uninterrupted Power Supply THYROTRONIC **(later)**
- Layout UPS **(later)**
- UPS Single Line Diagram **(later)**

15. DRAWINGS OF AUXILIARY PLANT COMPONENTS

Attachments

- Liquid Fuel Skid **(later)**
- Gas Fuel Skid **(later)**
- Lube Oil Unit Gas Turbine, Drawing No. 10000173647 **(later)**
- Plate Heat Exchanger (GT) **(later)**
- Oil Demister, Drawing No. 10000176150 **(later)**
- Dehumidifier - Assembly ML-420 **(later)**
- Lube Oil Filling Device, Drawing No. 10000178754 **(later)**
- Layout Mobiles Wash Skid, Drawing No. 10000014925 **(later)**
- Cold Air Buffer (CAB) **(later)**
- 2-Stage, 2-Side Static Filterhouse **(later)**
- Exhaust Stack with Silencer **(later)**

16. ELECTRICAL SYSTEMS - OUTSIDE GT BASE SCOPE

- General
- Power to grid system **(later)**

  - Generator busbar system
  - Generator breakers
  - Main transformer
  - Transformer over voltage and neutral point equipment
  - Transformer protection system

- Auxiliary transformer **(Later)**
- Building electrification **(Later)**

17. CONTINUOUS EMISSION MONITORING SYSTEM

INTRODUCTION

A complete system is offered for the continuous measurement of emissions of a GT Power station.
All necessary analysis equipment, auxiliaries services, piping, cabling, cabin modules, data acquisition system and services are included performing a turn-key by project.

All equipments offered are test approved by TÜV-Reinland and accepted by European & Spanish Authorities.

TECHNICAL DESCRIPTION

1. MAIN STARTING DATA

Stack expected emissions:

- Concentration SO2 < 500 mg/m3
- Concentration CO < 500 mg/m3
- Concentration NOx < 100 mg/m3
- Temperature: to be defined (< 500 °C)
- Flow: to be defined

Stack characteristic:

- Diameter: to be defined
- Thickness: to be defined
- Platform: to be defined

2. MEASURING COMPONENTS

Following ranges are proposed:

Components	Ranges
SO2	0 – 100 / 500 mg/m3
NO	0 – 25 / 0 - 100 mg/m3
CO	0 – 100 / 500 mg/m
CO	0 - 10 Vol
O_2	0 - 21 Vol %
Dust	0 – 200 mg/Nm^3
Flow	(Calculated) 0 – 50.000 Nm3/h

Temperature	0 – 600 °C
Absolute Pressure	800 -1.200 mbar

Note :

Other ranges are also possible.

3. SCOPE OF SUPPLY

3.1 Gas sampling and conditioning system. Including filtering and standard flanges.

3.2 Heated sample lines with heated tube PTFE. UV protection ∅ 45. Electrical connection 220 V Pt100. Output máx 90 VA/m. Máx. working temp. 20°C. Estimated length= 15 m.

3.3 Emission analyzer with:
Modular system S710 configuration holder 19", with following modules:

Multor: for measurement of components CO2, CO, NO, OXOR for measurement of O2.
Module UNOR: for measurement of components SO2.

Sample conditioning with cooling device, filter, and pumps.

Outdoor cabinet full equiped aprox: 2100 x 800 x 600 with air conditioned.
Power supply: 400 / 230V, 50 Hz

3.4 Dust Monitoring system by the method of light transmission SICK model OMD41 including purge and fail safe schutters. Weather protection.

3.5 Flow, pressure, temperature from stack.

Weather station (humidity, pres. Abs. and ambient temperature.

3.6.Data acquisition system
With: I/o modules to collect all analog/digital signals: Module DAS8000 (for 8 analog /digital signals) and communication modules DA4000 Communication Modules Modbus
2 x PC complete with printer
Software per emission control acc.to the national rules. Based on:

- Base dates Access
- Visual Basic

Software data treatment with:

- Viewer data

- Summary of medium values, ½ values and daily values for each component.

3.7 Set span Gas and Regulators with:

- Gas set span gas bottles & regulation devices.
- Gas certifications.

3.8 Installation of all equipments considering that the CEMS container with be located at the bottom of the stack incl. cabling & supports. Max.length 20 m.

3.9 Drawing & manuals in English/French.

NOTES:

1) Electrical connection to be taken at stack bottom.
2) Any TÜV or similar institute test are not considered.
3) No cabling from the cabinet to the control room is considered.

Pos.	Quant.	Description per each FT8 TwinPac	Qty
Pos. 1	1	Gas sampling system	2
Pos. 2	1	Heated sample lines (15 meters)	2
Pos. 3	1	Analyzer modules MAIHAK S 710 in a outside cabinet for: (CO, CO2, NO, O2)	2
Pos. 3.2	1	Analyzer module UNOR for SO2	2
Pos. 4	1	Dust Monitoring system SICK OMD41	2
Pos. 5	1	Flow, temp. and abs. pressure	2
Pos. 6	1	Data acquisition system consisting in 2 PC with MODBUS standard connection (for both systems)	1
Pos. 7	1	Special span gases set for control of both systems	1
Pos. 8	1	Installation (for both systems)	1

Attachments

- Process Diagramm **(later)**
- Gas Analysis – S 700, Modular Gas Analyzer System **(later)**
- S 700, Modular Gas Analyzer System, Data Sheet **(later)**
- OMD 41 – Dust Concentration Monitor **(later)**
- FW 100 – Dust Concentration Measuring Device **(later)**
- RM 210 – Dust Concentration **(later)**

18. CO CATALYST

Attachments

- Description **(later)**
- Performance Data **(later)**

19. BLACK-START DIESEL GENERATOR UNIT

GENSET-PERFORMANCE	515 kVA / 412 kW Stand-by Power
Voltage:	460 / 240 V
Frequency:	60 Hz
Speed:	1.800 1/min
Cos. phi:	0,8

Details see attached. **(later)**

20. OPTIONS - OUTSIDE GT BASE SCOPE

20.1 HI-FOG System

Attachment

- HiFog Fire Fighting MAU, Drawing No. 10000175886 **(later)**
- HI-FOG water mist fire protection
  Protecting Machinery & Power Generation Equipment **(later)**

20.2 Closed Cooling System

Attachments

- Calculation **(later)**
- P&I Diagram **(later)**
- Drawing Cooling Plant / Units **(later)**

20.3 Air Cooled Solutions

Attachment

- DAC Generators **(later)**
- Oil/air heat exchangers for industrial use **(later)**
- Specification Air-Oil-Cooler **(later)**

20.4 Anti-Icing System with Exhaust and Sound Protection System

Attachment

- Drawing **(later)**

In the drawing is integrated the exhaust heating system for anti-icing with many references in all our compressor station installations in Germany for E.on Ruhrgas and WINGAS.

Also in this drawing is shown the modification of the exhaust stack according to lower sound restriction in connection with neighbours in an urban area.

In reference to the German TA Lärm the specification for this kind of area have different mdifications of the night level for this area and for the operation time per day.

20.5 Air Pressure Skid

Attachment

- Layout Air Pressure Skid **(later)**
- KAESER Compressor SK 19/26 **(later)**
- KAESER Air Receivers **(later)**

21. QUALITY ASSURANCE AND CONTROL

Attachments

- TG-QUALITY ASSURANCE **(later)**
- Certificates **(later)**
- Inspection and test plan **(later)**
- PWPS FT8-1 and FT8-3 Production Acceptance Test Overview **(later)**
- PWPS Factory Acceptance Tests **(later)**
- Field-Acceptance Test Procedure , Thermodynamic Performance Test of a FT8-30/36 TwinPac (Generator Drive) on Site **(later)**

22. TRAINING

Attachments

- Training at Customer site **(later)**
- Training at Contractor site **(later)**
- Time Schedule of Traing **(later)**
- Course description for Operator Team **(later)**
- Course description for Mechanical Team **(later)**
- Course description for Electrical Team **(later)**
- Course description for Control & Instrumentation Team **(later)**

23. INFORMATION ON GAS TURBINE SERVICE

Attachments

- FT8 General Service Concept **(later)**
- Budgetary Offer **(later)**
- Special Tools FT8 **(later)**
- GT Spare Parts Proposal **(later)**
- Audit Spare Parts Proposal **(later)**
- Generator Spare Parts (BEM) **(later)**

24. QUALIFICATION OF TENDERERS

(later)

25. ANNUAL REPORTS

MAN TURBO AG **(later)**

and

MAN AG **(later)**

Reference List
FT8 Industrial Gas Turbine
Status: 30. September 2007

Customer / site location	No. of units	Application	Commis-sioning	Running hours
Public Service Electric & Gas Co. Burlington, New Jersey, USA	4 (2 TP) 4 (2 TP)	Combined Cycle Combined Cycle	Mar 92 June 93 (Status: 31.12.04)	total 116.805
Futian Power Company Shenzhen, PR China	1 (PP)	Combined Cycle	Mar 92 (Status: 31.12.04)	54.641
Newfoundland and Labrador Hydro Happy Valley, Labrador, Canada	1 (PP)	Power Generation (Peaking plus Synchronous Condensing)	March 92 (Status: 31.12.04)	total 1.163 (64.372)
Ebara Corporation Sodegaura, Japan	1 (PP)	Power Generation (Peaking)	July 92 (Status: 31.12.04)	10.626
MAN TURBO AG Oberhausen, Germany	1 (MD)	Test Stand	July 92	500
United Technologie Corporation **P & W Manufacturing Division** East Hartford, Connecticut, USA	1 (PP)	Cogeneration	Jan. 93 (Status: 31.12.04)	71.776
Mitsubishi Heavy Industries Takasago, Hyogo Car & Passenger Ferry, Japan	2 GG8 f. MFT8 (MD)	Marine Propulsion	1994 (Status: 31.12.02)	total 13.000
Hainan Electric Power Company Sanya, Hainan Province, PR China	2 (TP) 2 (TP)	Power Generation (Base Load)	Apr. 94 June 95 (Status: 31.12.04)	total 203.171
Jamaica Public Service Company Montego Bay, Jamaica	2 (PP)	Power Generation (Base Load)	Dec. 94 (Status: 31.12.04)	total 24.476
Industriekraftwerk Baienfurt Baienfurt, Germany	1 (PP)	Combined Cycle	Feb. 95	97.084
Massachusetts Water Resources Authority (formerly Boston Edison Company) Deer Island, Boston, Massachusetts, USA	2 (PP)	Power Generation (Emergency)	June 95 (Status: 31.12.04)	total 3.609
Rhodia Energy Melle, France	1 (PP)	Cogeneration	Sep. 95	43.694
E.ON Ruhrgas Aktiengesellschaft Station Werne 7, Germany	1 (MD)	Pipeline	Oct. 95	37.905
Energieversorgung Oberhausen AG Oberhausen, Germany	1 (PP)	Cogeneration	Dec. 95	71.938
Wuxi Suyuan Gas Turbine Electric Company Wuxi County, PR China	2 (TP)	Combined Cycle	July 96 (Status: 31.12.04)	total 19.700
ESYS-MONTENAY Clermont-Ferrand, France	1 (PP)	Cogeneration	Oct. 96	38.952

PP = PowerPac, TP = TwinPac,
SP = SwiftPac, MP = MobilePac,
MD = Mechanical Drive

Reference List
FT8 Industrial Gas Turbine
Status: 30. September 2007

Customer / site location	No. of units	Application	Commis-sioning	Running hours
Chloralp	3 (PP)	Cogeneration	Sep. 96	50.045
Pont de Claix, France			Sep. 96	51.932
			Oct. 96	52.516
Cogeneration Management Steiermark	1 (PP)	Cogeneration-	Sep. 96	69.189
Graz, Austria				
Solvay Deutschland	2 (TP)	Cogeneration	Sep. 96	87.765
Rheinberg, Germany				86.437
TransCanada Pipelines				
Kapuskasing, Canada	1 (PP)	Combined Cycle	Dec. 96	59.072
North Bay, Canada	1 (PP)	Combined Cycle	Dec. 96	59.022
			(Status: 31.12.04)	
Asahi Chemical Industry Co. Ltd.	1 GG8 f.	Combined Cycle	Apr. 97	63.000
Kanagawa, Japan	MFT8		(Status: 31.12.04)	
	(PP)			
Chengdu AES-Kaihua	2 (TP)	Power Generation	June 97	total
Gas Turbine Power Co. Ltd.		(Base Load)	(Status: 31.12.04)	42.787
Chengdu, PR China				
I.C. Industrias, S.A.	2 (TP)	Power Generation	Sep. 97	total
La Dorada, Colombia		(Base Load)	(Status: 31.12.04)	19.407
Communauté Electrique du Benin				
Lorne, Togo	1 (PP)	Power Generation	June 98	15.841
Contonou, Benin	1 (PP)	(Base Load)	July 98	12.241
			(Status: 31.12.03)	
Endesa				
Charrua, Chile	2 (PP)	Power Generation	Feb. 99	total
		(Base Load)	(Status: 31.12.02)	7.053
Valdivia, Chile	2 (TP)	Power Generation	Mar 99	total
	2 (PP)	(Base Load)	(Status: 31.12.02)	8.132
BASF AG für WINGAS GmbH				
Rückersdorf Station, Germany	1 (MD)	Pipeline	June 99	19.632
Mallnow Station, Germany	2 (MD)	Pipeline	Oct. 99	34.804
			Nov. 99	33.076
Tomen Power Samukawa	2 (TP)	Combined Cycle	June 99	total
Samukawa, Kanagawa, Japan			(Status: 31.12.04)	32.423
Ebara Corporation	2 (TP)	Combined Cycle	June 99	total
Fujisawa, Kanagawa, Japan			(Status: 31.12.04)	32.715
E.ON Ruhrgas Aktiengesellschaft	1 (MD)	Pipeline	June 99	24.162
Station Werne 8, Germany				
Adisseo France S.A.S.	1 (PP)	Cogeneration	Sep. 99	30.109
Commentry, France				
CURCHAL	1 (PP)	Cogeneration	Dec. 99	26.408
Chalon s/Saône, France				
Tokyo Metropolitan Government	2 GG8 f.	Pump Drive	Jan. 00	total
Kanto Chisei, Japan	MFT8			278
	(MD)			

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Reference List
FT8 Industrial Gas Turbine
Status: 30. September 2007

Customer / site location	No. of units	Application	Commis-sioning	Running hours
Omaha Public Power District Omaha, Nebraska, USA	4 (2 TP)	Power Generation (Peaking)	May 00 (Status: 31.12.04)	total 10.994
Buckeye Power Greenville, Ohio, USA	8 (4 TP)	Power Generation (Peaking)	May 00 (Status: 31.12.04)	total 17.157
BASF AG für WINGAS GmbH				
Mallnow Station, Germany	1 (MD)	Pipeline	Jan. 01	36.760
Rückersdorf Station, Germany	1 (MD)	Pipeline	Apr. 01	24.998
Boremer San Martin de la Vega, Spain	1 (PP)	Cogeneration	May 01	51.130
Tokyo Metropolitan Government Higashi Kojiya Pumpstation, Tokio Japan	1 (PP)	Power Generation (Emergency)	Jan. 01 (Status: 31.12.04)	868
DPL Energy, Inc. Montpelier, Indiana, USA	8 (4 TP)	Power Generation (Peaking)	May 01 (Status: 31.12.04)	total 9.973
Tenaska Wolf Hills, Bristol, Virginia, USA	10 (5 TP)	Power Generation (Peaking)	July 01 (Status. 31.12.04)	total 6.533
Tenaska University Park, Chicago, Illinois, USA	12 (6 TP)	Power Generation (Peaking)	July 01 (Status: 31.12.04)	total 4.465
Constellation Power Handsome Lake, Rackland Township, Pennsylvania, USA	10 (5 TP)	Power Generation (Peaking)	July 01 (Status: 31.12.04)	total 6.224
Tenaska Big Sandy, Neal, West Virginia, USA	12 (6 TP)	Power Generation (Peaking)	July 01 (Status: 31.12.04)	total 5.023
Puget Sound Fredonia, Washington, USA	4 (2 TP)	Power Generation (Peaking)	July 01 (Status: 31.12.04)	total 8.725
Virgin Islands Water & Power Auth. St. Thomas, US Virgin Islands	1 (PP)	Power Generation (Base Load)	Sep. 01 (Status: 31.12.04)	5.220
CalPeak				
Escondido, California, USA	2 (TP)	Power Generation (Peaking)	Sep. 01 (Status: 31.12.04)	total 2.827
Border, California, USA	2 (TP)	Power Generation (Peaking)	Sep. 01 (Status: 31.12.04)	total 2.767
Panoche, California, USA	2 (TP)	Power Generation (Peaking)	Nov. 01 (Status: 31.12.04)	total 1.764
Benton PUD Benton Country, Washington, USA	1 (PP)	Power Generation (Peaking)	Oct. 01 (Status: 31.12.04)	1.025
Jamaica Public Service Company Montego Bay, Jamaica	1 (PP)	Power Generation (Peaking)	Jan. 02 (Status: 31.12.04)	6.599
City Utilities of Springfield Springfield, Missouri, USA	4 (2 TP)	Power Generation (Peaking)	Feb. 02 (Status: 31.12.02)	total 2.000
PacifiCorp Klamath Falls, Oregon, USA	4 (2 TP)	Power Generation (Peaking)	Apr. 02 (Status: 31.12.04)	total 1.725

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Reference List
FT8 Industrial Gas Turbine
Status: 30. September 2007

Customer / site location	No. of units	Application	Commis-sioning	Running hours
Ameren UE				
Peno Creek, Bowling Green, Missouri, USA	8 (4 TP)	Power Generation (Peaking)	Apr. 02 (Status: 31.12.03)	total 5.814
Venice, Meremac, Illinois, USA	2 (TP)	Power Generation (Peaking)	May 02 (Status: 31.12.03)	total 1.168
Rochester Public Utility Rochester, Minnesota, USA	2 (TP)	Power Generation (Peaking)	May 02 (Status: 31.12.04	total 1.564
CalPeak				
Vaca Dixon, California, USA	2 (TP)	Power Generation (Peaking)	June 02 (Status: 31.12.04)	total 1.379
El Cajon, California, USA	2 (TP)	Power Generation (Peaking)	June 02 (Status: 31.12.02)	total 2.636
Petrobras Termoceara Fortaleza, Brazil	8 (4 TP)	Power Generation (Peaking)	June 02 (Status: 31.12.02)	total 21.398
FPL Energy Bayswater, New York, USA	2 (TP)	Power Generation (Peaking)	June 02 (Status: 31.12.04)	total 8.491
Ebara Corporation Sodegaura, Japan	3 (PP)	Combined Cycle	Dec. 02 (Status: 31.12.04)	total 22.823
Michigan Public Power Kalkaska, Michigan, USA	2 (TP)	Power Generation (Peaking)	Dec. 02 (Status: 31.12.04)	total 993
Empire Electric Sarcoxie, Missouri, USA	4 (2 TP)	Power Generation (Peaking)	Feb. 03 (Status: 31.12.04)	total 4.624
Endesa Mahon, Menorca, Spain	2 (TP)	Power Generation (Peaking)	June 03 (Status: 31.12.04)	total 3.043
Endesa Arona, Tenerife, Spain	2 (PP)	Power Generation (Peaking)	June 03 (Status: 31.12.04)	total 10.367
FPL Energy Jamaica Bay, New York, USA	2 (SP50)	Power Generation (Peaking)	June 03 (Status: 31.12.04)	total 2.030
Global Commons Greenport LLC Greenport, New York, USA	2 (SP50)	Power Generation (Peaking)	July 03 (Status: 31.12.04)	total 3.182
Electricity Supply Board				
Asahi, County Mayo, Ireland	2 (SP50)	Power Generation (Peaking)	Dec. 03 (Status: 31.12.04)	total 630
Aghada, County Cork, Ireland	2 (SP50)	Power Generation (Peaking)	Dec. 03 (Status: 31.12.04)	total 561
Ministry of Oil Al-Bashrah, Iraq	2 (TP)	Power Generation (Base Load)	Mar 04	
Ministry of Electricity Al-Hilla, Iraq	1 (PP)	Power Generation (Base Load)	Mar 04	6.400
Contact Energy Whirinaki, New Zealand	6 (SP50)	Power Generation (Peaking)	Apr. 04 (Status: 31.12.04)	total 1.148
Wisconsin Public Power Kaukaua, Wisconsin, USA	2 (TP)	Power Generation (Peaking)	May 04 (Status: 31.12.04)	total 958

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Reference List
FT8 Industrial Gas Turbine
Status: 30. September 2007

Customer / site location	No. of units	Application	Commis-sioning	Running hours
Endesa Guio de Isora, Tenerife, Spain	2 (SP50)	Power Generation (Peaking)	Sep. 04 (Status: 31.12.04)	total 282
Electricity Supply Board Rhode, County Offaly, Ireland	4 (SP50)	Power Generation (Peaking)	Sep. 04 (Status: 31.12.04)	total 483
Endesa Las Palmas, Spain	1 (MP)	Power Generation (Peaking)	Nov. 04	
Tokyo Metropolitan Government Kanto Chisei, Japan	2 GG8 f. MFT8 (MD)	Pump Drive	Jan. 05 (Status: 31.12.04)	total 400
Kraftnät Åland AB Tingsbacka, Åland, Finland	1 (PP)	Power Generation (Emergency)	March 05	155
BASF AG für WINGAS GmbH Reckrod Station, Germany	1 (MD)	Pipeline	May 05	15.318
BASF AG für WINGAS GmbH				
Rückersdorf Station, Germany	1 (MD)	Pipeline	Feb. 06	6.791
Eischleben Station, Germany	1 (MD)	Pipeline	May 06	1.496
Bell Bay Power Tasmania, Australia	6 (3TP)	Power Generation (Peaking)	Mar 06	
JSC Energy Invest Gardabani Power Station Republic of Georgia	4 (SP50)	Power Generation (Intermediate)	Apr. 06	
Amber Investment Changxing County, Zhejiang, PR China	2 (SP50)	Combined Cycle	June 06	
Beijing Blue Sky Gas-fired Cogeneration Co. Beijing, PR China	4 (2 TP)	Cogeneration	June 06	
EADC/EAS Charrua, Chile	4 (SP50)	Power Generation (Base Load)	Nov. 06	
Seminole Electric Cooperative Central Florida, USA	10 (SP50)	Power Generation (Peaking)	Dec. 06	
RAO UES Moscow, Russia	10 (MP)	Power Generation (Peaking)	Jan. 07	
EDF #1 Various Islands	1 (MP)	Power Generation (Peaking)	Feb. 07	
Guongzhou University Guongzhou, PR China	4 (SP50)	Combined Cycle	June 07	
North Carolina Electric Memership Corp.				
Wake County, North Carolina	12 (SP50)	Power Generation	June 07	
Person County, North Carolina	10 (SP50)	(Peaking)	Dec. 07	
Fingrid Oyj Olkiluoto, Finland	4 (2 TP)	Power Generation (Emergency)	June 07	
EDF #2 Various Islands	1 (MP)	Power Generation (Peaking)	Oct. 07	

PP = PowerPac, TP = TwinPac,
SP = SwiftPac, MP = MobilePac,
MD = Mechanical Drive

Reference List
FT8 Industrial Gas Turbine
Status: 30. September 2007

Customer / site location	No. of units	Application	Commis-sioning	Running hours
ZAO UK "DKM-ENGINEERING" Moscow, Russia	2 (SP25)	Combined Cycle (Cogeneration)	Dec. 07	
Campanario Generacion II Charrua, Chile	2 (SP50)	Power Generation (Base Load)	Dec. 07	
STATTNETT SF Tjeldbergodden, Norway	7 (MP)	Power Generation (Emergency)	Dec. 07	
STATTNETT SF Nyhamna, Norway	6 (SP50)	Power Generation (Intermediate)	Dec. 07	
Nevada Power Company Las Vegas, Nevada, USA	24 (SP50)	Power Generation (Peaking)	Apr. 08	
Endesa				
Ibiza, Spain	1 (PP)	Power Generation (Peaking)	May 08	
Ibiza, Spain	1 (SP25)	Power Generation (Peaking)	Dec. 08	
Endesa Mahón, Menorca, Spain	2 (SP50)	Power Generation (Peaking)	June 08	
Puerto Rico Electric Power Authority Mayaguez, Puerto Rico	8 (SP50)	Power Generation (Intermediate)	June 08	
Generacion Mediterranea S.A. Central Modesto Maranzana Rio Cuarto, Argentina	4 (SP50)	Power Generation (Base Load)	July 08	
MEGAL Waidhaus, Germany	1 (MD)	Pipeline	Nov. 08	
Endesa Mahón, Menorca, Spain	2 (SP50)	Power Generation (Peaking)	Dec. 08	
Tokyo Metropolitan Government Higashi Kojiya Pump Station Unit 2 Tokyo, Japan	1 (PP)	Power Generation (Emergency)	Dec. 09	
Total no. of engines in operation and running hours	**232**			
Total no. of engines sold	**356**			**2.057.997**

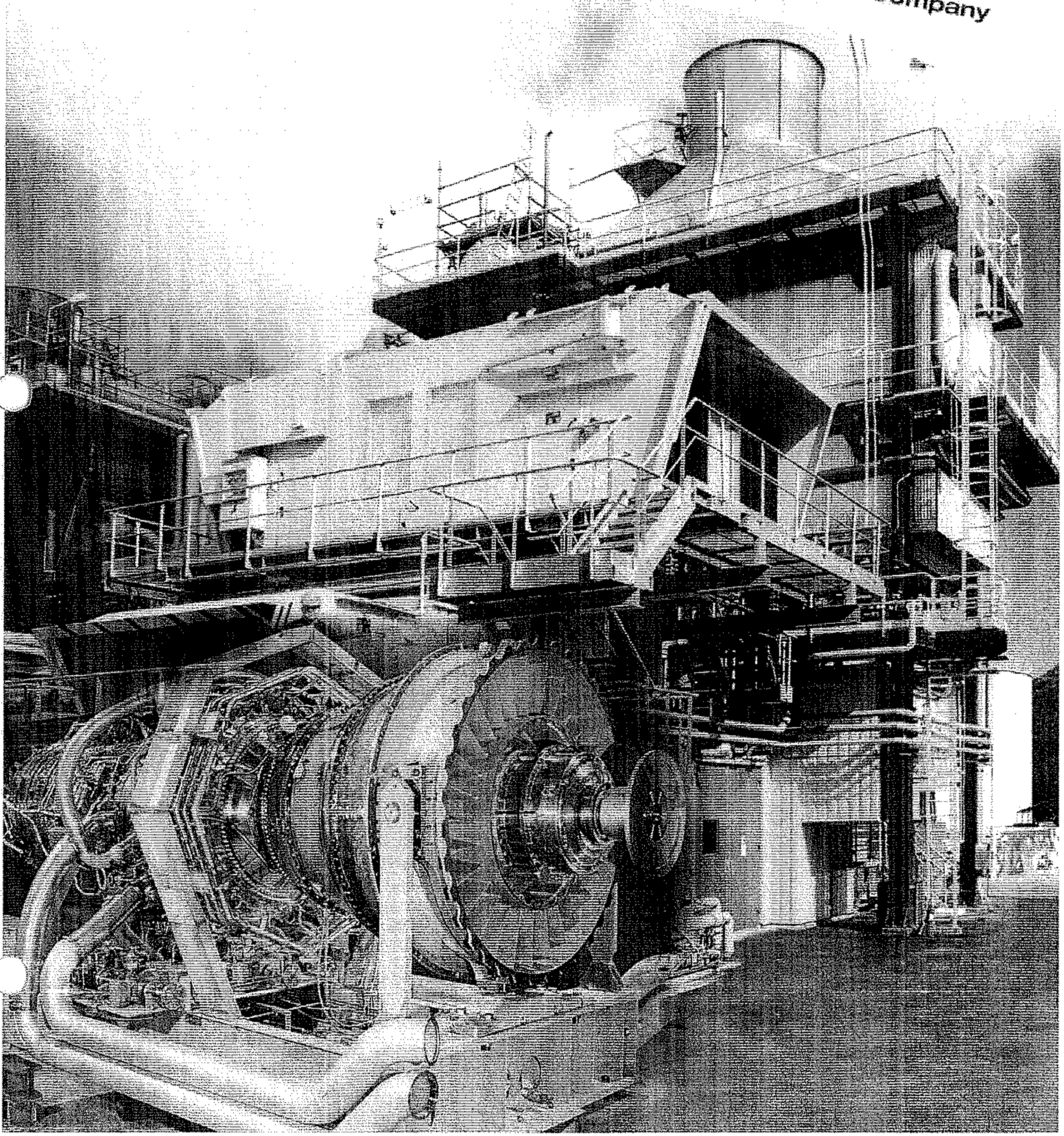
PP = PowerPac, TP = TwinPac,
SP = SwiftPac, MP = MobilePac,
MD = Mechanical Drive

GHH BORSIG

FT8 Power Key to Plant Upgrade

MAN TURBO

Welcome to the new Company



FT8 Power Key to Plant Upgrade

Revamping one of the first cogeneration plants in Europe

by Roberto Chellini, Diesel & Gas Turbine Worldwide
January/February 1999

The chemical works of the French company Rhodia (formerly Rhône-Poulenc Chemie) in Pont-de-Claix, is one of the largest industrial plants of the Grenoble region in southern France. With the acquisition of a capital share from LaRoche Industries Inc., all of Rhône-Poulenc Chimie's activities related to chlorine production were transferred to a joint venture (50 % LaRoche, 50 % Rhodia) named Chloralp.

Back in 1969, a large size cogeneration system was started at Pont-de-Claix to generate on-site electric power and process steam. The plant was originally based on eight Frame 5LA gas turbines rated 15 MW each, of which the first two units were delivered by Nuovo Pignone and the remaining by Alstom. In 1972 two similar units type Frame 5N rated 25 MW from Alstom were added. All 10 units are fitted with double pressure heat recovery steam generators from Babcock Atlantique. The HRSGs are placed directly on the turbine exhaust duct to produce superheated process steam at 30 bar and 270 °C, and a small amount of steam at 8 bar and 190 °C was also made available for flashing purposes.

Despite the relatively low efficiency of the industrial gas turbines available in the 1960s (22-24 %), the total fuel utilization rate of the cogeneration plant was quite high at approximately 70 %. The turbines were originally operated on liquid fuel and then shifted to natural gas after connection of the site to a main pipeline, leaving the liquid fuel as a backup in case of interruption of the gas supply. Furthermore, steam injection boosted the power of the first generation Frame 5s to 19 MW.

Normally the gas supply pressure to the plant is higher than required by the turbine fuel systems. However, should the pipeline pressure drop below the pressure needed by the gas turbines, single-stage Ariel compressors will take care of the necessary recompression.

In June 1996, three of the first heavy-duty industrial gas turbines were replaced by aeroderivative FT8 gas turbines ordered one year earlier from GHH BORSIG. The selection was made after an investigation of several parameters, two of which were of fundamental importance. The key element is the fact that the FT8 has a very similar mass flow compared to the Frame 5LA, so that the existing boilers could be used again after refurbishing and, secondly, the old foundation block could easily host the FT8 without major modifications.

After completion of the revamping program, operated by a 60 % ChlorAlp and 40 % Rhône-Poulenc joint company named CEVCO, the cogeneration plant has a capacity of 205 MW electric power and 700 t/h of process steam production.

Today, the whole cogeneration system is managed in the following mode:

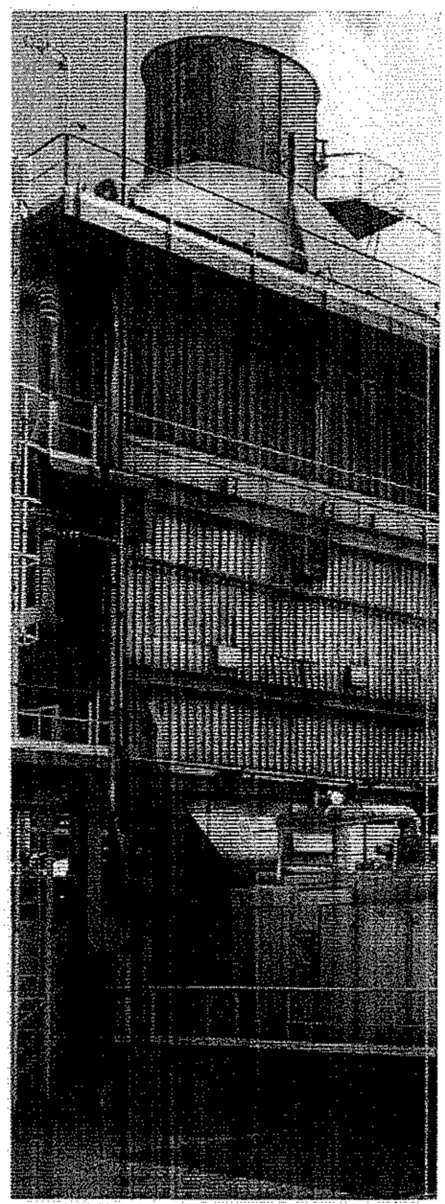
• The three FT8 units run at baseload; all electricity is sold to EDF (Électricité de France) according to the new DIGEC tariff commitment agreed with EDF and the steam is fed into the plant steam grid.

• The additional steam demand of the site is covered by starting up one or more Frame 5 units on request. The electricity generated in this way is absorbed at the chemical site. In case of further demand in electricity, this is bought from the EDF grid.

CEVCO has concluded a 12-year agreement with EDF to sell all the electric power produced by the FT8 gas turbines to the French utility in order to take advantage of the government incentives for new high-efficiency cogeneration plants. In France, these incentives are granted for plants with a total fuel utilization rate over 65 %, and the new section of the CEVCO plant is in the range of 88 %.

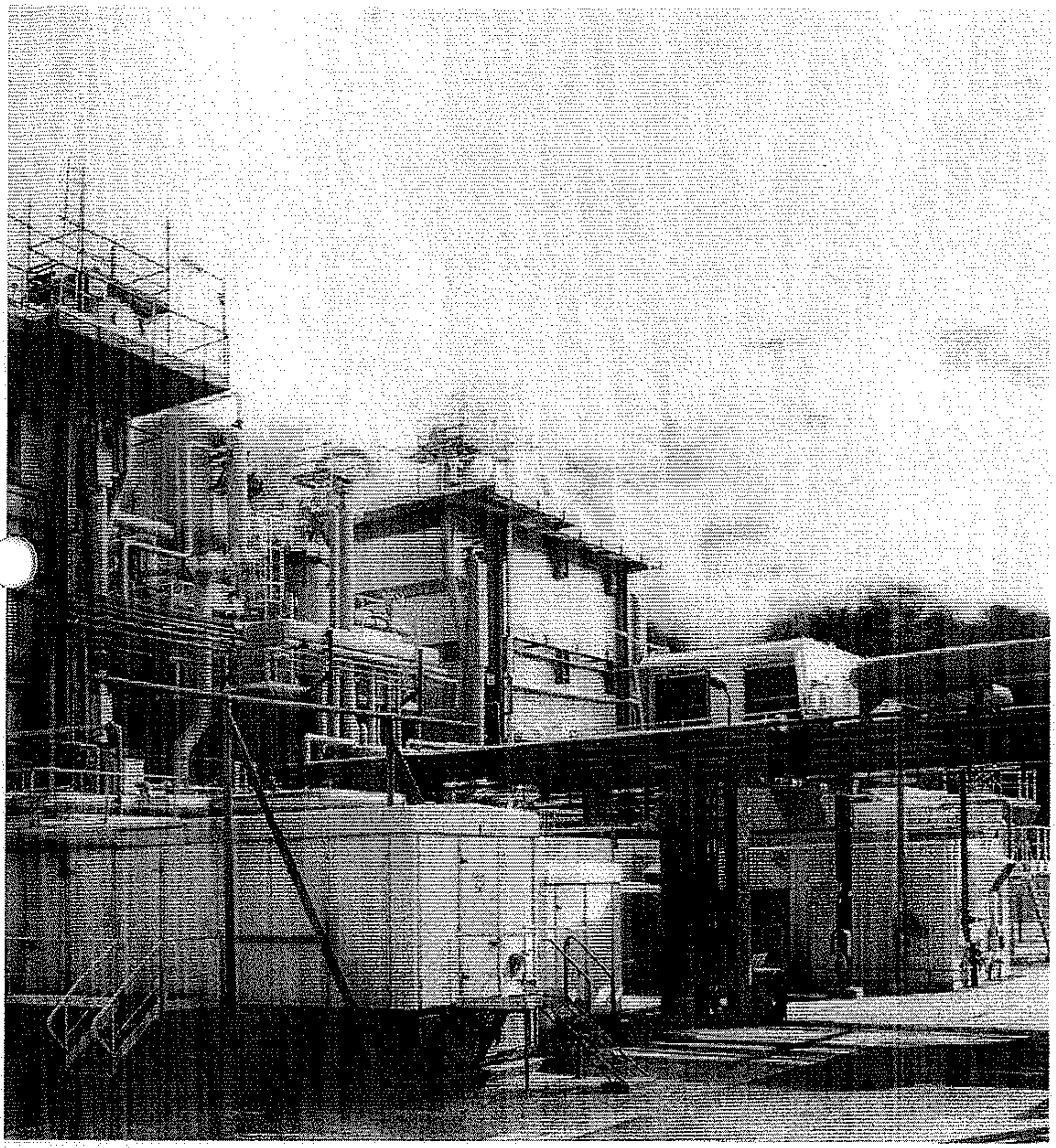
The whole cogeneration site is managed from the central control room where new monitors of Foxboro DCS have replaced the old synoptic panels of the scrapped machines. The new units are controlled via local control panels, which consist of a Woodward NetCon 5000 engine controller, a Siemens S5-115U PLC system with COROS visualization software. The COROS screens are remodeled on the CRT of the main control room so that the operator can run the machines from either position. Each gas turbine can be operated independently. The only common auxiliary for each group of two units is the water demineralization plant serving two boilers, while all the rest is separated.

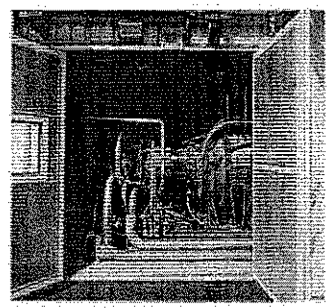
GHH BORSIG has installed the FT8 gas turbines on the existing foundations, with all equipment covered by waterproof and sound-attenuating enclosures that have been provided with a CO_2 fire protection system, as well as a forced ventilation system to take the heat radiation from the turbine outer casing. The turbine intake air system with filters and anti-icing device was delivered by Delbag and is installed upstream of the gas generator compartment. The



The cogeneration plant at Pont-de-Claix, with a view of an existing Frame 5 gas turbine in the foreground and the new FT8 installation in the background.

A closer view of the complete FT8 gas turbine generator package and the refurbished HRSG.





The FT8 gas generator, with a 25 MW output.

HRSG was left in its vertical position above the turbine exhaust. The natural circulation type HRSGs operate without bypass so that the turbines always have to be operated in the cogeneration mode.

New water-cooled 11 kV, 50 Hz, 35 MVA generators from Alstom complete with lube oil and cooling systems replaced the previous generators at the drive end of the gas turbine.

Next to one side of the turbine enclosure a separate container houses the auxiliaries like the synthetic lube oil system and the electric motor for driving the hydraulic pump that actuates the gas turbine starter. Also housed there is a supplementary demineralization system that further purifies the water treated by the boiler feed system before it is injected in the turbine combustor for lowering NO_x emissions and increasing the power output.

CEVCO has the interest of selling as much power as available to EDF, so the FT8 turbines run constantly at full load. The three FT8 units were put into operation in November 1996. After a transition period during which the old EDF tariff contract was in force, the three FT8 cogeneration units have operated continuously since November 1997 according to the new DIGEC tariff. This is the first plant in France where FT8 turbines are kept at full load the year around.

In order to achieve the highest possible figures in terms of reliability and availability, CEVCO has awarded GHH BORSIG a full service maintenance contract which also implements the use of a floating gas generator or power turbine. In case of maintenance work required, GHH BORSIG's field personnel can replace a gas generator within 72 hours and a power turbine within 96 hours (intervention on the power turbine calls for realignment of the gas generator).

GHH BORSIG's After Sales division relies on native French or French-speaking field engineers to care for and support the five units now in operation in France, including three at Pont-de-Claix, one at Melle and one at Clermont-Ferrand.

Recently Rhône-Poulenc Animal Nutrition has ordered one more FT8 Power Pac, which adds up to a fleet of six FT8s in France so far.

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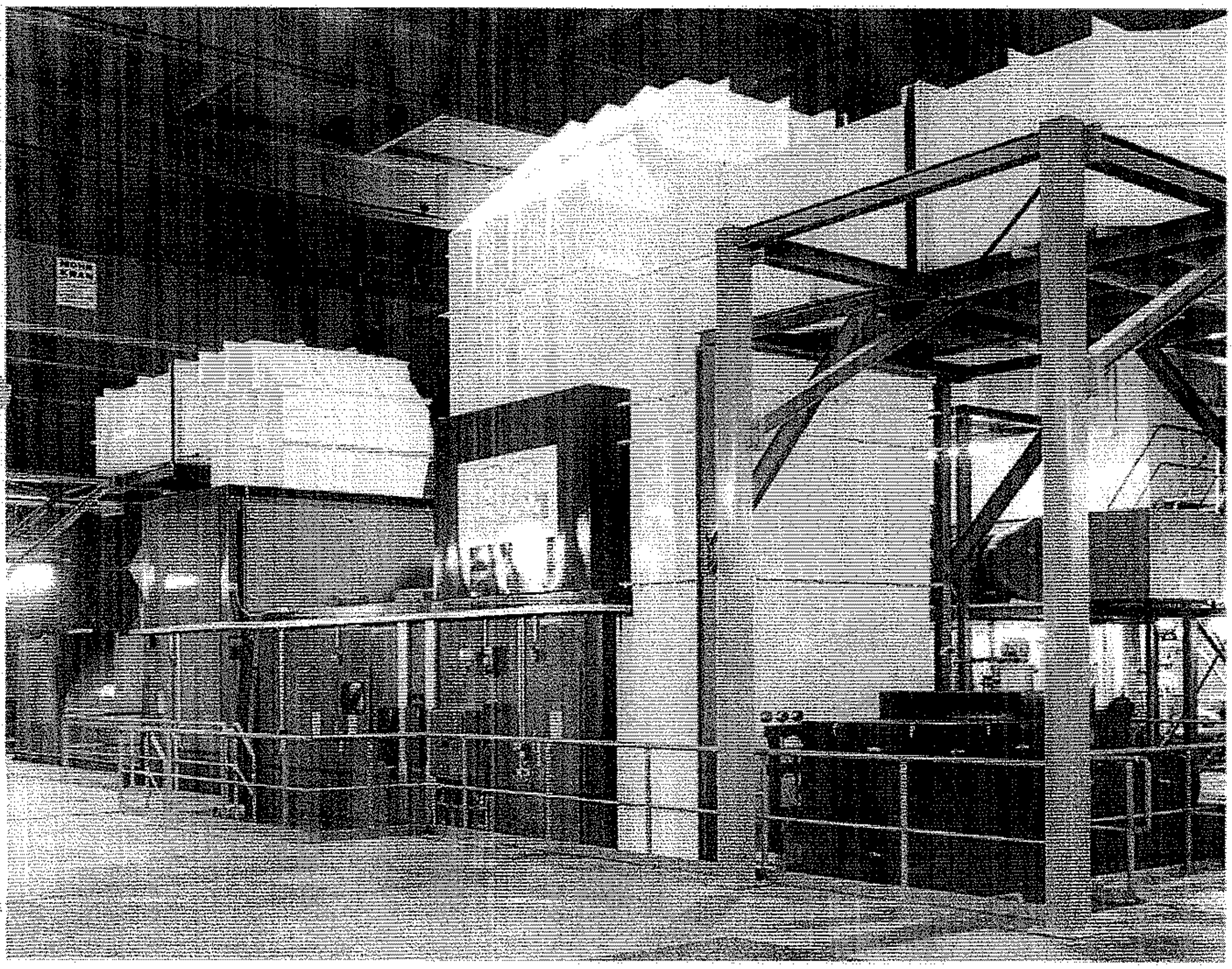
Integration of 25 MW gas turbine into existing power station

GHH BORSIG

MAN TURBO

Welcome to the new Company



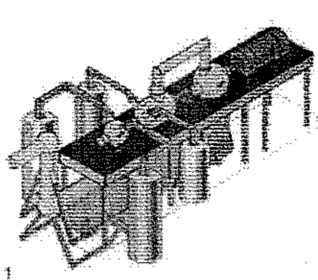
The combined heat and power station (CHP) supplied to the Oberhausen Public Utilities (EVO) by GHH BORSIG (formerly: MAN GHH) in 1974 has been revamped to produce an ultra-modern, fully automated gas turbine power station producing 25 MW of electric power. This was achieved by replacing the existing 50 MW helium turbine with a 25 MW gas turbine of type FT8. The old helium turbine had been developed and built by GHH in the course of development of the Federal Republic of Germany's fourth atomic programme. Components from the old installation have been largely integrated into the new plant design.

Basic concept

The Oberhausen Public Utilities (EVO) power station has been modified from a 50 MW helium gas turbine installation to provide an ultra-modern, automated gas turbine power station, which supplies the town of Oberhausen with heat as well as power.

The order to supply the 25 MW gas turbine unit including waste heat recovery facility was awarded in January 1995 to a consortium made up of Deutsche Babcock Anlagen GmbH and GHH BORSIG Turbomaschinen GmbH (then MAN GHH). The order comprised the complete delivery of plant components, including revamping of existing components and building structures.

The plant is situated at the heart of Oberhausen-Sterkrade and must therefore satisfy stringent environmental conditions in respect of exhaust gas and acoustic emissions. To achieve maximum cost efficiency, it was planned to incorporate old installation components as far as possible into the new



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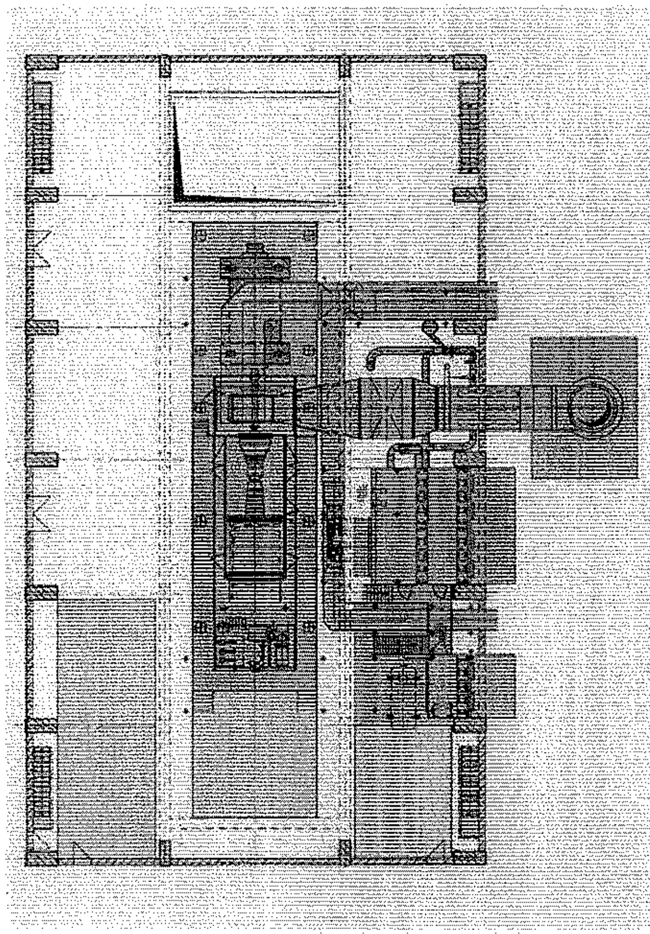
design. The basic concept provided for dismantling of the old helium turbine (Fig. 1) comprising a low-pressure compressor, high-pressure compressor, LP and HP turbines, and its replacement by a type FT8 industrial gas turbine.

This new total concept consists in essence of the existing power house with a waste heat recovery boiler, and the existing heat and power station with its systems and buildings. Virtually all parts of the buildings were re-used in the concept, including the crane installation in the power house (Fig. 2). For the new turbogroup a Siemens KWU electricity generator, which is over 20 years old, was partly overhauled, revamped and re-used. The consortium was responsible for the mechanical aspects of connecting it to the new machine train, and for the aspects of stability and vibration. The foundation underneath the electricity generator was also included in this total concept. The generator remained in its original position



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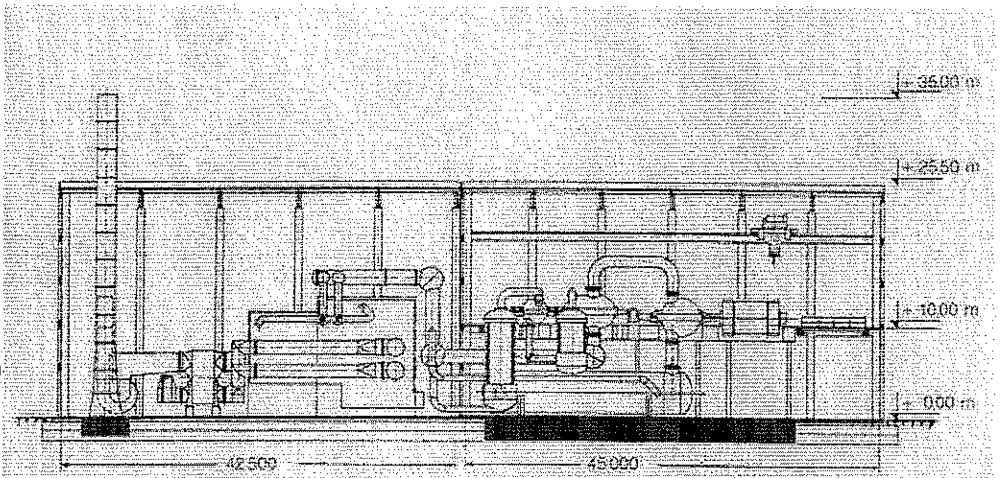
throughout the construction phase, with only the rotor requiring an overhaul and subsequent refitting. The new waste heat recovery boiler together with the air intake filters and exhaust silencer for the gas turbine were erected on the existing 10 m platform.

Fig. 3 shows a longitudinal section through the old turbogroup. Seen to the far right of the power house is the electricity generator, which is directly connected to the LP turbine. The gear train is followed by the HP group, comprising the HP turbine together with the high- and low-pressure compressors.

Lying beneath the turbine is the heat exchanger, preceded by a precooler and intercooler.

The power house was re-used in its entirety for the new gas turbine unit. In principle all the old turbine casings and heat exchangers in this area of the installation were completely removed, leaving the generator plus foundation and oil supply unit. This concept has permitted the generator main leads to be re-used without modification.

Parts of the old pipework system were also incorporated where possible into the new installation.



Longitudinal section through the power house of the 50 MW [illegible] gas turbine unit

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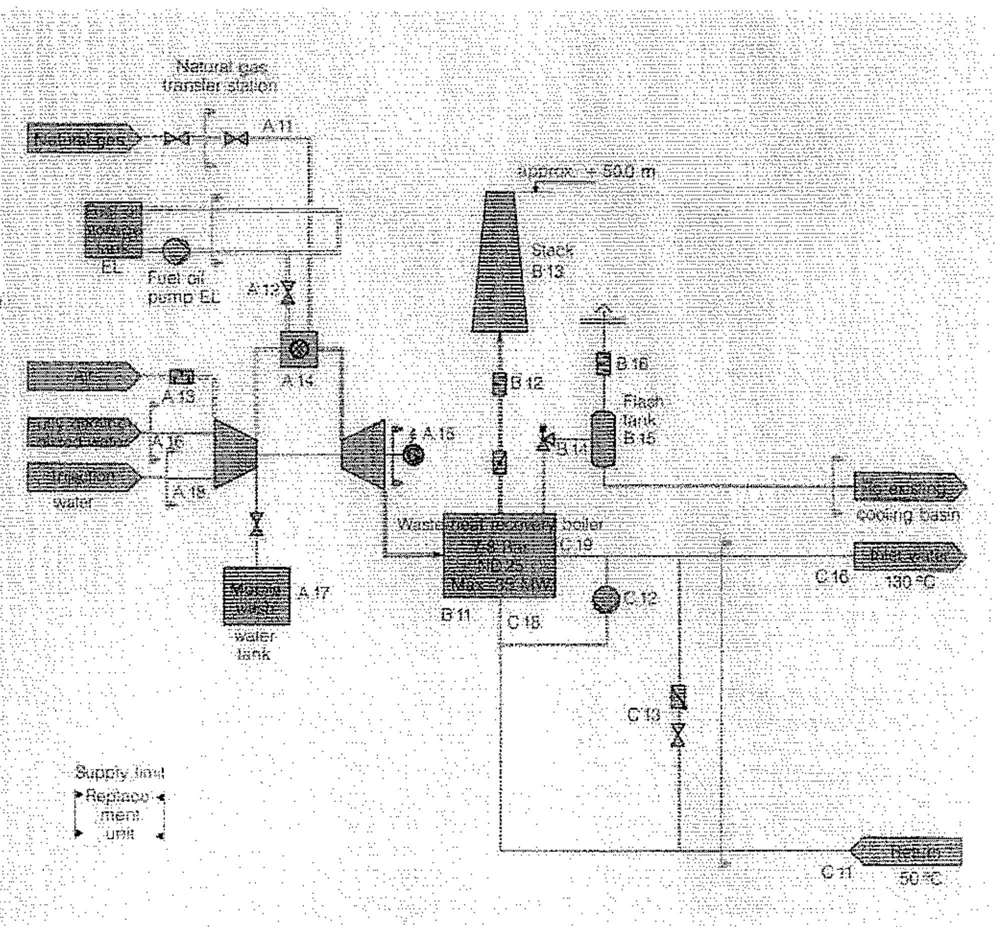

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The exhaust gas generated by the gas turbine at a temperature of approximately 465 °C is routed to a waste heat recovery boiler linked to the Oberhausen district heating supply system.

Fig. 4 shows the connection diagram. The gas turbine unit is rated for an air intake temperature of – 15 to + 30 °C at a relative air humidity of 60% and an erection height of 37 m.

The existing fuel oil tank and pumping station were used for oil operation, while a new natural gas supply system was installed to supply gas at a pressure of 42 bar.

Thanks to the modern technology embodied in the Dry Low NOx (DLN) combustor, exhaust gas values fall far below those stipulated in the "TA-Luft" technical directives on clean air for natural gas operation, while emissions during fuel oil operation are kept within limits by the injection of water. The exhaust gases from the combustor to drive the power turbine generate 24.4 MW of electricity under the existing boundary conditions. The intake and outlet pressure loss was guaranteed at 7.5 mbar and 18 mbar, respectively.

The flue gases of the gas turbine enter the waste heat recovery boiler at a temperature of 440–465 °C with a mass flow rate of 285,000–295,000 kg/h.

The unit can reach synchronous speed in 150 seconds and its rated output on rapid loading in a further 160 seconds, with a guaranteed availability of 96%.

Gas turbine

To drive the old generator, GHH BORSIG supplied a type FT8 gas turbine, which offers the ideal driving unit owing to its compact dimensions and extremely low heat rate. The FT8 is a gas turbine developed from the Pratt & Whitney type JT8D aircraft engine. More than 14,000 of these engines have been sold, making it one of the world's most widely used aero engines. This relatively new gas turbine has also benefited from the experience gained with the Pratt & Whitney PW 4000 and PW 2000 engines and the technical advances achieved on these; at this stage, more than 63 units have already been sold for industrial operation.

Like its FT4 predecessor, the FT8 is of modular construction, and is easily installed and dismantled thanks to the consistent use of the Packaging System. The combustor system used allows it to operate on liquid and gas fuels. Since the power turbine of the FT8 can be supplied to operate at 3000 rpm or 3600 rpm and also as a left- or right-handed turbine, it is eminently suitable as a prime mover for existing installations. The gas turbine is pre-erected in a compact form ready for operation on a base and comes completely fitted out for the plant, while the design of the ancillary units on so-called skids offers optimum flexibility for erection on site.

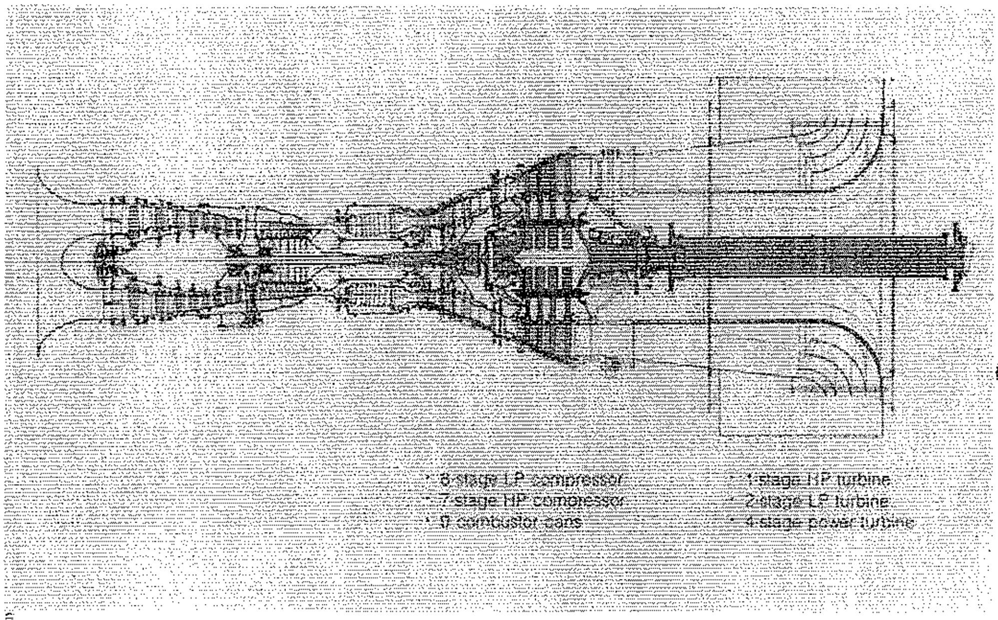

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Fig. 5 shows a section through the FT8 gas turbine with its low- and high-pressure compressors and related drive turbines. One feature worthy of special note is the power turbine, which is constructed in four stages. Following the power turbine is the standardized diaphragm coupling, which is connected directly to the old electricity generator. Looking at the weight data of the coupling, the technological approach derived from aircraft engine construction is naturally of interest compared with conventional power station applications. The modular structure of the FT8 facilitates swift assembly and disassembly of the components for maintenance purposes, making it possible to exchange its gas generator in just eight hours, for example. In the event of damage this modular system offers the operator an essential safeguard with regard to plant availability.

Boiler

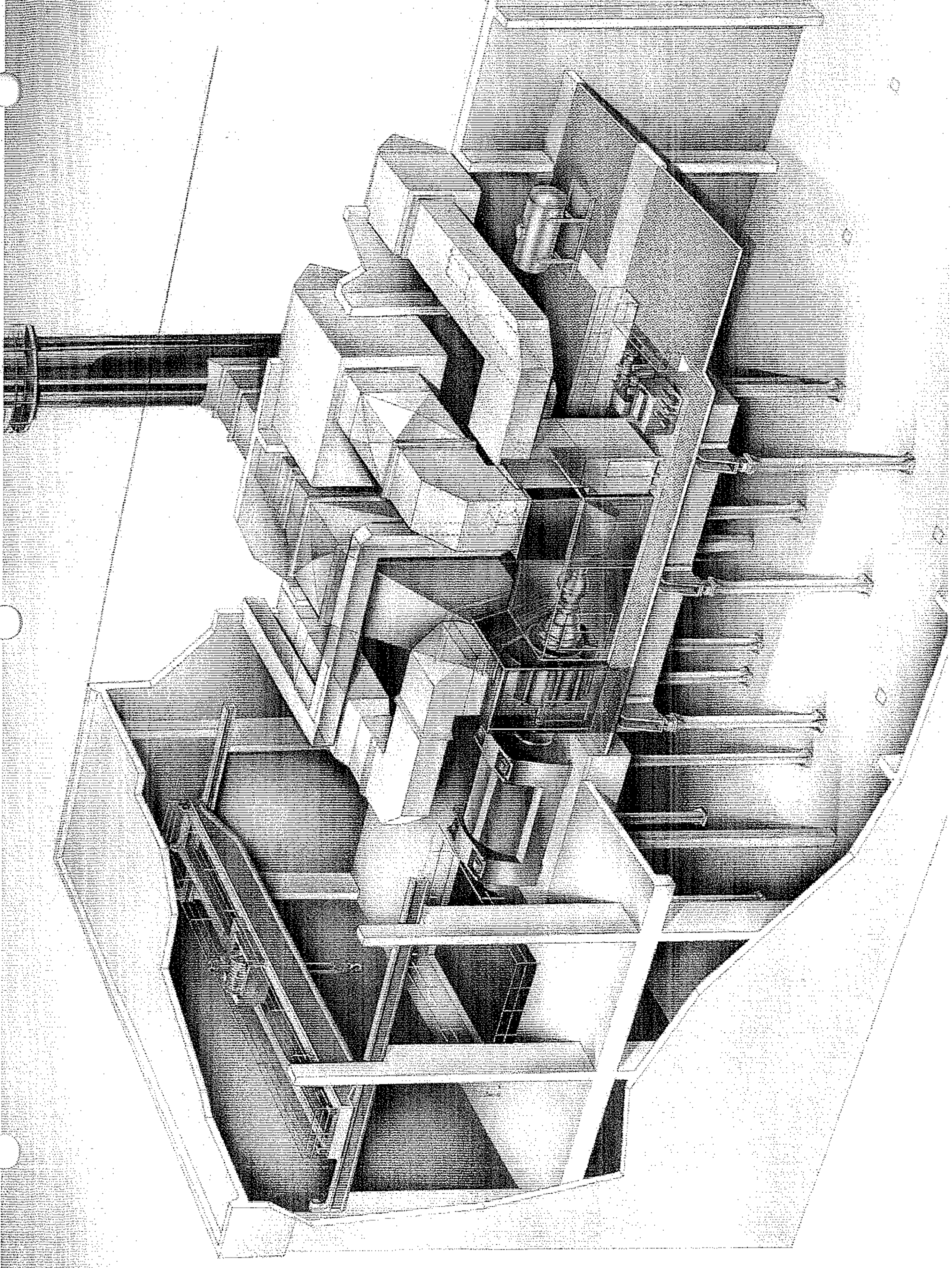
To increase the overall efficiency of the installation to 86% when firing it using natural gas and to 78% during oil operation, Deutsche Babcock Anlagen GmbH and Deutsche Babcock Omnical Industriekessel GmbH supplied the waste heat recovery facility (Fig. 6).

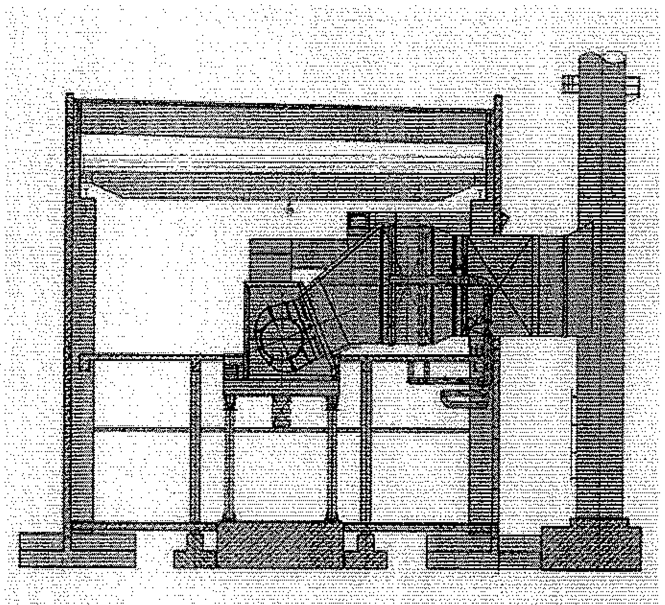
With a return temperature of 50 °C and a variable inlet temperature of 80–130 °C, this provides for 35 MW of thermal power to be tapped and fed into the Oberhausen district heating grid.

The gas turbine exhaust gases are routed to the heat exchanger through a collector box. Integral baffle plates ensure that the gases act evenly on the heating surface.

The heat exchanger is designed as a self-supporting vertical structure consisting of two modules. The finned-tube heating surface is suspended between the inlet and return headers, making it possible to dispense with both perforated plates, which ensure that the tubes are correctly spaced in relation to one another, and antinoise plates in the tube lanes to suppress vibrations. The waste heat recovery boiler is connected in a countercurrent arrangement.

To protect the heating surfaces, the return temperature was raised to 65 °C in natural gas operation by the addition of inlet water, a recirculation pump being installed for this purpose. When operating the gas turbine using oil as the fuel, the water injection temperature for the boiler has to be increased to 90 °C using the hot water recirculation pump. The boiler outlet temperature is a constant 130 °C, while the temperature of the flue gas after leaving the boiler lies between 107 and 119 °C.





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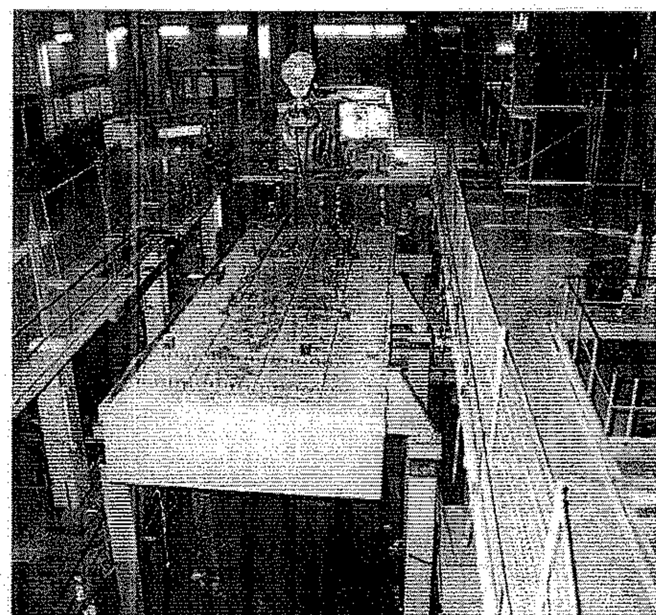

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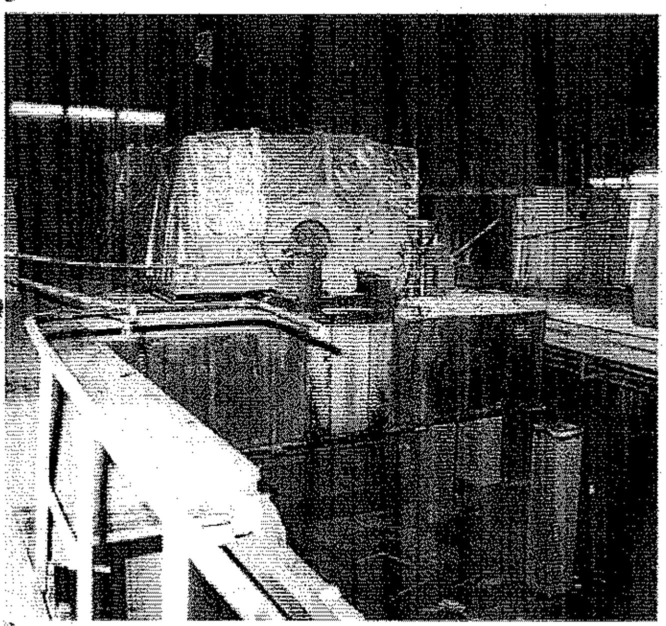

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In order to guarantee rapid start times of five minutes at peak loads, the boiler is kept warm during periods when the overall installation is shut down, the flue gas path being closed by means of a sealing damper behind the heating surface.

This is followed by the silencer on the flue gas side, which is rated for an immission pressure level of 35 dB(A) at a distance of 50 m from the base of the stack. The installation is provided with combined heat and sound insulation extending halfway up the silencer casing. The flue gases enter the double-shell stack via a flue gas duct.

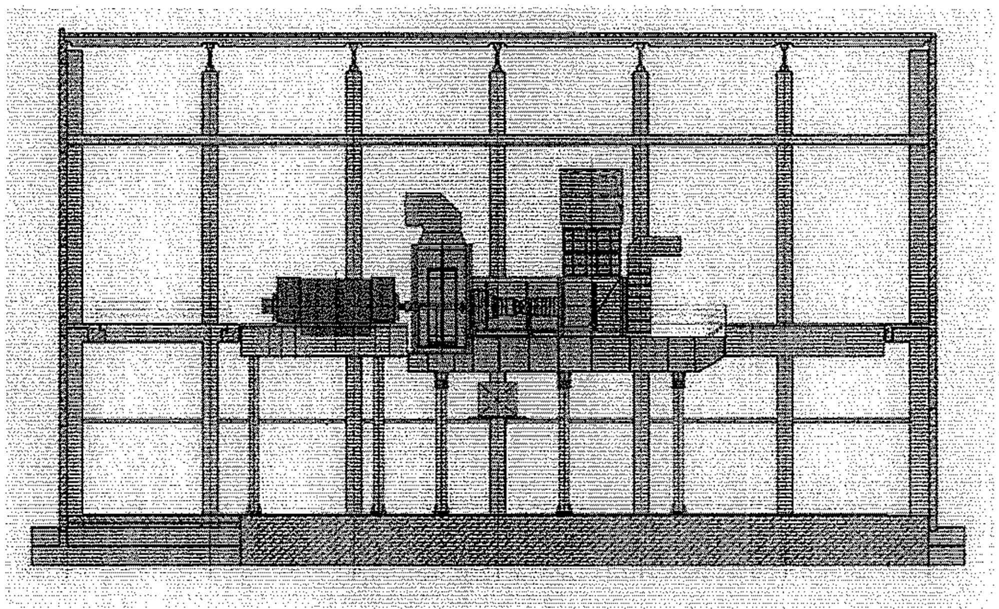
Layout to include the old components

A general problem which arises when revamping old units is of course the difficulty of obtaining drawings which are more than 20 years old. EVO was able to supply extraordinarily good engineering data, which was advantageous with regard to the very tight overall schedule. As already mentioned, the total concept allows for the incorporation of as many parts as possible of the old machine foundations and sole plates into the new foundation design. The original foundation for the helium gas turbine could not be re-utilized; although the shaft centreline of the FT8 package is at an extremely favourable height for cases such as this, a new foundation had to be constructed at greater depth for the gas turbine.

Fig. 7 shows the power house during the demolition work. The unaltered section of the electricity generator foundation can be seen clearly here after the front parts of the foundation had been cut away, as can the foundation columns, which were all re-used following minor modifications to accommodate the new column heads.

Fig. 8 shows the new gas turbine foundation being positioned on the column heads. This photograph also depicts the waste heat recovery boiler, which was erected in advance. The extremely high load-bearing capacity of the power house naturally offered considerable advantages here.

Fig. 9 is a section through the new installation with the old electricity generator and new gas turbine set. The generator was left unchanged on its foundation throughout the construction period, only the generator rotor being removed and overhauled. As the top view (Fig. 2) shows, it was possible to take over the whole of the old power house virtually without modification. The existing power house also proved highly satisfactory for the installation of the air filter systems for the gas turbine and for enclosure ventilation. To do this it was only necessary to break through the wall and add an extra steel construction in the existing power house wall (Fig. 10). Since the new gas turbine unit takes up considerably less space than the old unit, large areas around the 10 m platform had to be covered.



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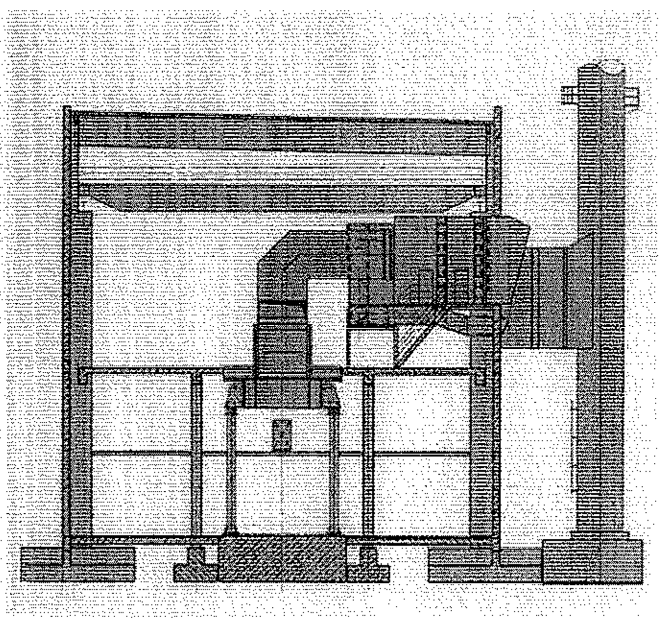

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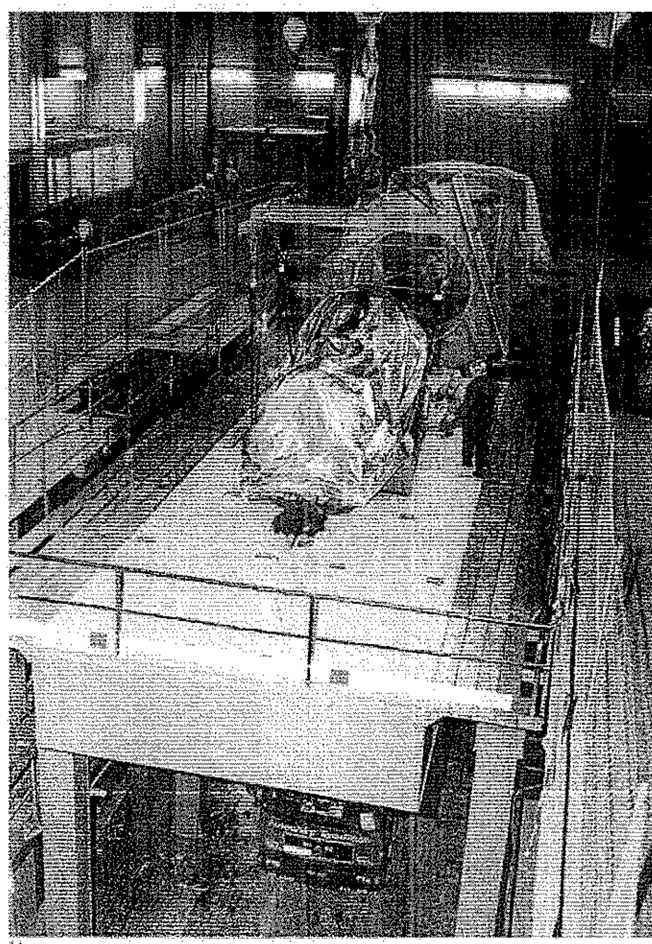

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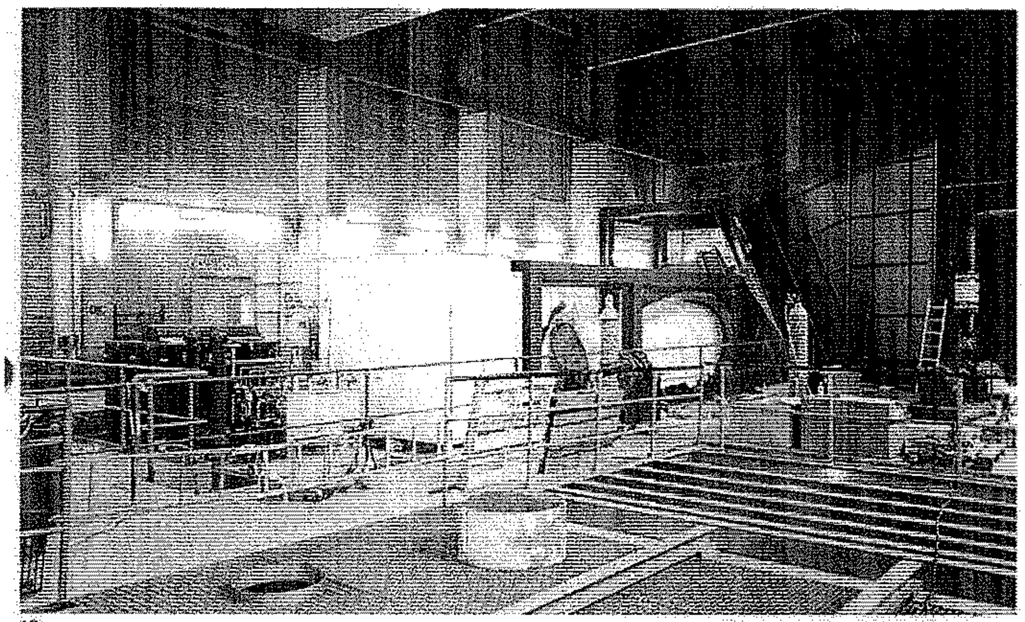
As can be seen from the sectional view, the generous height of the old power house crane pro-



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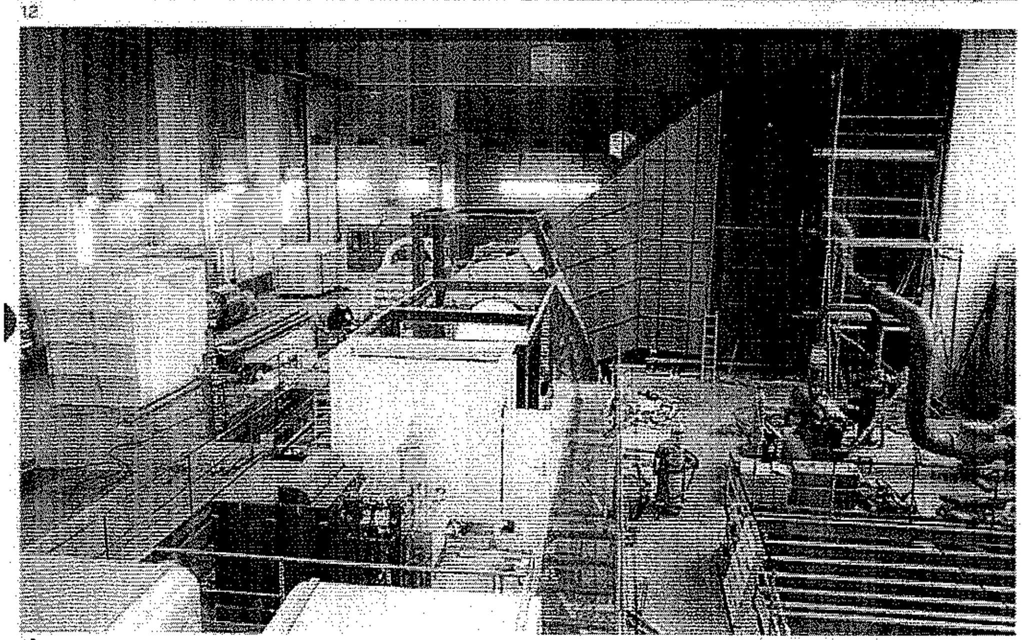

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vided the optimum conditions for erecting both the boiler and the ancillary units, thereby guaranteeing accessibility for maintenance and overhaul purposes.

Acoustic emissions

The inner-city location of the power station means that stringent, contractually safeguarded conditions were imposed with regard to sound. The sound projection outwards may not exceed 35 dB(A) at a distance of 50 m from the power house wall, while regulations permit an acoustic value of 80 dB(A) inside the power house.

Process control system

In the light of the demands made today on such facilities, the total complement of process control equipment accounts for a sizeable share of an installation of this kind. The process control concept enables the new gas turbine unit to be operated unsupervised from a central control station in Oberhausen. EVO placed a separate order with Siemens for the integration of this concept into the existing overall system.

Electricity generator

Re-utilization of the 50 MW electricity generator was an essential factor in this total concept. The generator has only 25,000 operating hours behind it and is in excellent condition. The generator rotor was overhauled, and the generator bearings on the drive side were fitted with an axial auxiliary bearing.

Figs. 11 to 13 show the gas turbine unit during the erection phase from 15 October to 01 December 1995. The installation was commissioned on schedule on 15 December 1995.

A large proportion of the gas turbine units now in use consist of old facilities which have been revamped or modified. Revamping old units to provide ultramodern, efficient gas turbine systems constitutes an extremely cost-effective concept for operators.

APPENDIX 8
BRUSH NEW GENERATOR PROPOSAL

Hearn, Bill G.

Subject: FW: Newfoundland & Labrador Hydro - Brush Generators

Attachments: PWPS_STD_13_8KV Set.pdf; ET2049.pdf; ET2541 Trans Pac.pdf; ET1147A.jpg; Industrial Power SM0000242E.pdf

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From: Derek King [mailto:Derek.King@houston.rm.fki-et.com]
Sent: Friday, November 16, 2007 2:38 PM
To: King, Brian; pierre.bovon@ca.manturbo.com
Cc: Mike.Watkins
Subject: Newfoundland & Labrador Hydro - Brush Generators

Brian/Pierre - I have been copied a recent email string on your project needs.

The enquiry was interpreted as a requirement for on site plant rebuild and no process to offer a new machine was initiated.

Brush currently manufactures a series of double ended generators for the Pratt & Whitney Twin Pac FT8-3 program and has delivered more than 80 units. P&W put the generator into their enclosure which includes the filters, but Brush could engineer an enclosure with top filter house similar to your existing machine. There would need to be careful consideration of the major interfaces to make the current machine fit, but thinking engineers could achieve that objective. Clients A/E would need to lead those integration efforts. Brush can assist with ideas, and where we would incorporate practical generator configuration changes (from present day standard) to best fit the project.

A set of standard 13.8Kv 60Hz data is attached here for your review - if your project needs special reactance's then let us know the target parameters. Delivery time would be ~ 12/14 months from completion of the drawing approval process.

Rough ball park costs for the new generator are:

a) BDAX7-290 ER with loose AVR. Base double ended generator open ventilated. US $ 2.5M
b) Top mounted TEWAC cooler assembly. US $250K
c) Option for alternate top mounted - replaceable pad type standard filter house US $300K
d) Acoustic and weather protecting canopy to enclose either TEWAC generator - or direct air cooled machine.
(Filter house in this case would then be roof mounted) - US $ 250K

Typical layout drawings for these generators are attached here. Note that ET1147 shows a CANOPY outline on a smaller TEWAC machine which would be of a length to enclose the new generator coupling face to face.

These budget numbers are strictly for guidance and do not cover special features that may be required for the project. They do not include Line or Neutral cubicles or off generator support systems - external radiators, water system, oil services, clutches etc, but Brush can offer or work with vendors for those if needed.

I hope this information is of help to your considerations - please let us know if we need to start a firm enquiry, and focus on your particular requirements.

Regards Derek
This message from Derek King

BRUSH Turbogenerators Inc. Houston
Tel: +1 281 580 1314 X208
Fax: +1 281 580 5801

Mobile: +1 281 923 1314
Email: derek.king@houston.rm.fki-et.com
Website: www.brush.eu

BRUSH Turbogenerators Inc. 15110 Northwest Freeway, Suite 150, Houston, Texas .77040 USA.

BRUSH ELECTRICAL MACHINES LTD

BRUSH ELECTRICAL MACHINES LTD

ELECTRICAL DATA SHEET

P O Box 18, Falcon Works, Loughborough, Leics. LE11 1HJ, England
Telephone: +44 (0) 1509 611511 Telefax: +44 (0) 1509 612345 E-mail: Sales@bem.fki-eng.com

1. RATING DETAILS

1.1	Frame size	BDAX 7-290ER
1.2	Terminal voltage	13.80 kV
1.3	Frequency	60 Hz
1.4	Speed	3600 RPM
1.5	Power factor	0.850
1.6	Applicable national standard	ANSI C50.14
1.7	Rated air inlet temperature	15.0 °C
1.8	Rated output	60.500 MW, 71.176 MVA

2. PERFORMANCE CURVES

2.1	Output vs air inlet temperature	H.E.P. 17660
2.2	Reactive capability diagram	H.E.P. 17661
2.3	Efficiency vs output	H.E.P. 17662
2.4	Open and Short circuit curves	H.E.P. 17663
2.5	Permitted duration of negative sequence current	H.E.P. 1216

3. REACTANCES

3.1	Synchronous reactance, $X_{d(i)}$	235%
3.2	Saturated transient reactance, $X'_{d(v)}$	20.0 % ±15.0 %
3.3	Saturated sub transient reactance, $X''_{d(v)}$	14.4 % ± 15.0 %
3.4	Unsaturated negative sequence reactance, $X_{2(i)}$	17.6 %
3.5	Unsaturated zero sequence reactance, $X_{o(i)}$	9.5 %
3.6	Short circuit ratio	0.47

Notes:

1. The electrical details provided are calculated values. Unless otherwise stated, all values are subject to tolerances as given in the relevant national standards.

Date: 4-Apr-2001

Ref: 110134/16/612S/112R

BRUSH ELECTRICAL MACHINES LTD

ELECTRICAL DATA SHEET - CONTINUATION

BDAX 7-290ER , 60.500 MW, 0.850 pf, 13.80 kV, 60 Hz

4. RESISTANCES AT 20°C

4.1	Rotor resistance	0.138 ohms
4.2	Stator resistance per phase	0.0033 ohms

5. TIME CONSTANTS AT 20°C

5.1	Transient O.C. time constant, T'_{do}	9.7 seconds
5.2	Transient S.C. time constant, T'_{d}	0.66 seconds
5.3	Sub transient O.C. time constant T''_{do}	0.05 seconds
5.4	Sub transient S.C. time constant, T''_{d}	0.04 seconds

6. INERTIA

6.1	Moment of inertia, WR^2 (See note 2)	990 $Kg.m^2$
6.2	Inertia constant, H	0.99 kW.secs/KVA

7. CAPACITANCE

7.1	Capacitance per phase of stator winding to earth	0.18 Microfarad

8. EXCITATION

8.1	Excitation current at no load, rated voltage	325 amps
8.2	Excitation voltage at no load, rated voltage	44 volts
8.3	Excitation current at rated load and P.F.	952 amps
8.4	Excitation voltage at rated load and P.F.	185 volts
8.5	Inherent voltage regulation, F.L. to N.L.	35 %

Notes:

1. The electrical details provided are calculated values. Unless otherwise stated, all values are subject to tolerances as given in the relevant national standards.

2. The rotor inertia value may vary slightly with Generator/turbine interface. In the event of conflict, the figure quoted on the rotor geometry drawing takes precedence.

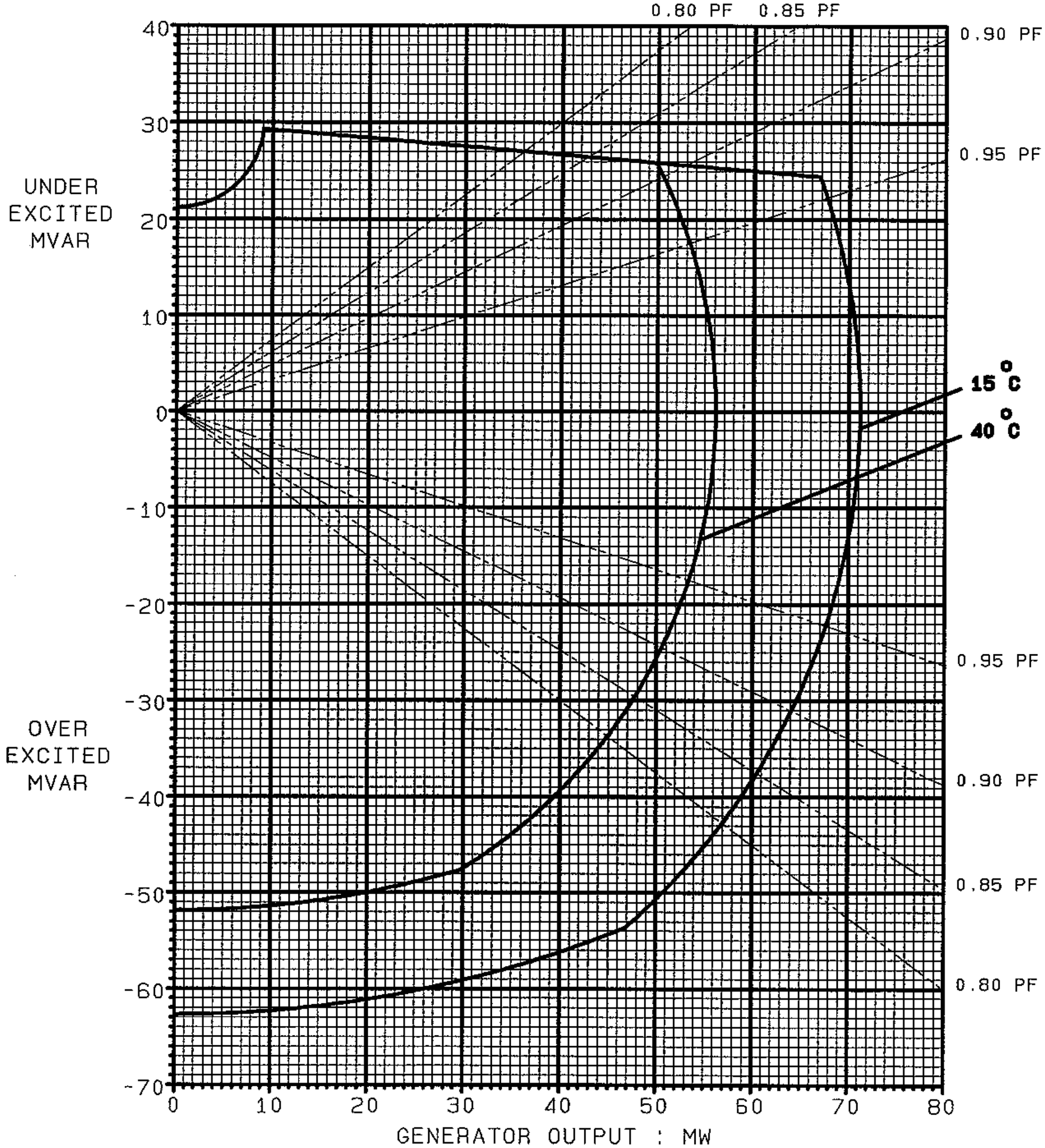
Date: 4-Apr-2001

Ref: 110134/16/612S/112R

Page: 2 of 2

BRUSH ELECTRICAL MACHINES LTD. H.E.P 17661

GENERATOR CAPABILITY DIAGRAM



BDAX 7.290R
13.80KV, 3Ph, 60.Hz.

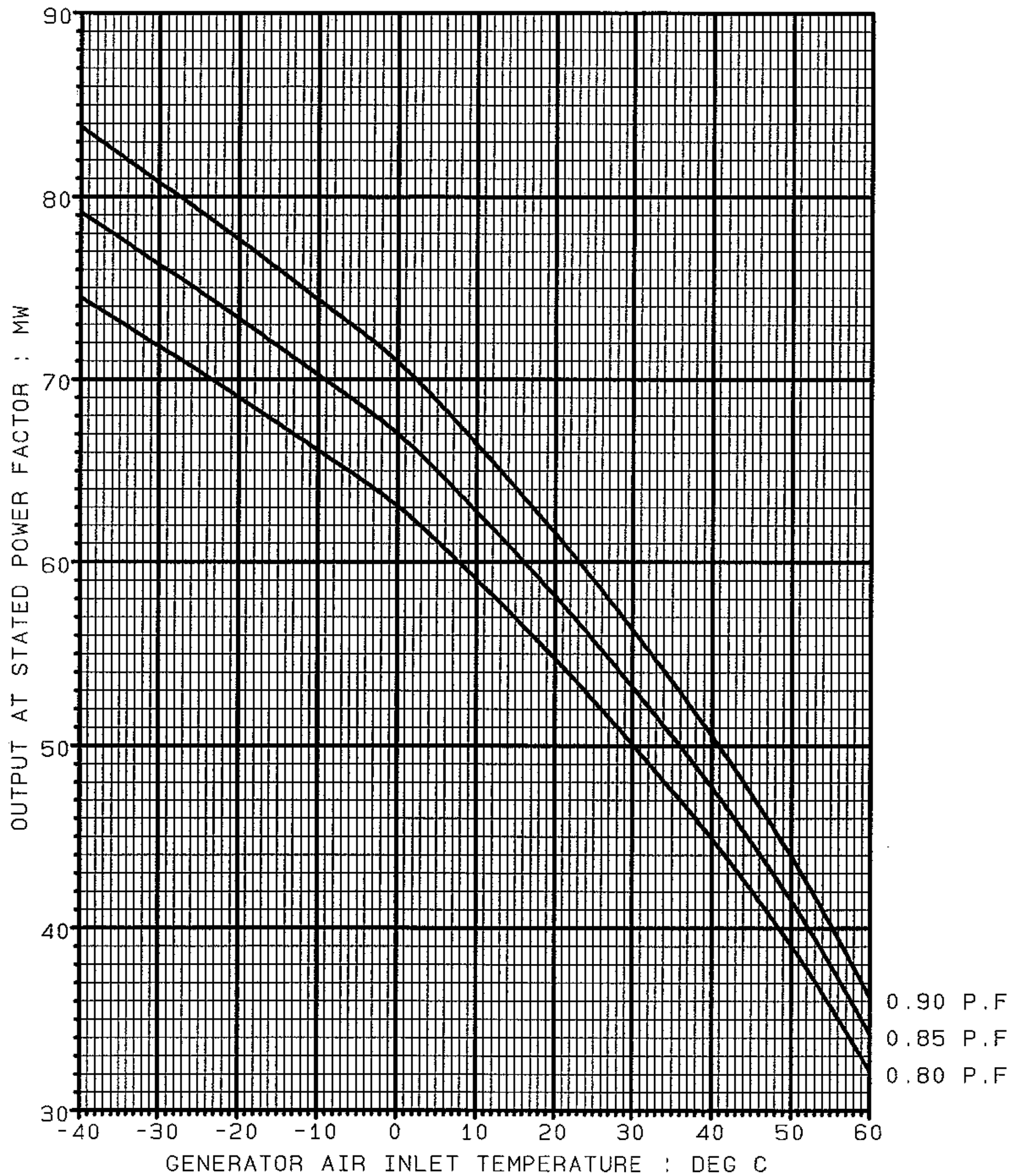
Up to 1000. meters ASL

IN ACCORDANCE WITH
ANSI C50.14.
Class B temperatures.
Curves show base outputs.
Peak outputs are 8% higher.

Issue No. 1: 9-Nov-2000

BRUSH ELECTRICAL MACHINES LTD. H.E.P 17660

VARIATION OF GENERATOR OUTPUT WITH AIR INLET TEMP

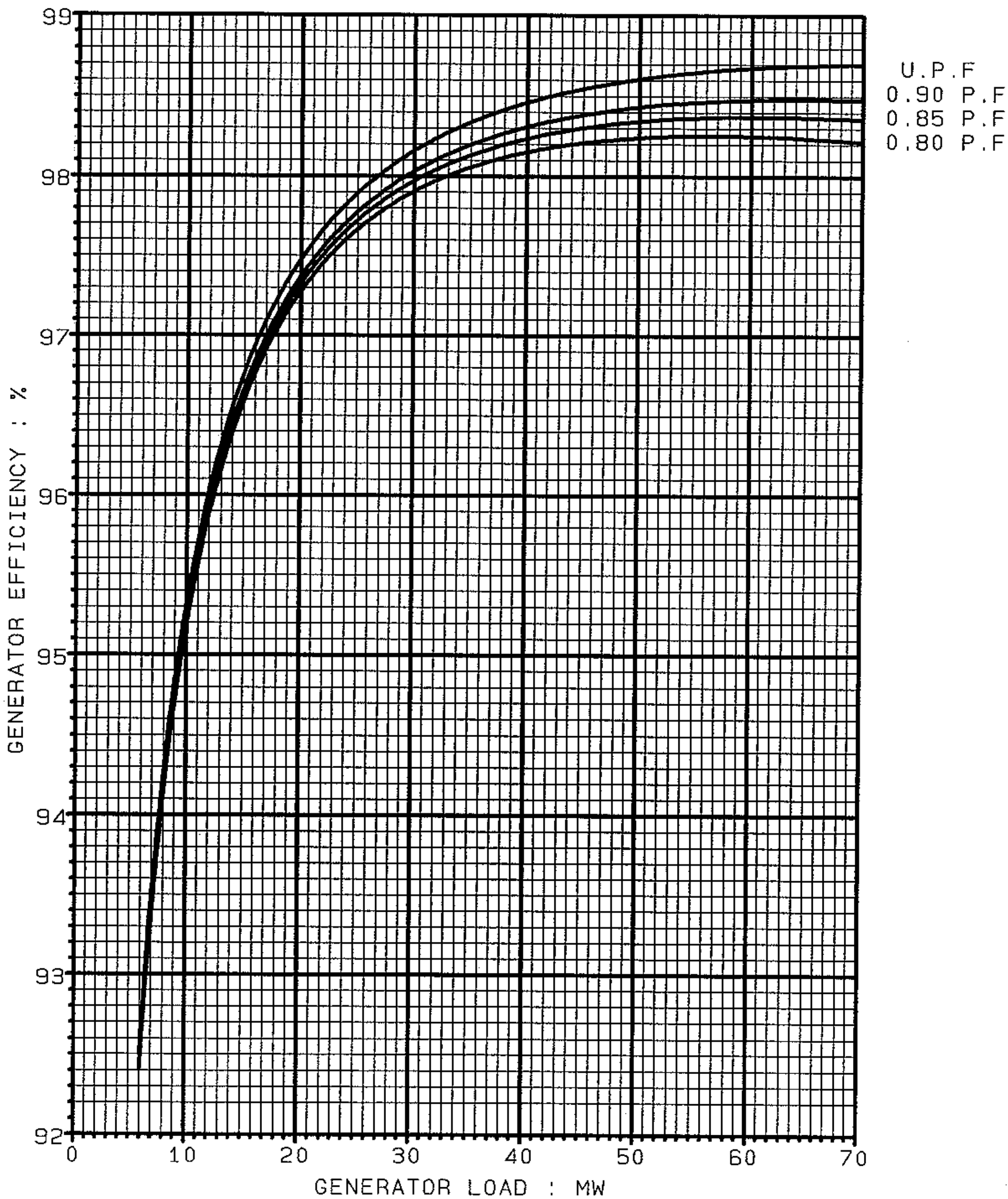


BDAX 7.290R	IN ACCORDANCE WITH
13.80KV, 3Ph, 60.Hz.	ANSI C50.14.
	Class B temperatures.
Up to 1000. meters ASL	Curves show base outputs.
	Peak outputs are 8% higher.

Issue No. 1: 9-Nov-2000

BRUSH ELECTRICAL MACHINES LTD. A.E.P 17662

VARIATION OF GENERATOR EFFICIENCY WITH LOAD



BDAX 7.290R
13.80KV, 3Ph, 60.Hz.

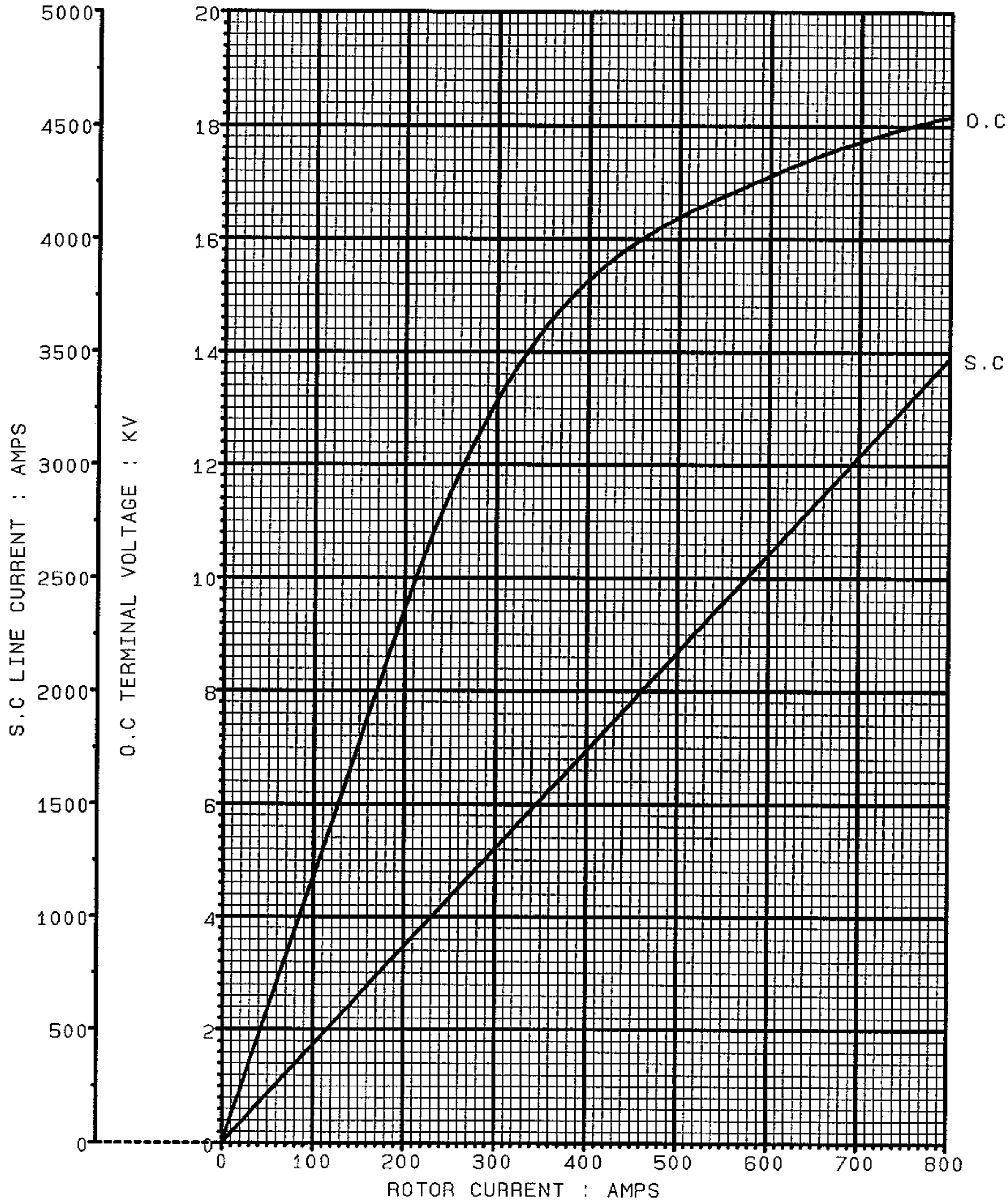
Efficiencies shown are calculated and subject to tolerance as I.E.C 34.1

Minimum efficiencies are 0.1(100-calculated efficiency)% lower.

Issue No. 1: 9-Nov-2000

BRUSH ELECTRICAL MACHINES LTD. H.E.P 17663

OPEN CIRCUIT AND SHORT CIRCUIT CHARACTERISTIC



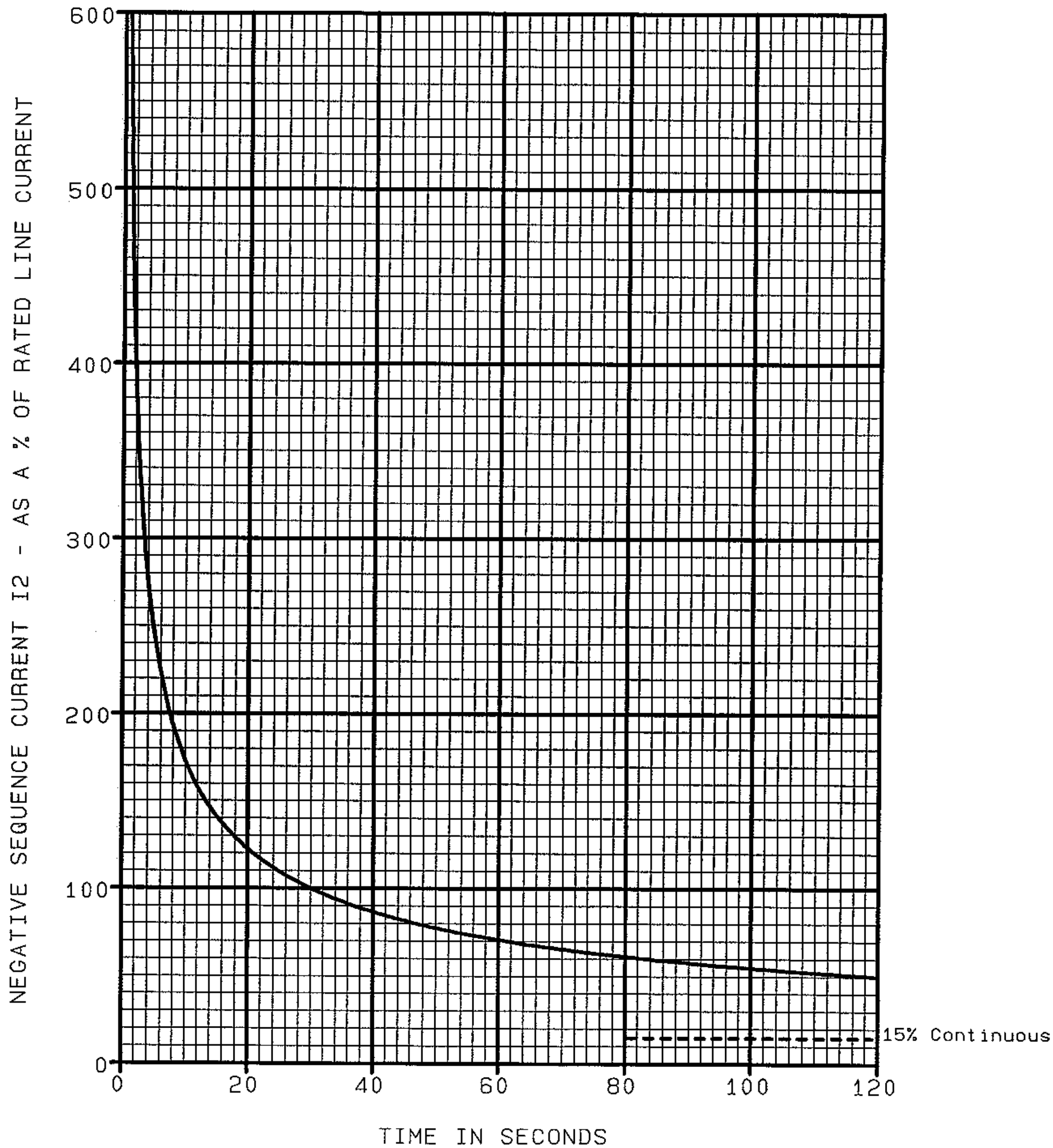
BDAX 7-290R
3Ph, 60.Hz, 3600. RPM.

Issue No. 1: 9-Nov-2000

BRUSH ELECTRICAL MACHINES LTD. H.E.P 1216

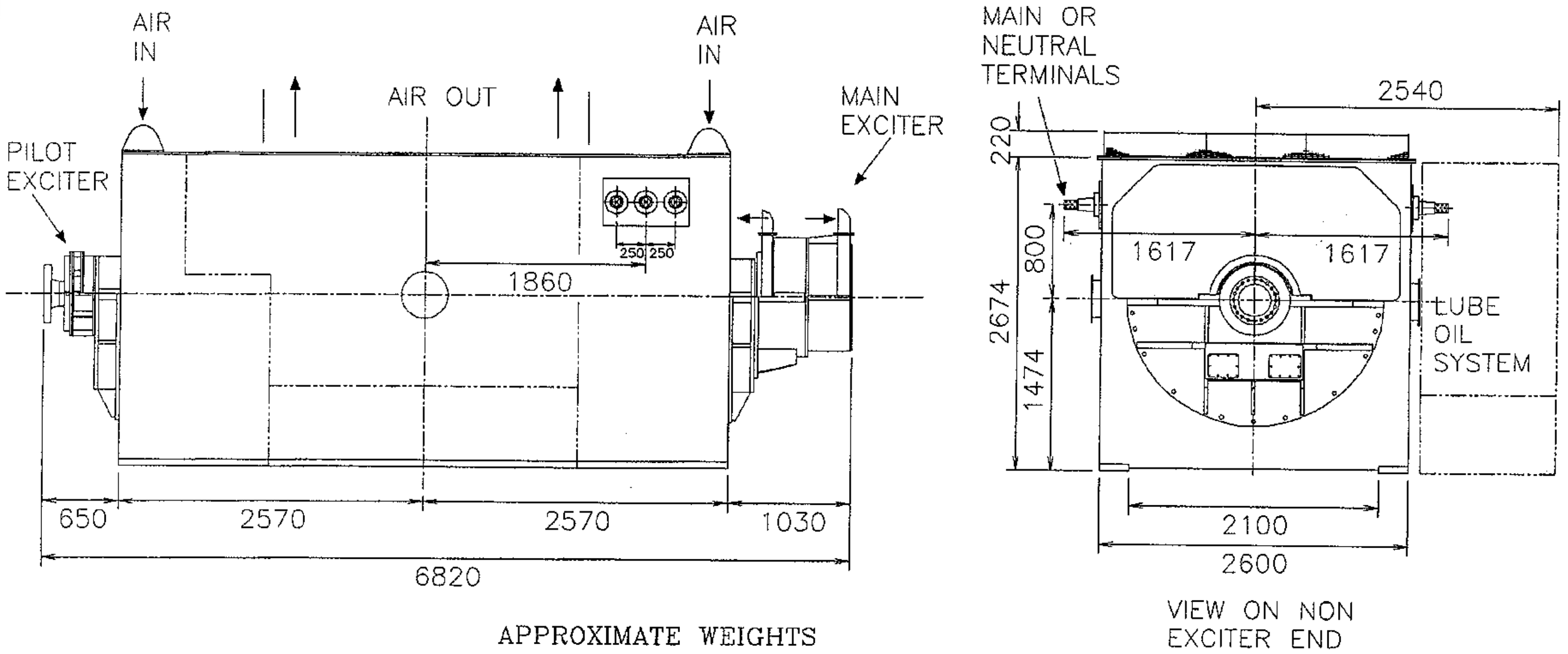
PERMISSIBLE DURATION OF NEGATIVE SEQUENCE CURRENT

$$I_2^2 t = 30$$



NOTE: For continuous operation rated current must not be exceeded in any one phase.

Issue No. 9: 25-Feb-1993



APPROXIMATE WEIGHTS

STATOR	=	53340 Kg
ROTOR AND EXCITER ARMATURE	=	14970 Kg
TOTAL GENERATOR	=	74810 Kg
OIL SYSTEM	=	2200 Kg (DRY)

BRUSH
BRUSH ELECTRICAL MACHINES
P.O. BOX 18 LOUGHBOROUGH LEICESTERSHIRE LE11 1HJ

DATE	17/11/97	DR'N	A NEEDHAM
CIRCULATION	N/A		
ADDL PRINTS	NONE		
AUTOSKETCH	SHT 1 OF 1		

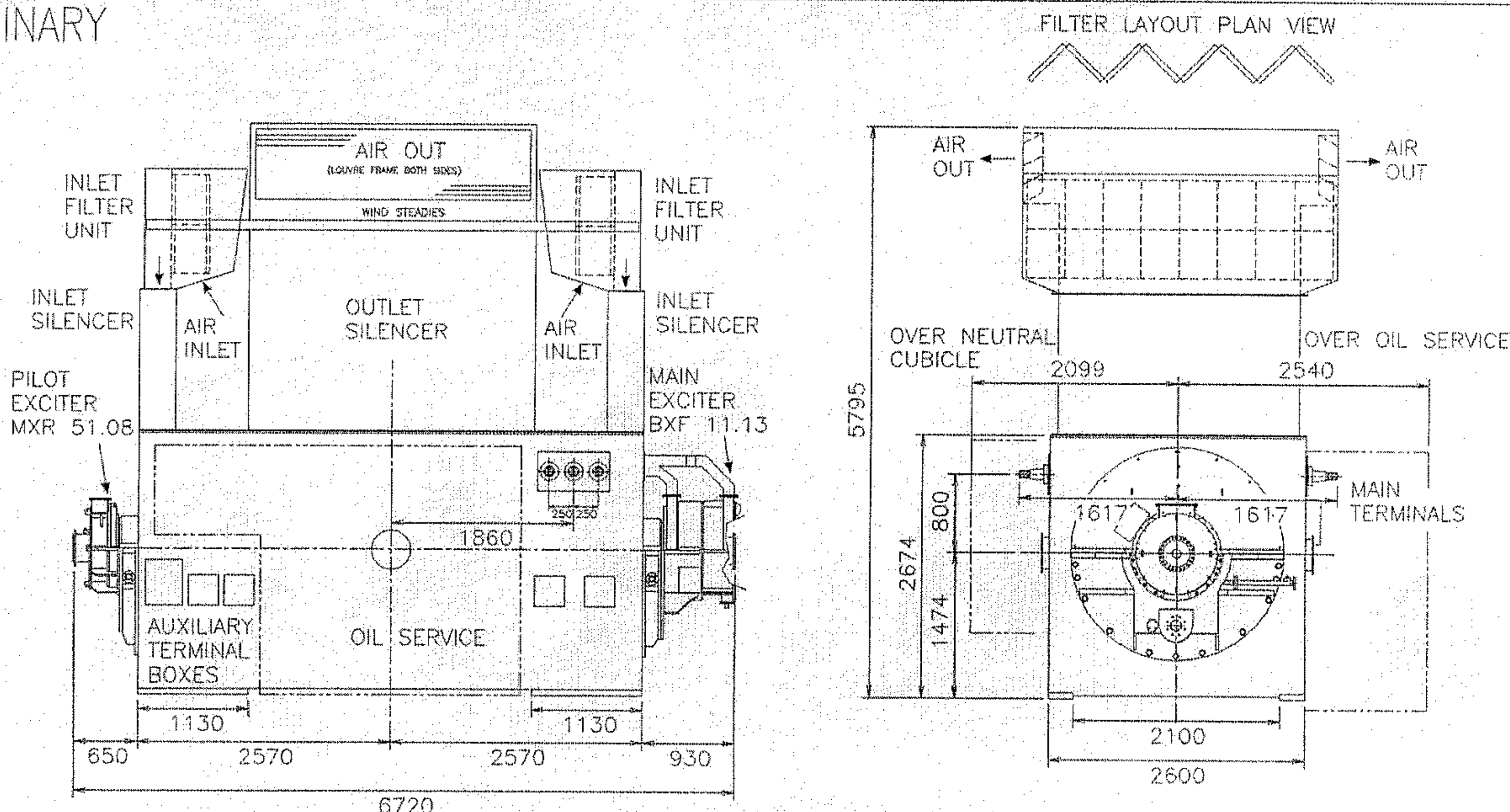
TENDER OUTLINE
BDAX 7-290 E(R)

CODE

ET 2049			ISS A
SCALE	NTS	DEPT	DAX

FIRST ANGLE PROJECTION

PRELIMINARY



APPROXIMATE WEIGHTS

STATOR	=	53840 Kg
ROTOR AND EXCITER ARMATURE	=	14822 Kg
TOTAL GENERATOR ONLY	=	73360 Kg
LUBE OIL MODULE (DRY)	=	2200 Kg
FILTERS & DUCTS (ALL)	=	4500 Kg

BRUSH
BRUSH ELECTRICAL MACHINES LTD
P.O. BOX 18 LOUGHBOROUGH LEICESTERSHIRE LE11 1HJ

ORIGINALLY DRAWN			
DATE	14/12/00	SIG	A N
LATEST MODIFICATION			
DATE	__/__/00	SIG	_ _ _
AUTOSKETCH	SHT 1 OF 1		

TENDER OUTLINE
BDAX 7-290ER

CODE

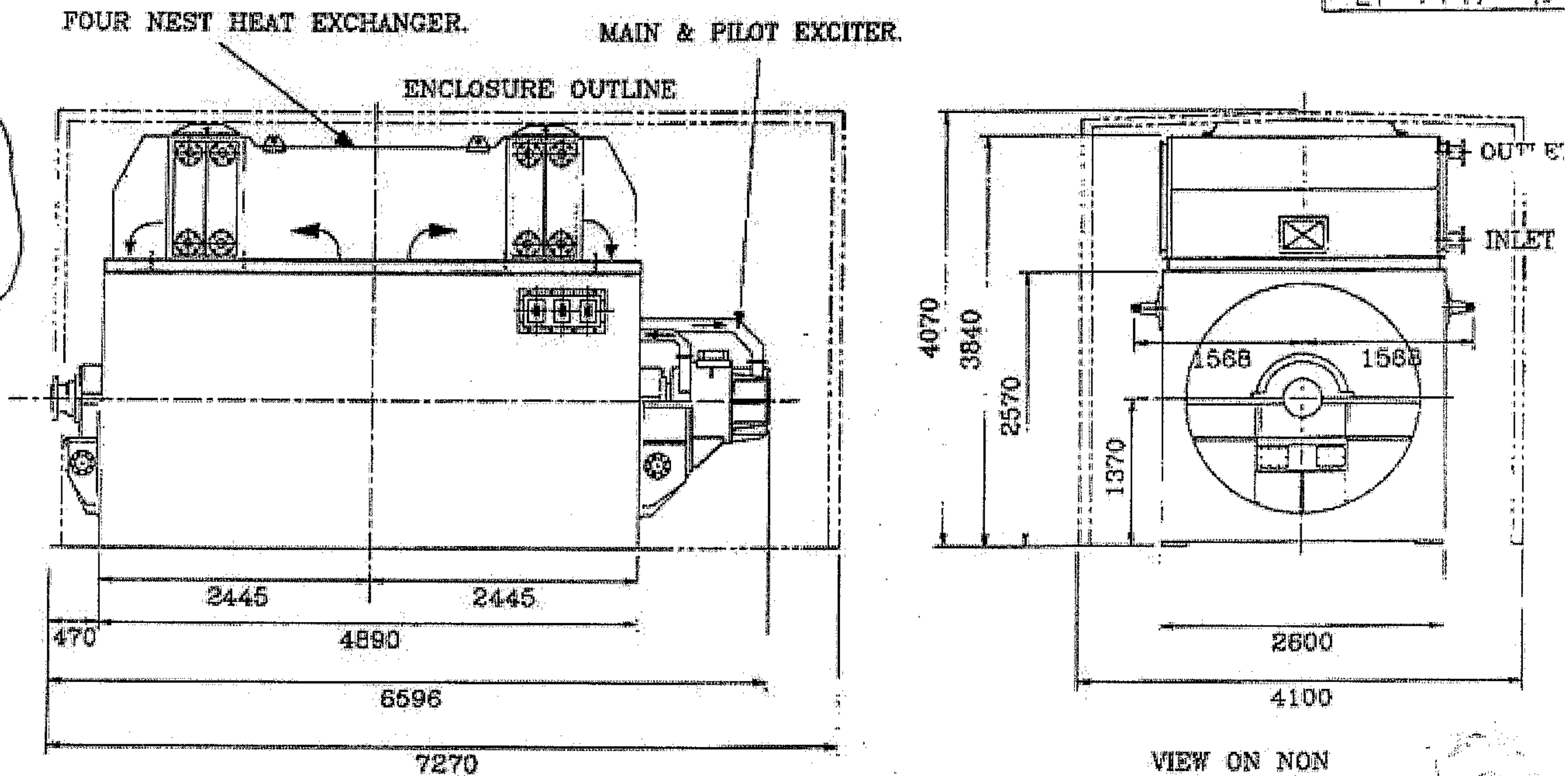
ET 2541 ISS A

SCALE	NTS	DEPT	ENG

FIRST ANGLE PROJECTION

Shorter frame - shows enclosure/canopy only!

ET 1147



BDAX 7-265E(R)H

TENDER OUTLINE

APPROXIMATE WEIGHTS

STATOR	=	50590 Kg
ROTOR AND EXCITER ARMATURE	=	13461 Kg
TOTAL GENERATOR	=	73890 Kg
TOTAL ENCLOSURE	=	10400 Kg

ET 1147 A

A NEEDHAM 12/11/91

BRUSH

INTERNATIONAL SALES & SUPPORT LOCATIONS

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Malaysia
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Fax: +60 3 7039625
Email: fkiasia@po.jaring.my

FKI China

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Fax: +86 21-52375079
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BRUSH

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Fax: +31 180 445866
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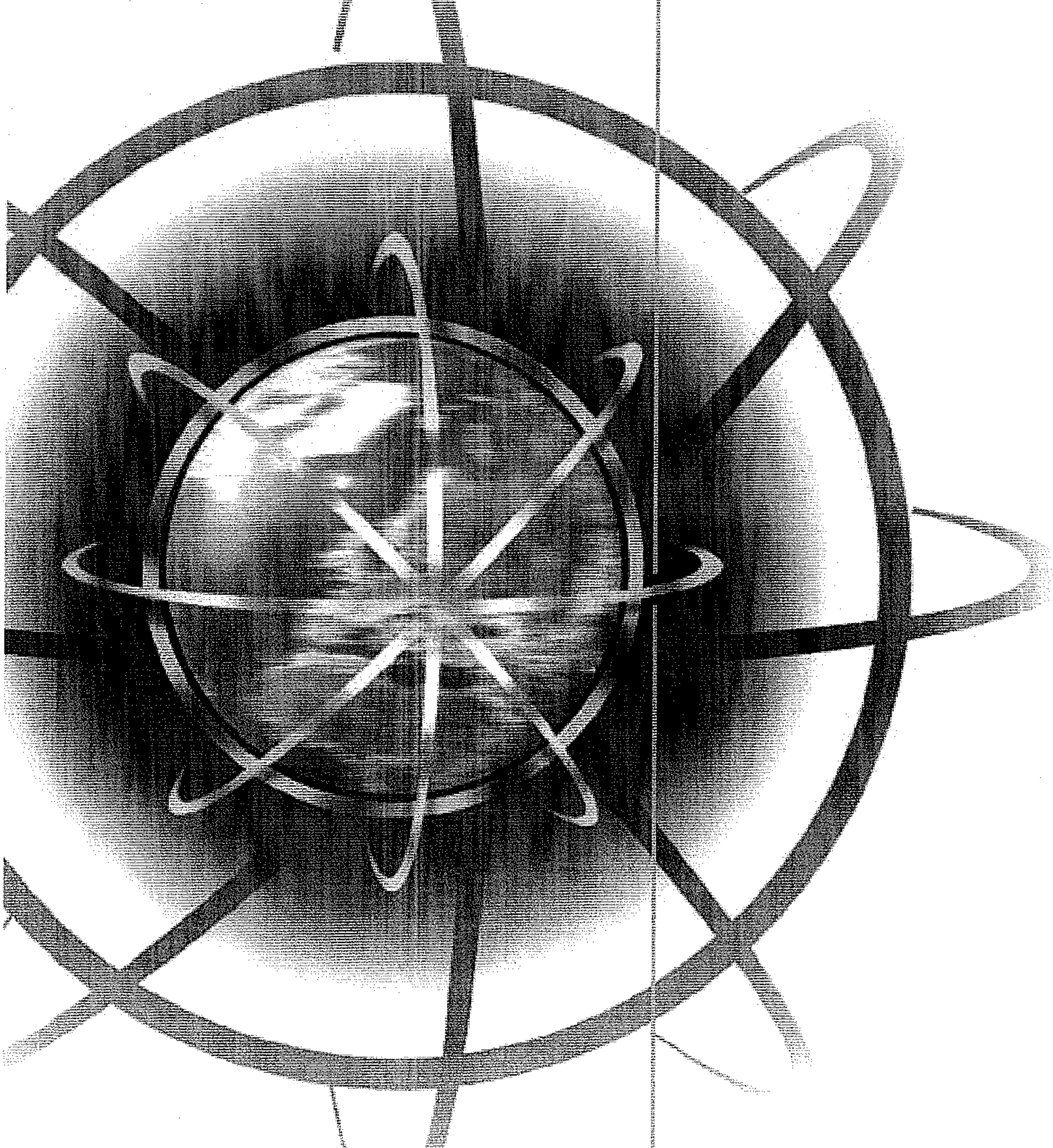
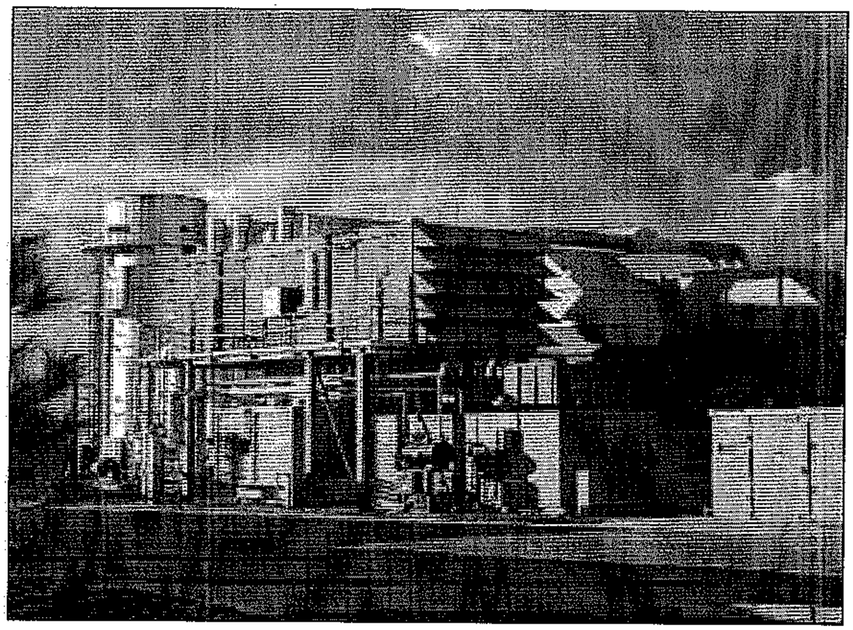
BRUSH TURBOGENERATORS

Industrial Power

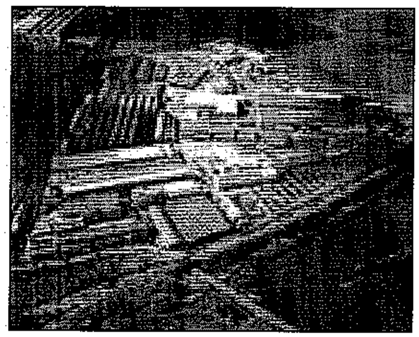


BRUSH

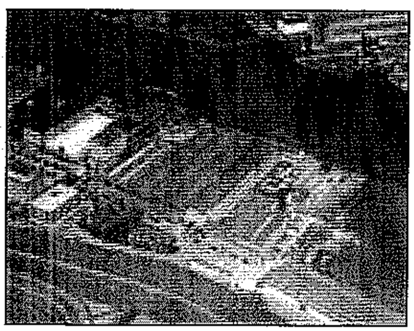
COMPANY BACKGROUND



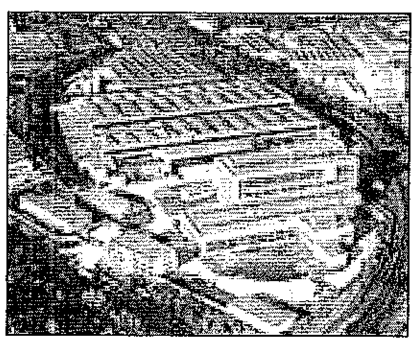
Right: One of four 60MW gas turbine driven BRUSH turbogenerators at a cogeneration installation in the USA.



BRUSH Electrical Machines, Loughborough, England



BRUSH HMA, Ridderkerk, Netherlands



BRUSH SEM, Plžen, Czech Republic

With activities worldwide, over $2.3 billion of annual sales and more than 13,000 employees, FKI is a significant player in the global energy market.

The BRUSH Turbogenerator Division of FKI Energy Technology combines the resources of three of the world's major manufacturers of generators for gas turbine, steam turbine and hydro turbine drive.

BRUSH Electrical Machines Ltd is located at Loughborough in the UK and is designated as FKI Energy Technology's Centre of Excellence for the design and manufacture of power management systems and air cooled 2-pole turbogenerators up to 150MVA.

BRUSH HMA bv, located at Ridderkerk in the Netherlands, is the designated Centre of Excellence for 4-pole generators with ratings between 10MVA and 65MVA.

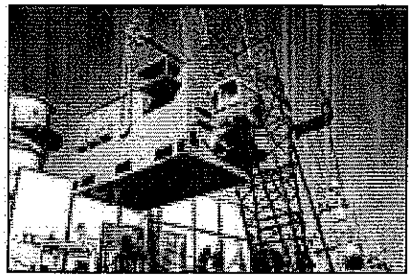
BRUSH SEM sro, located at Plzen in the Czech Republic, is the designated Centre of Excellence for air cooled 2-pole turbogenerators above 150MVA, hydrogen cooled generators and hydrogen/water cooled generators up to 1100MVA and the refurbishment of hydro generators up to 355MVA.

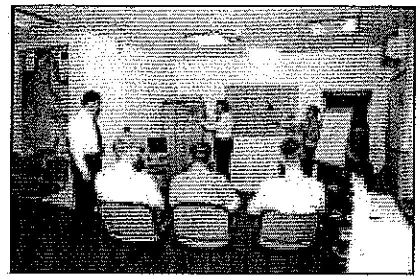
The three companies have a combined total of over 300 years' experience in the design and manufacture of electrical equipment for industrial, marine and offshore applications, backed by modern research and development facilities.

The BRUSH Turbogenerator Division provides a complete electrical service to all sectors of the energy industry. From a product portfolio encompassing generators for base load or intermittent duty, power management systems and fully co-ordinated packages of electrical equipment, BRUSH Turbogenerators can provide equipment and services to meet the most demanding specifications.

All equipment complies with the relevant European, American and International standard specifications. In addition, all three companies are registered to ISO9001:2000, which governs the quality of design, manufacture and service. The requirements needed to obtain and maintain this registration have become a cornerstone of management philosophy.

AFTER SALES SERVICE & TRAINING





WORLDWIDE SERVICES PROVIDED BY BRUSH

- Supervision of installation
- Commissioning
- Cleaning and inspection
- Rewinds
- Overhaul and refurbishment
- Power management upgrades
- Spare parts
- Repair of any type of rotating electrical machine
- Re-engineering

FULLY DOCUMENTED TRAINING COURSES PROVIDED BY BRUSH

- PRISMIC power systems
- BRUSH AVR equipment
- Mechanical inspections
- Operator courses
- Maintenance courses
- Protection systems

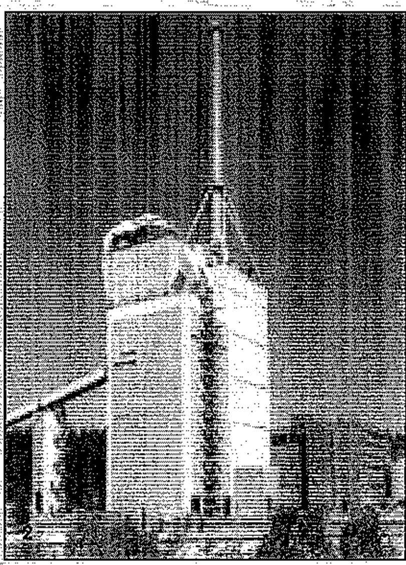
BRUSH

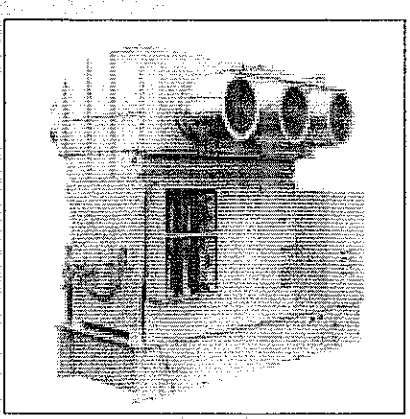
COMBINED HEAT AND POWER/COGENERATION

1. Walt Disney World, Orlando, Florida, USA, where a gas turbine, driving a BRUSH generator, is contributing 35MW of electrical power, along with steam for space heating and air conditioning absorption chillers, to the enormous energy demand of the 28000 acre site. © *The Walt Disney Company.*

2. Lahden Lämpövoima Oy's Kymijärvi Power Station in Finland, where a Frame 6 gas turbine driven 40MW BRUSH 2-pole generator contributes to electricity and district heating requirements for the town of Lahti.

3. BRUSH 4-pole turbogenerator for the EPC Abener bioethanol plant in La Coruna, Spain.





A combined heat & power (CHP) scheme offers a high efficiency method for the production of both electrical and thermal energy from a single fuel source, with relatively low installation and operating costs. Electrical power is produced by a generator driven by a gas turbine or reciprocating engine, with the prime mover exhaust heat being recovered as steam for a variety of uses, from process heat to district heating for a whole community.

The USA, the world leader in cogeneration, has hundreds of BRUSH generators operating in CHP schemes. Typical of these is the Downtown Government Centre, Dade County, Florida, where a Rolls Royce SK30 gas turbine and a Peter Brotherhood steam turbine, installed in 1985 and both driving BRUSH generators, produce 27.5MW of electrical power. The plant also produces chilled water for air conditioning and 300 gallons per minute of hot water at an overall thermal efficiency in excess of 75%.

For over 15 years, the Central Birmingham Health Authority has been operating a Centrax gas turbine, driving a 3.6MW BRUSH generator, as part of a CHP scheme at the Queen Elizabeth Hospital in Birmingham, UK. In addition to the 3.6MWe of electricity, the plant, the first of its type at a UK hospital, also provides 5.9MWth of steam for space heating and hot water. A further 1.7MWth of heat is recovered through an economiser to preheat boiler feedwater.

EPC Abener installed new generation equipment for a bioethanol galicia cogeneration plant in La Coruna, Spain, for which Rolls Royce Power Engineering supplied an RB211-6562 turbine driving a BRUSH 4-pole turbogenerator. The La Coruna plant produces 126,000m³ per day of bioethanol, a fuel obtained by processing and distilling fermented biomass. The bioethanol is used as an additive to petrol and diesel oil for use in combustion engines, where it offers the advantages of increased output and improved efficiency. As a renewable energy source, bioethanol contributes to the environment by reducing the use of fossil fuel. The generator was built in 2000 and installation and commissioning were completed by the summer of 2001.

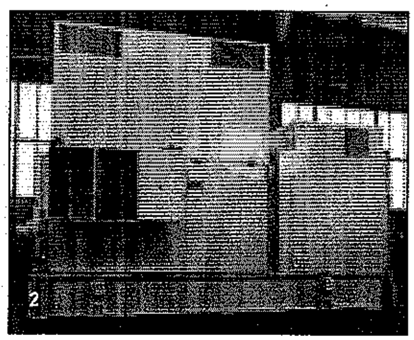
INDUSTRIAL EXPERTISE

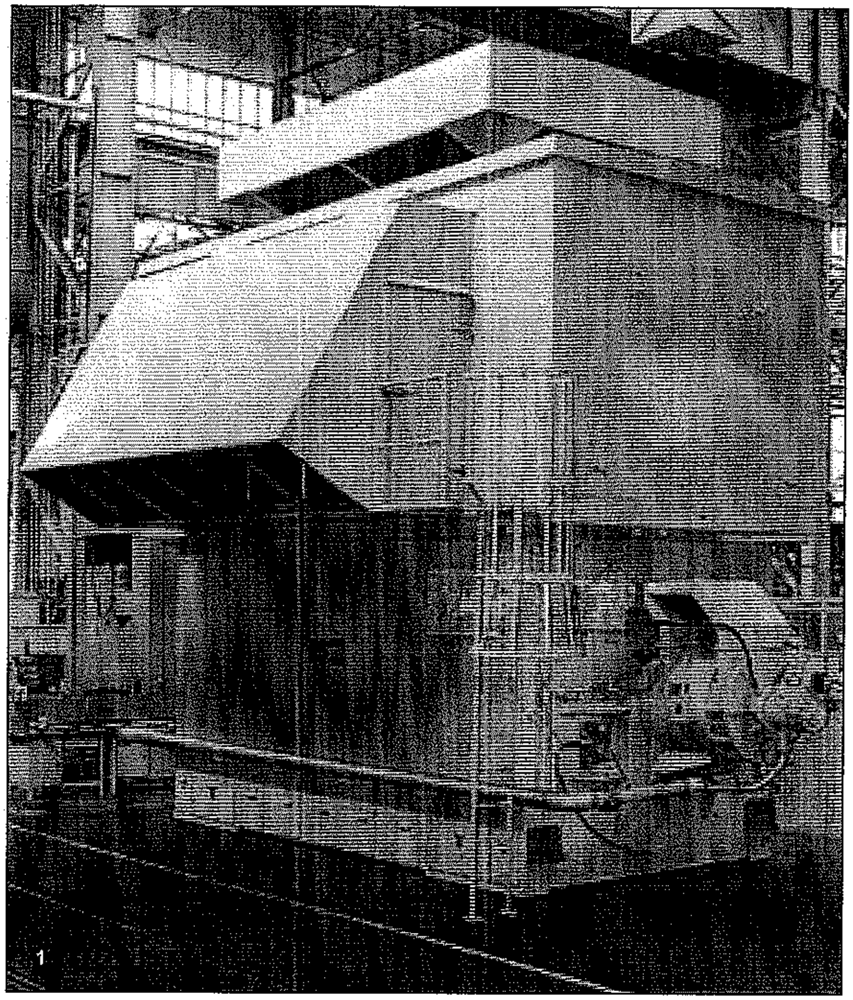
1. BRUSH BDAX 98-330ER 2-pole turbogenerator developed specially for the General Electric LMS 100 aeroderivative gas turbine.

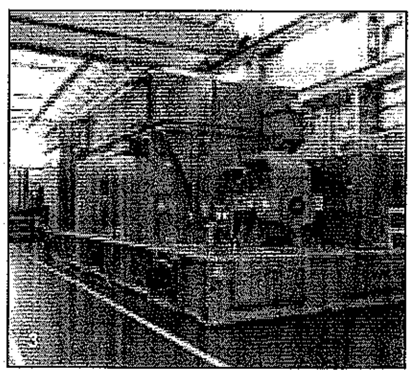
2. Open air cooled BRUSH 4-pole turbogenerator package for gear driven gas turbine drive.

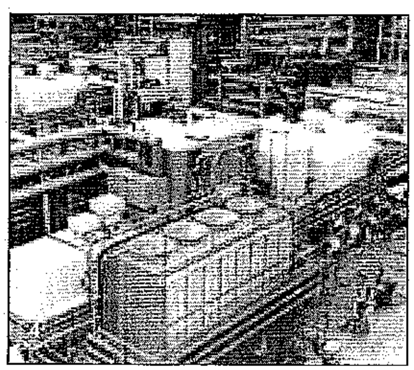
3. One of three gas turbine driven CACW (TEWAC) 40MW BRUSH 2-pole turbogenerators supplied to an oil refinery in Thailand.

4. One of eight 147MW BRUSH 2-pole turbogenerators and auxillary packages installed at Teesside Power Station, UK.









The BRUSH Turbogenerator Division can provide a proven solution for electrical equipment packages selected from the following:

- Air cooled 2-pole turbogenerators up to 300MVA for gas turbine and steam turbine drive.
- Hydrogen and hydrogen/water cooled 2-pole turbogenerators up to 1100MVA for gas turbine and steam turbine drive.
- Salient pole 4-pole turbogenerators up to 65MVA for gas turbine and steam turbine drive.
- Power management and excitation control equipment.
- Comprehensive "round the clock" service capability, including full refurbishment of salient pole multipole generators up to 355MVA for hydro turbine drive and the repair of any make of electrical machine.

Other companies within FKI Energy Technology complete an electrical project capability by providing:

- HV and LV switchboards.
- Transformers.
- Motors.

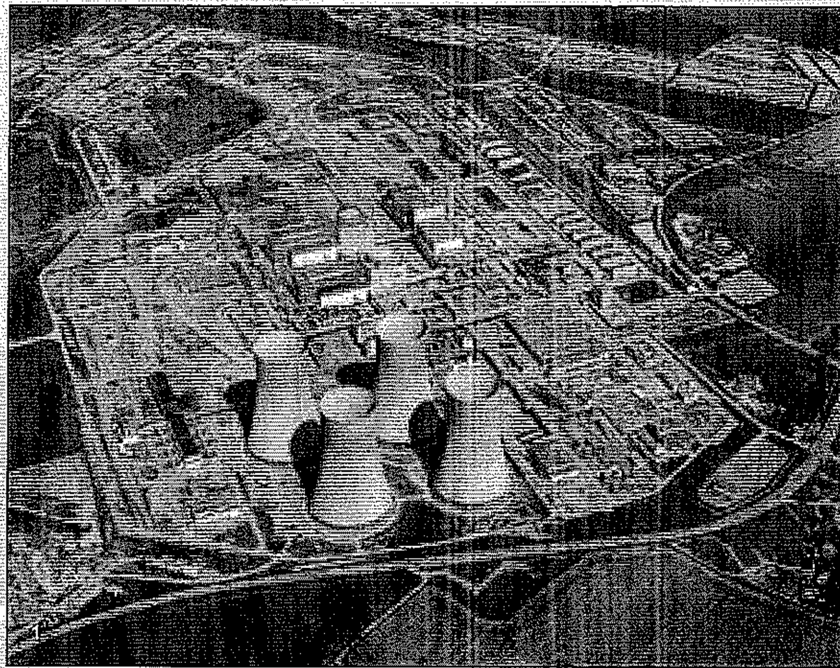
UTILITIES AND INDEPENDANT POWER PRODUCERS

1. Temelin Power Station, Czech Republic, where two BRUSH combined cooled 2-pole turbogenerators have been producing 2000MW of base load electricity since 2002.

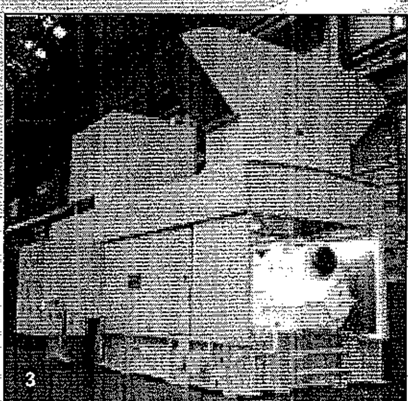
2. Parkeston Power Station, Western Australia, comprising three IHI LM6000 gas turbines driving BRUSH generators.

3. One of five BRUSH 2-pole turbogenerators at Enemalta Corporation's Delimara Power Station, Malta.

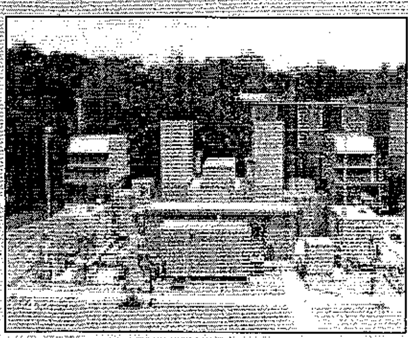
4. Pratt & Whitney Power Systems 50MW FT8 "Twin Pac", incorporating a double end drive BRUSH 2-pole generator, at La Dorada, Columbia.



2



3



Since providing two 3000kW steam turbine driven generators to the Midland Electricity Corporation in 1912, and heralding the birth of municipal power generation, BRUSH has become a major supplier to utilities and independent power producers the world over.

From the USA to New Zealand, BRUSH gas turbine and steam turbine driven DAX 2-pole and DG 4-pole turbogenerators are being operated on base load and peak load duty and also as synchronous compensators.

For large scale thermal and nuclear power generation, BRUSH has supplied almost 200 high output 2-pole turbogenerators using hydrogen and combined hydrogen-water cooling systems. These generators are designed to be driven by both gas and steam turbines, the design and characteristics being the result of an in-depth knowledge, gained from BRUSH's extensive experience, and the latest design techniques, backed by modern manufacturing methods and plant.

Above 300MVA, hydrogen and combined cooled generators give the advantages of:

- Reduced weight of components.
- More economical operation, in particular under partial load conditions.
- Improved efficiency as a result of significantly reduced ventilation losses.
- Extended insulation life.

Combined cooled machines are available up to 1100MVA.

In 1996, two BRUSH DG 4-pole generators, driven by Frame 5 gas turbines, were commissioned for standby operation at Guernsey Power Station in the UK. Since then, BRUSH has supplied over 150 4-pole generators for a variety of applications, including LM2500, LM2500+, LM6000, Frame 6, RB211 and H25 gas turbines.

1. 10.7MW BRUSH generator at Norsk Hydro's fertilizer plant in Immingham, UK.

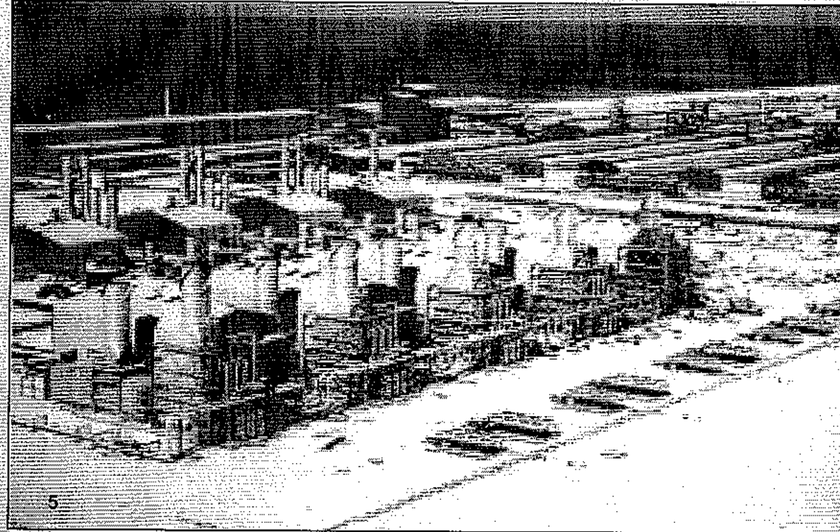
2. A BRUSH generator installed at ICI's No.4 Nitric Acid Plant in the UK.

3. 2.1MW steam turbine driven BRUSH generator at a chemical plant in the UK.

4. Purfleet Board Mill, Essex, UK, generates all the electricity needed for process from a 3.5MW gas turbine and a 7.7MW steam turbine, both driving BRUSH generators.

5. Dubai Aluminium Smelter, Dubai, where 13 gas turbine driven BRUSH 2-pole generators provide over 600MW of electricity for the smelting process.

6. Steam turbine driven, 36MW BRUSH 2-pole generator at a paper mill in Arkansas, USA.

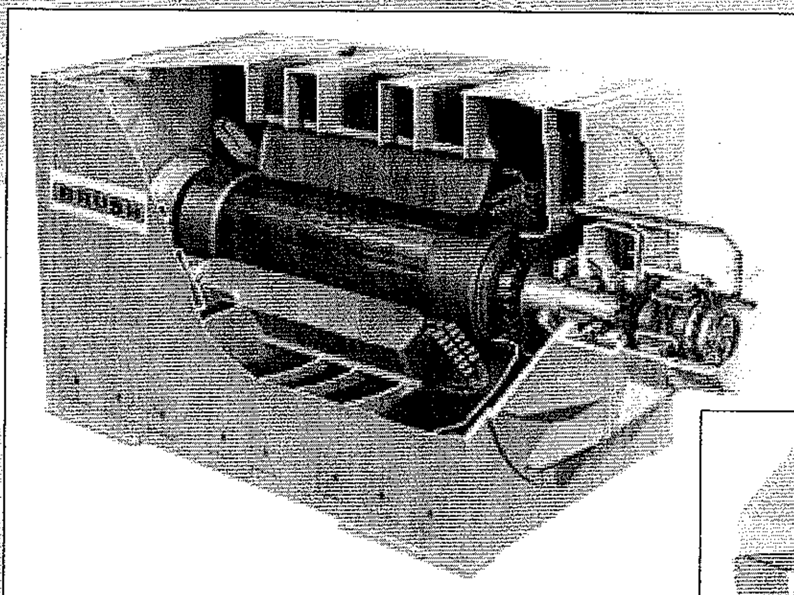


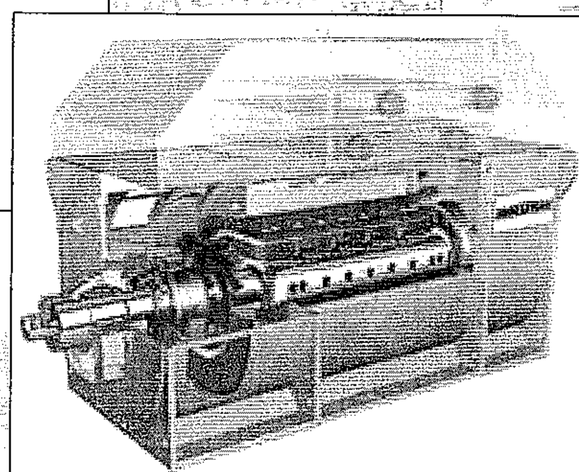
5

6

Some processes, particularly in chemical industries, require a fluctuating thermal energy input, which inevitably leads to energy waste during periods of low demand.

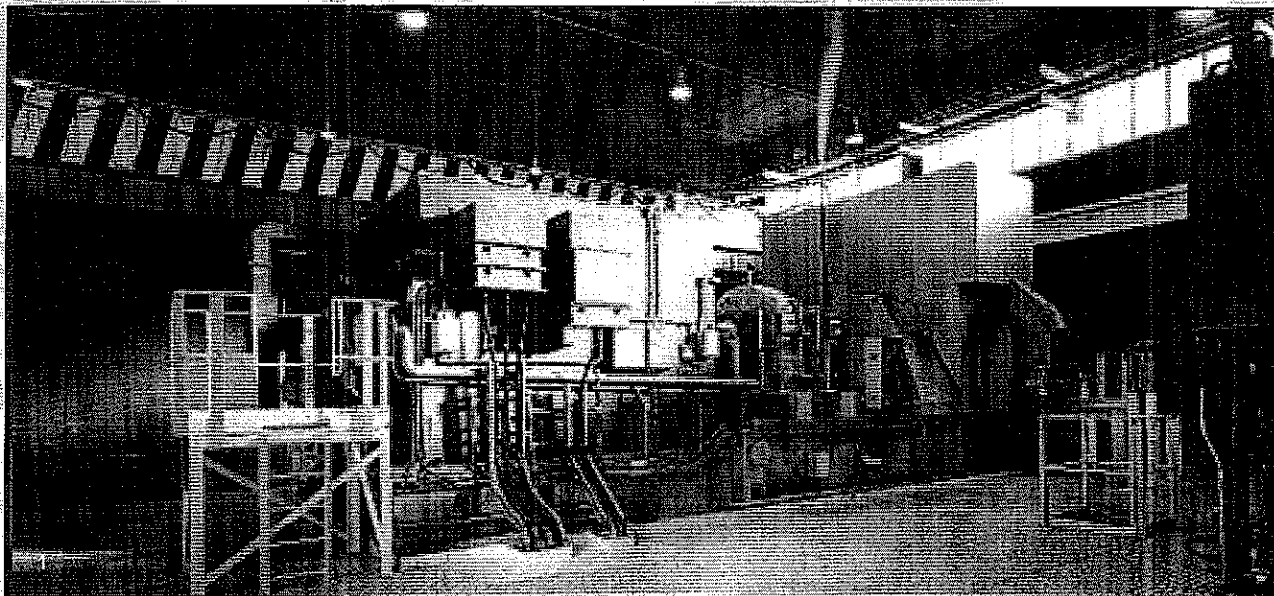
As part of the refurbishment of their No 4 Nitric Acid Plant at Billingham in the UK, ICI installed a 30MW BRUSH generator in a new production train. By designing the train to operate at constant speed, up to 23MW of electrical energy is recovered during the acid production process.

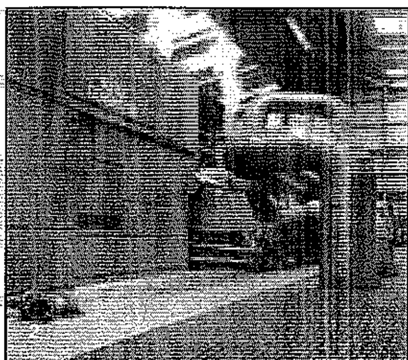




Cutaway views of a BRUSH 2-pole DAX turbogenerator (above) and a BRUSH 4-pole DG turbogenerator (right).

PROCESS INDUSTRIES

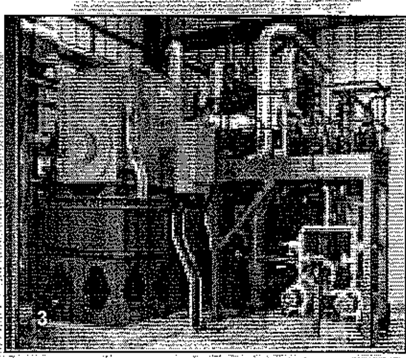




All over the world, BRUSH synchronous generators are supplying essential power to industry.

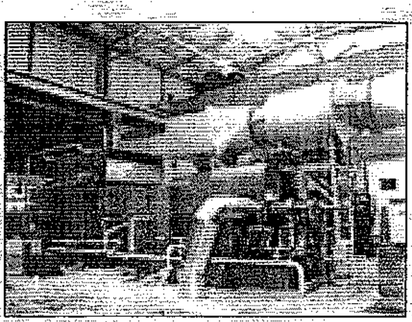
In 1990, a 16MW BRUSH 4-pole generator, manufactured in the Ridderkerk factory, was incorporated into the world's first LM1600 gas turbine package at Hoogovens Steel's Ijmuiden plant in the Netherlands. Since then, BRUSH has established a position as the foremost supplier of generators for the LM1600 gas turbine, in industrial, marine and offshore applications.

In 1997, three BRUSH 4-pole generators were ordered by Thomassen International for the Egyptian oil company Bapetco. Each unit was coupled to a General Electric Frame 5 gas turbine rated at 24.5MVA. As the generators are open air cooled and located outside in a desert environment, special attention had to be paid to the cooling air intake. A self-cleaning "pulse clean" filter removes airborne sand particles and allows the generators to operate for extended periods between filter element changes.



On the other side of the world, Chevron, America's largest producer of California reformulated gasoline, has depended on BRUSH power since 1986, when two General Electric Frame 6 gas turbines, driving BRUSH 2-pole generators, were installed at the El Segundo Refinery in Los Angeles, California, USA.

In 1995, the power generation capability of the refinery was extended from 80MW to 130MW, with the addition of a further Frame 6 gas turbine and a 10MW General Electric steam turbine. Again, BRUSH was chosen to provide the generators, both of which were designed to keep the total fault contribution within the limits of the existing distribution system.



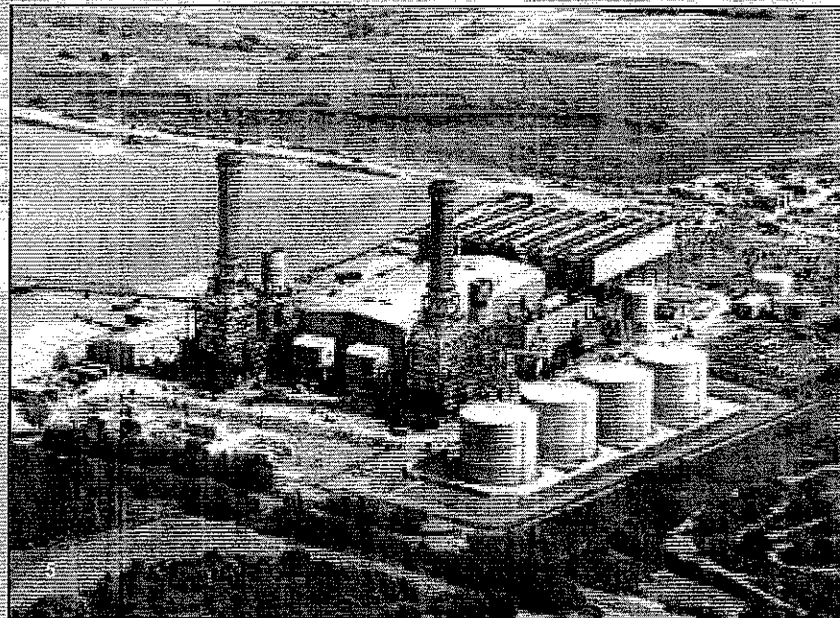
Many industrial processes involve exothermic reactions, from which the heat produced can be harnessed to produce electricity. One such installation is at Norsk Hydro's fertiliser plant at Immingham in the UK, where BRUSH provided two steam turbine driven generators, rated at 10.7MW and 6.1MW, as part of a combined heat and power scheme designed to protect essential supplies to the manufacturing process. To keep within the limitations of the existing distribution system, the generators were designed to have a total combined fault contribution of only 90MVA.

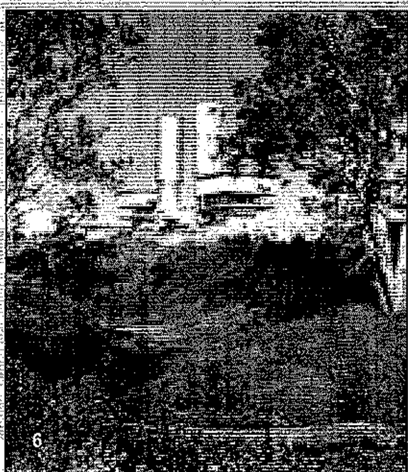
5. Corby Power Station, East Midlands, UK.

6. Mackay Power Station, Queensland, Australia, where two Rolls-Royce gas turbines drive a 40MW double end drive BRUSH 2-pole generator.

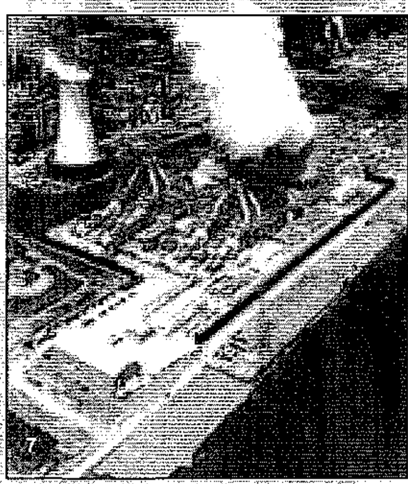
7. Teesside Power Project, UK. At the heart of the power station are eight Siemens-Westinghouse W701 gas turbines, each driving a 147MW BRUSH turbogenerator.

8. Gas turbine driven 38MW BRUSH 4-pole generator at a power station in Greece.



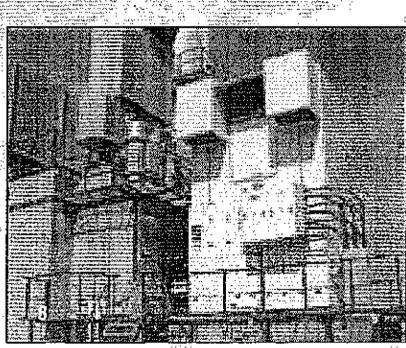


Privatisation of the electricity supply industry in the UK gave rise to the now famous "dash for gas", in which old, inefficient thermal power stations were replaced by high efficiency, gas turbine based stations. A 350MW combined cycle power station, built in 1992 at Corby in the East Midlands, was the first large scale combined cycle power station venture to be undertaken by one of the UK regional electricity companies. Power is provided by two Frame 9E gas turbines and a 115MW steam turbine, each driving a BRUSH DAX generator. BRUSH generators, operated by regional electricity companies and independent power producers, are now providing over 2000MW of base load power to the UK distribution system.



In 1995, three DAX turbogenerators were supplied to Parkeston Power Station, Kalgoorlie, Western Australia, as part of the Goldfields Power Project, a joint venture between TransAlta Energy of Canada and Normandy Power Pty Ltd, a wholly owned subsidiary of Gold Mines of Kalgoorlie Ltd. The generators were ordered by Ishikawajima-Harima Heavy Industries Co Ltd (IHI) of Japan, for LM6000 aero derivative gas turbine drive. The units went into service in early 1996, operating on natural gas from the Goldfields Gas Transmission Pipeline.

Aero derivative gas turbines have proved very popular for medium sized power stations. BRUSH is a principal supplier to Pratt & Whitney Power Systems of Windsor, Connecticut, USA, who package the Pratt & Whitney FT8 gas turbine. Recent installations include 50MW double end drive "Twin Pacs" in the USA, South America, China, Ireland and New Zealand, bringing to over 350 the number of Pratt & Whitney engines in various "Twin Pac" arrangements.



BRUSH was selected to provide four 500MW turbogenerators for the ShenTou bituminous coal-fired power station in the Chinese province of Shan-Xi. The first unit entered service in 1992 and the second in 1993. A contract for the supply of two additional units was signed in 1999; these units will be commissioned into service in 2005.

The two largest turbogenerators produced by BRUSH were supplied to the Temelin nuclear power station in the Czech Republic and are rated at 1100MVA. The first generator was produced in 1993 and the second in 1996. The first generator was commissioned into service in 2000 and the second two years later in 2002.

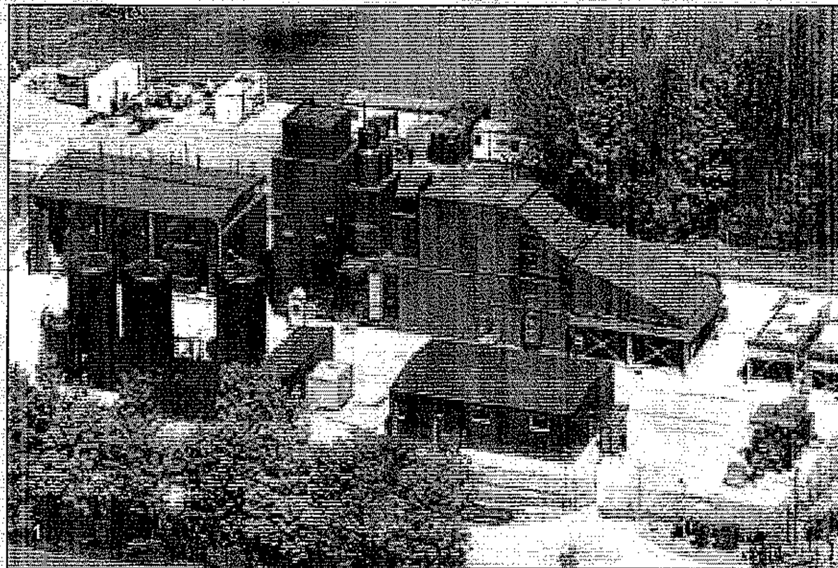
COMBINED CYCLE GAS TURBINE POWER GENERATION

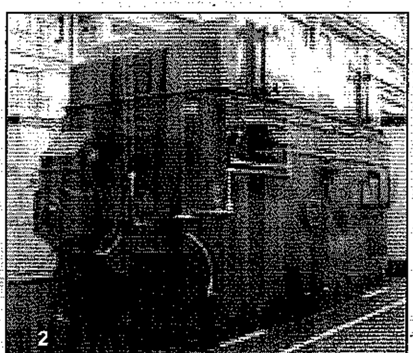
1. Burghfield Power Station, UK, incorporating an LM6000 gas turbine driving a BRUSH 2-pole generator

2. BRUSH 2-pole 50MW generator for gas turbine drive.

3. BRUSH 4-pole 13MW steam turbine generator at Horsens Power Station, Denmark.

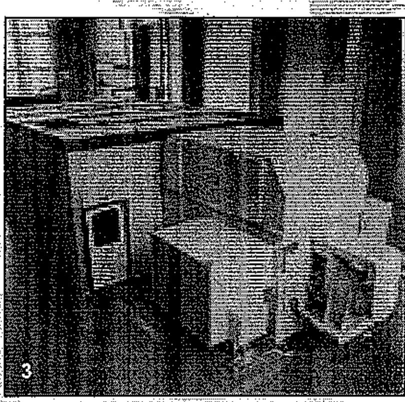
4. Generator capability chart displayed on the operator's VDU of the BRUSH PRISMIC power management system.





In December 1991, a BRUSH 2-pole turbogenerator left the company's factory at Loughborough for incorporation into the world's first LM6000 gas turbine generation package. This was followed by a further two units in early 1992. Subsequently, BRUSH has built over 300 generators for LM6000 gas turbine drive.

The first three generators were built into pre-assembled and fully factory tested gas turbine/generator packages by Stewart & Stevenson (now GE Aero Energy Products) of Houston, USA. Delivered to Canada, the units are based at two sites, both of which are owned and operated by TransAlta Resources Corporation, a subsidiary of TransAlta Utilities Corporation, one of Canada's largest developers of electric power projects.



The first of these plants, at the Ottawa Health Science Centre in Ontario, consists of one LM6000 gas turbine generator set running on natural gas and producing 42MW of electricity. The other two LM6000 units are installed at Boeing's facility in Mississauga, also in Ontario. At each plant, the gas turbine waste heat is recovered to produce an additional 32MW of electricity through an ABB steam turbine driving a BRUSH 2-pole generator.

In early 1997, the Godovari Gas Power Project, at Kakinada, India, became fully operational. The power station, which was built by consortium partners Rolls-Royce/Parsons and Westinghouse Power Generation, was the first independent power project in India to enter commercial operation. The installation comprises three Siemens Westinghouse W251 gas turbines, driving BRUSH 2-pole generators, operating in combined cycle with a 70MW steam turbine.

BRUSH's involvement in Indian independent power projects has continued with the installation in 2004 of two 100MW steam turbine driven generators, one at Indal's Hirakud Works in Sambalpur and one at the Jindal Thermal Power Company's South West Power Plant at Tornagallu.

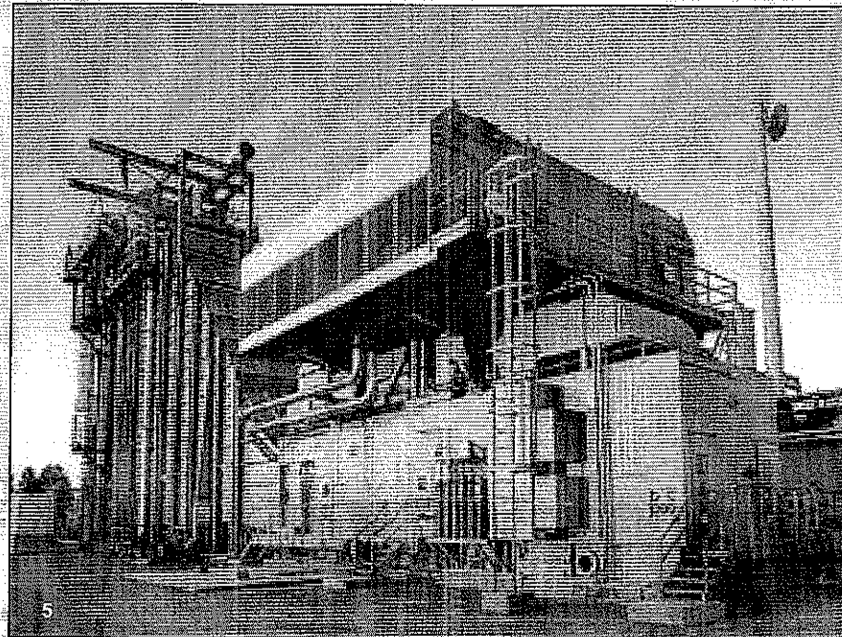
The selection of BRUSH generators for these prestigious installations is not surprising. Since positioning itself as a major supplier to the gas turbine industry in the 1960s, the company has achieved a leading position in the power generation market, as a supplier of both equipment and project engineering expertise.

5. One of two LM6000 gas turbine sets, equipped with BRUSH 2-pole generators, at a gas-fired, combined cycle power station in the USA. The plant is equipped with two LM6000s and provides 100 MW of power to the local grid.

6. Horsens Power Station, Denmark provides 35MW of electricity to the local grid. Power is generated by an LM2500 gas turbine and a 13MW steam turbine in combined cycle, both driving BRUSH generators.

7. A BRUSH 2-pole generator for a Frame 6B gas turbine package.

8. A 57MW gas-fired combined cycle power station owned and operated by the Viborg Municipality, Denmark, supplies base load power to regional electricity distributor Midkraft and process steam to a district heating scheme for 10,000 businesses and homes. The power station comprises a BRUSH generator driven by a 41MW gas turbine at one end and a 16MW steam turbine at the other.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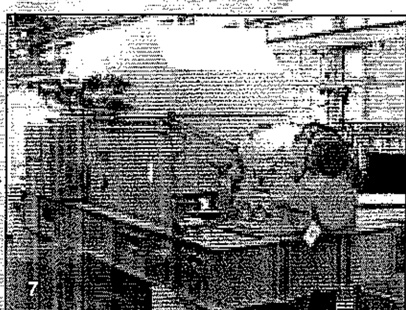
BRUSH was the principal subcontractor in the UK's first large scale commercial venture to produce electricity from landfill gas, at Packington Estate Enterprises Ltd (PEEL) near Birmingham.

The first stage of the project, a simple cycle installation based on a Centrax 501-KB5 gas turbine package, became operational in November 1987. BRUSH supplied the 4800kW generator, 11000 volt switchboard, 1000kVA step down transformer, generator control panel, 415 volt motor control centre, station battery, complete with charger unit, generator neutral earthing resistor and supervision of the electrical power system cabling. In 1992, with a continuing increase in waste gas, a decision was made to convert the installation to combined cycle, with an initial rating of 9000kW. To allow for the future installation of another gas turbine, an 8000kW Peter Brotherhood steam turbine, driving a BRUSH 4-pole generator, was selected.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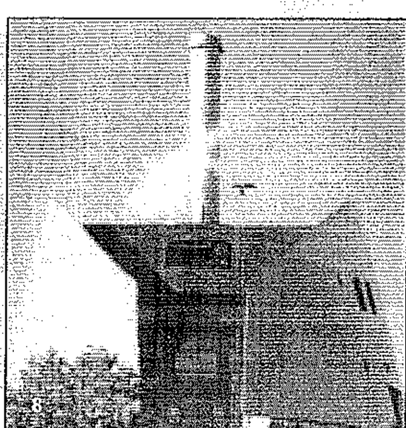
Generator Packages

BRUSH 2-pole and 4-pole turbogenerators are designed for both steam turbine and gas turbine drive, but the extent of the Company's experience is best demonstrated by reference to the gas turbine market. BRUSH has more experience of the use of gas turbines in power generation than any other generator manufacturer in the world. The continued success in the field of gas turbine generation can be attributed to BRUSH's ability to meet the demanding interface requirements of the turbine manufacturers, coupled with competitive prices and keen deliveries.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From the smallest of the DG range, rated at 10MVA, through to 1100MVA combined cooled units, BRUSH has a generator to match all current gas turbine and steam turbine applications.

Where required, BRUSH can provide the generator as a complete package, consisting of a self-supporting baseframe on which are mounted the generator, weatherproof acoustic enclosure, neutral earthing equipment and, where necessary, a load gearbox. The major benefit of a packaged generator is reduced installation and commissioning time at site.

In some drive configurations, either a 2-pole or a 4-pole generator could be used. The choice will depend on the application and possibly on local requirements; each type of generator has merits that may affect the decision. BRUSH is always ready to offer advice on the optimisation of generator selection.

APPENDIX 9
CATERPILLAR AND PRATT & WHITNEY GAS TURBINE RENTAL UNITS

From: Flinn, Dan [DFlinn@atlcat.ca]
Sent: Thursday, November 01, 2007 3:11 PM
To: King, Brian
Subject: Budget Prices fro the XQ5200

Attachments: Ideal Generator Data Sheet units 1-11.pdf; 2007 XQ5200 Drawings and data SoLoNox Dual Fuel.pdf; XQ2000.pdf; 3516-2000kw-600v.pdf

Brian, here's some budget prices for the turbine
All prices below are for one unit, not the full package. These are only budget price as well.

Turbine (XQ5200)

Following is a preliminary proposal designed for you to make a quick evaluation of the economics of utilizing Mobile Generation for your project.

Proposal Assumptions

1. 15 MW required @ 13.8kv, 60 hz.
2. Project start date: Spring 2008
3. Project duration is 3 months.
3. Fuel Diesel Fuel
4. Assumed elevation sea level.

Preliminary Proposal

Peterson Power Systems is a solutions provider that can provide any level of service you may require from supply of mobile generation equipment and balance of plant to engineering, setup, commissioning, maintenance and operation. Following is budgetary pricing.

A) Budgetary Summary Project Cost Build-up, US dollars 5.2MW Mobile Gas Turbines (SoLoNox): Model XQ5200.

Term	3 months
Rental Rate, 3 month minimum (Capacity Charge)	$105,000/month/unit
Fired Hour Charge	$42.00/hour/unit
Mobilization & Consumables	$16,000/unit.
Setup, Commissioning & test	$106,000/unit
Technician/Operator	$2,480/wk. (12 hrs per day on call remainder of day)
Decommissioning	$48,500/.unit

Included
1. Mobilization for shipment
2. Setup, commissioning and test of Gas Turbine 3. Solar commissioning Field Service Engineer 4. Rental of Mobile Generation Equipment 5. Maintenance 6. Tear down and decommissioning at end of rental term

Exclusions (excluded items quoted upon request) 1. Fuel storage tanks, fuel forwarding pumps, filter coalescer, daytank and fuel piping.
2. 15kV distribution cabling
3. Utility transformer 15kV to utility voltage 4. Coordination study 5. Import duties 6. Local Taxes of any kind 7. Property damage, and liability insurance (required) 8. Political Risk Insurance (if required) 9. Engineering of any of the above excluded items.
10. Regulatory approval (Operating Permits) 11. Emissions Source testing 12. Freight

(See attached file: 2007 XQ5200 Drawings and data SoLoNox Dual Fuel.pdf)(See attached file: Ideal Generator Data Sheet units 1-11.pdf)

Terms: REQUEST A FULL PROPOSAL FOR COMPLETE TERMS AND CONDITIONS. PRICES SHOWN ARE NET NO FURTHER DISCOUNTS APPLY.

The above proposal is provided for budgeting purposes only. ACTUAL PRICES MAY VARY BASED ON ACTUAL SITE CONDITIONS, RENTAL TERM, AND SCOPE OF SUPPLY.
All pricing is in Cdn Dollars.

Abbreviated Equipment Description

The Caterpillar Mobile Generation Units offered are all less than three to four years old and feature state of the art emissions controls. The Solar Taurus 60's (XQ5200) can operate on both natural gas and liquid fuels (liquid fuel quoted upon request) such as kerosene and diesel.

All of the Mobile Generation units are self-contained, sound attenuated, trailerized for easy delivery, and designed for quick connection and convenient servicing. All of these packages maintain a high power density. These full utility-grade Mobile Generation Units are capable of running stand-alone or infinitely parallel with the utility. On board are all of the necessary controls, and associated switchgear for parallel operation with a utility source. All of the mobile generation units are designed for minimal aesthetic and sound impact to the area. These sound attenuated enclosures have sound levels of 85 dbA at three feet (3').

Dan Flinn

Coordinator Rental/Used Generators

175 Akerley Blvd
PO Box 953
Dartmouth, NS B2Y 3Z6

Office 902 468 0581
Cell 902 499 6393
Fax 902 468 4222

CAT® Rental Power

XQ5200
Mobile Power Unit

Rental Power—When and Where You Need It

The XQ5200 is the answer to your need for short term generating capacity that is both economical and environmentally friendly. Designed as an on-site generating system where low emissions, fast setup and reliable operation are critical, the XQ5200 is based on the proven *Solar®* 5.2 MW *Taurus™* 60 gas turbine generator set a proven industry standard.

Easy to Install and Relocate

- Highway Transportable
- Modular Design for Quick Set-up and Connection
- No Concrete Foundation Required
- Compact Footprint to Minimize Space Requirements
- CSA certified

Environmentally Friendly

- Low Emissions, Utilizing SoLoNOx™ Combustion System
- No Visible Emissions
- Sound Attenuation Package for Quiet Operation
- Low Profile Design to Minimize Installed Height
- Easy to Permit

Flexible Solution

- Short and Long Term Rental Options Available
- 5.2 MW Output, 12.47 kV to 13.8 kV, 60 Hertz
- Fuel Flexibility, Natural Gas or Diesel

Complete Systems Solution

- Set-up and Commissioning
- Maintenance Included in Rental
- Operators Available
- Site Preparation Available
- Transformer Options

Operational Features

- Dispatchable to be On Line in Six Minutes (from cold start)
- Range of Control System Options for Remote Operation
- Utility Grade Switchgear with Programmable Protective Relay Module
- KVAR Control for Excellent Reactive Power Capability

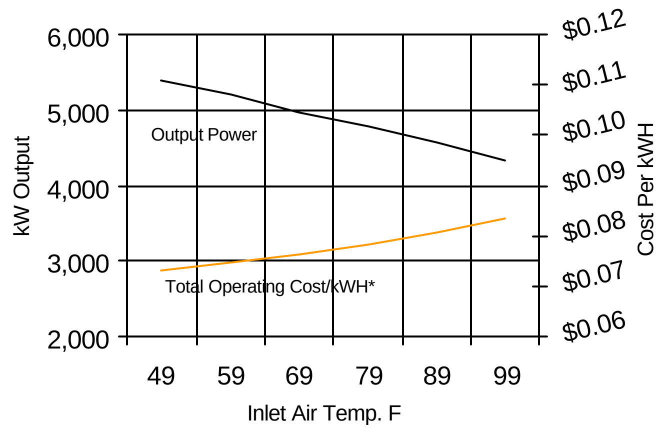
CAT® Rental Power

XQ5200
Mobile Power Unit

Nominal Generator Set Performance

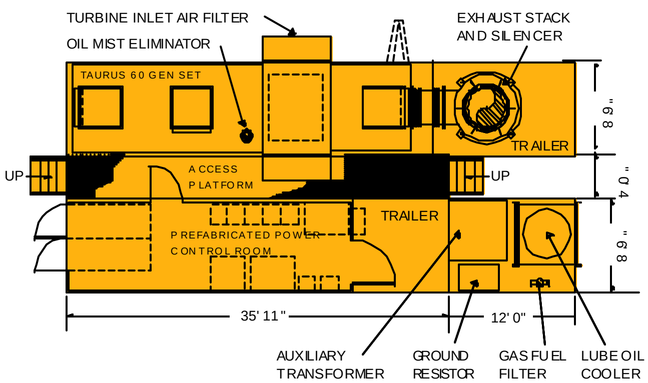
At the core of the XQ5200 is Solar's 5.2 MW *Taurus*™ 60 industrial gas turbine, with a population of more than 1,000 units in the field. The XQ5200 combines the features and benefits of the proven *Taurus*™ 60 industrial gas turbine with a mobile system that is easy to relocate and connect.

Output Power, kWe ISO: 15º C (59º F), sea level	5,200
Heat Rate, (Btu/kWe-hr)	11,263

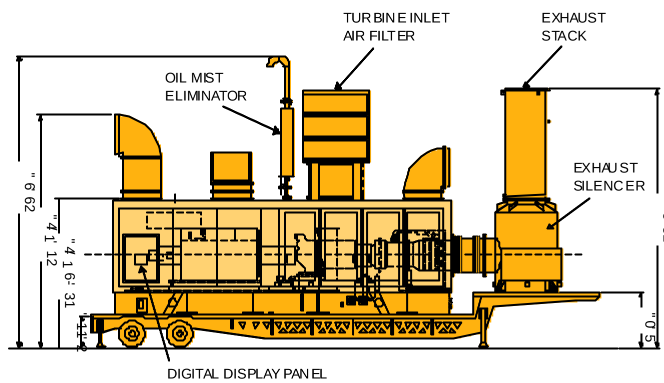


*Total operating cost includes fuel @ $3.50/MMBtu, Rental, Sales Tax and Maintenance

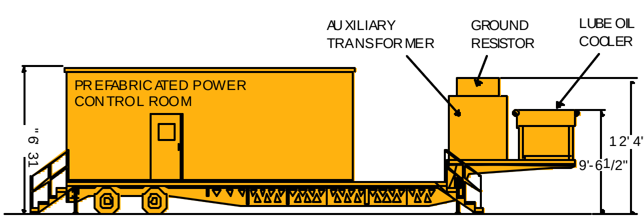
Typical Dimensions



Installation Plan View



Generator Set Module



Power Control Module

XQ5200 in Transit

Mobile Power– When and Where You Need It

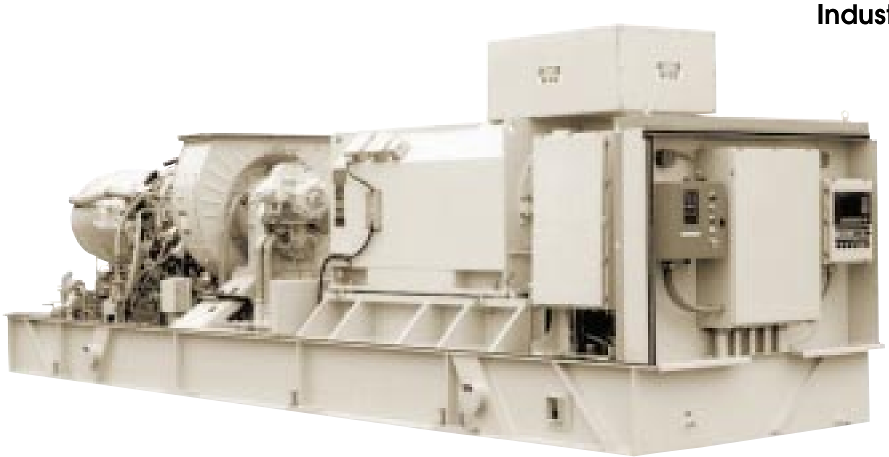
CATERPILLAR: WHERE THE WORLD TURNS FOR POWER

www.cat-rental.com

Solar® Turbines
A Caterpillar Company

TAURUS 60
Gas Turbine Generator Set

Industrial/Utility Grade



Features

- Industrial Gas Turbine Package
- Compact, Integrated Package Providing Ease of Installation
- Factory Tested
- Dry, Low Emission (*SoLoNOx*™) Combustion Available
- Onskid Microprocessor-Control with Auto Sync Capability
- Multiple Fuel Capability

Package Arrangement

Gas Turbine

- *Taurus*™ 60 Industrial, Single-Shaft
- Axial Compressor – 12 Stages
- Annular Combustion Chamber
  – 12 Fuel Injectors
- Coatings
  – Compressor: Inorganic Aluminum
  – Turbine and Nozzle Blades: Precious Metal Diffusion Aluminide
- Proximity Probe Vibration Transducers

Main Reduction Drive

- Epicyclic
  – 1800 or 1500 rpm
  – Acceleration Vibration Transducers

Generator

- Salient Pole, 3 Phase, 6 Wire, Wye Connected, Synchronous with Brushless Exciter
- Open Drip-Proof Construction
- Sleeve Bearings
- Velocity Vibration Transducers
- Solid-State Voltage Regulation with Permanent Magnet Generator
- NEMA Class F Insulation with F Rise
- Continuous Duty Rating

Package

- Steel Base Frame with Drip Pans
- Direct-Drive AC Start System
- Natural Gas Fuel System
- Control System
  – Microprocessor-Based PLC
  – Generator Control
  – Vibration and Temperature Monitoring
  – Auto Synchronizing
- Integrated Lube Oil System
  – Turbine-Driven Lube Pump
  – AC Pre/Post Lube Pump
  – Backup Lube Pump
  – Air/Oil Cooler
  – Integral Lube Oil Tank
  – Lube Oil Tank Heater
  – Lube Oil Filter
- Documentation
  – Drawings
  – Quality Control Data Book
  – Inspection and Test Plan
  – Test Reports
  – O&M Manuals
- Factory Testing of Turbine and Package

Optional Equipment/Services

- Generator Options:
  – WPII, TEWAC
  – Standby Duty Rating
  – Standard Voltages:
  3300, 6600, 11,000 50 Hz;
  4160, 6900, 12,470, 13,800 60 Hz
- Fuel Systems
  – Liquid
  – Dual (Gas/Liquid)
  – *SoLoNOx*, Dry, Low Emission
  – Alternate Fuels (such as naphtha, propane, low Btu)
- Lube Oil System
  – Water/Oil Lube Cooler
  – Electrostatic Demister
  – Duplex Lube Oil Filters
- Control System
  – Remote Display/Control Terminal
  – Heat Recovery Application Interface
  – Serial Link Supervisory Interface
  – KW Control
  – KVAR/Power Factor Control
  – Turbine Performance Map
  – Historical Displays
  – Printer/Logger
  – Predictive Emissions Monitoring
  – Field Programming Terminal
- Accessory Equipment
  – 24-VDC Battery/Charger System
  – Turbine Cleaning System: On-Crank and On-line
  – Package Lifting Kit
- Weatherproof Acoustic Enclosure
- Ancillary Equipment: Various Air Inlet and Exhaust Systems
  – Inlet and Exhaust Silencers
  – Self-Cleaning or Prefilter/Barrier Air Inlet Filter
  – Inlet Evaporative Cooler
  – Inlet Chiller Coils
  – Ancillary Support Frame

Solar® Turbines
A Caterpillar Company

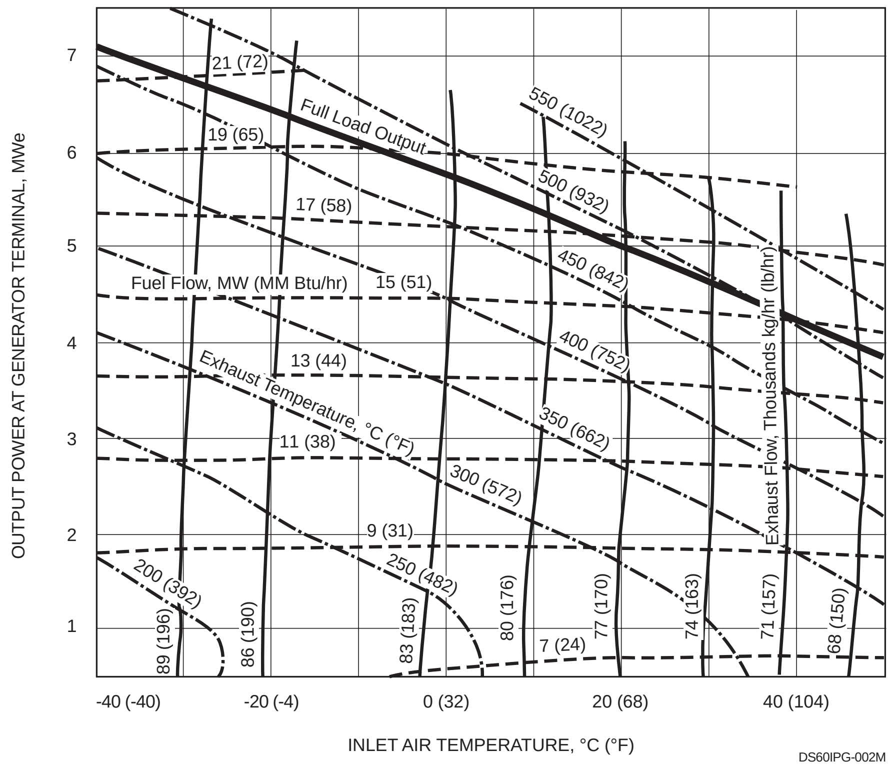
TAURUS 60
Gas Turbine Generator Set

Nominal Performance*

Output Power, kWe ISO: 15°C (59°F), sea level	5200
Heat Rate, kJ/kWe-hr (Btu/kWe-hr)	11 882 (11,263)
Exhaust Flow, kg/hr (lb/hr)	79 284 (174,798)
Exhaust Temperature, °C (°F)	486 (906)

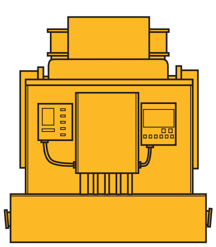
* *No inlet or exhaust losses*
Relative humidity 60%
Natural gas fuel with
LHV = 31.5 to 43.3 MJ/nm³
(800 to 1100 Btu/scf)

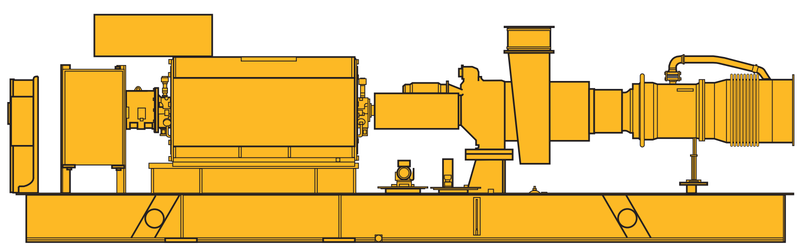
Available Performance

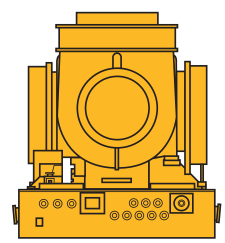


DS60IPG-002M

Typical Service Connections


Forward End


Left Side


Aft End

DS60IPG-003M

Forward End

- Turbine Control Box

Length: 9754 mm (32' 0")	
Width: 2438 mm (8' 0")	
Height: 2591 mm (8' 6")	
Approx. Weight: 29 300 kg (64,590 lb)	

Left Side

- Lube Oil: Drain, Vent, Cooler
- Generator Control Box, Power
- Generator Drip Pan Drain
- AC Power
  - Lube Tank Heater
  - Pre/Post Lube Pump
  - Backup Lube Pump

Right Side

- AC Power - Start Motor
- Generator Monitor Box

Aft End

- Fuel Inlet
- Turbine Cleaning
- Fuel Filter, Combustor and Exhaust Collector Drains
- Auxiliary Air (optional) for:
  - Liquid Fuel Atomizing
  - Self-Cleaning Filter
- AC Power
  - Liquid Fuel Pump (optional)
- Package Ground

Solar Turbines Incorporated

FOR MORE INFORMATION

ISO-9001
DNV
CERTIFICATED FIRM

DS60IPG/1198/5M

XQ5200 Data Sheet
SoLoNox, Dual Fuel
60 Hz.

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Table 1. XQ5200 Designation

Manufacturer	Solar Turbines Inc.
Turbine Model	Taurus 60, T7300S
Package Model Designation	XQ5200
Combustion System	So Lo Nox™
Fuel	Natural Gas & Diesel #2

Table 2. Dual Fuel Performance Data ISO*, XQ5200 Mobile Power Unit

	Natural Gas		*Natural Gas*		*Diesel #2*		*Diesel #2*	
	English		*Metric*		*English*		*Metric*	
Power Output	5,200	kWe	5,200	kWe	5,089	kWe	5,089	kWe
Heat Rate(LHV)	11,263	Btu/kWe-hr	11,900	kJ/kWe-hr	11,376	Btu/kWe-hr	12,002	kJ/kWe-hr
Fuel Flow (LHV)	58.6	mmBTU/hr	61.8	mmkJ/hr	57.9	mmBTU/hr	61.0	mmkJ/hr
Emissions** NOX	48	PPMvd	48	PPMvd	96	PPMvd	96	PPMvd
	11.16	LBM/HR	5.06	kg/hr	22.41	LBM/HR	10.16	kg/hr
CO	50	PPMvd	50	PPMvd	50	PPMvd	50	PPMvd
	7.1	LBM/HR	3.22	kg/hr	7.1	LBM/HR	3.22	kg/hr
Gen. Voltage @ 60 hz.	12.47 to 13.8 KV		12.47 to 13.8 KV		12.47 to 13.8 KV		12.47 to 13.8 KV	
Voltage Steady State	0.5%		0.5%		0.5%		0.5%	
Short Circuit	300% for 10 sec.		300% for 10 sec.		300% for 10 sec.		300% for 10 sec.	

* ISO = Sea Level, 60% Relative Humidity, No inlet or exhaust losses.
** Emissions valid if Load factor is > 50% on natural gas and > 80% on diesel fuel.

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Table 3. Natural Gas Site Performance data, METRIC

TAURUS 60-T7300S — Heat Rate Data Given is Lower Heating Value
GSC STANDARD
Std. Natural Gas Fuel

Rel Humid, %	60						
SITE ELEVATION:	0	metre					
BAROMETRIC PRESSURE:	760.0	mmHg					
INLET DUCT LOSS:	76.2	mmH2O					
EXHAUST DUCT LOSS:	76.2	mmH2O					
Nominal Data Single Unit							
AMBIENT AIR TEMPERATURE (T1):	-7	4	15	27	38	48	°C
PART POWER (kWe), % LOAD, or 0 for MAX:	100%	100%	100%	100%	100%	100%	kWe
Nominal OUTPUT POWER: (@terminals)	5,869	5,488	5,095	4,661	4,214	3,827	kWe
FUEL FLOW (LHV):	67,563	64,765	61,323	57,681	54,254	51,485	MJ/hr
Nominal HEAT RATE: (@terminals)	11,511	11,802	12,037	12,375	12,875	13,452	kJ/kWe-hr
EXHAUST GAS TEMPERATURE (T7):	484	485	488	495	504	516	°C
EXHAUST GAS FLOW:	83,982	81,689	78,819	74,939	70,718	66,866	kg/hr
Nominal THERMAL EFFICIENCY: (@terminals)	31.28	30.51	29.92	29.10	27.97	26.77	%
PCD PRESSURE:	1,202	1,159	1,110	1,061	1,002	946	kPaG
EXHAUST HEAT (from T7 to T9):	31,886	31,167	30,277	29,369	28,405	27,712	MJ/hr

Table 4. Natural Gas Site Performance data, ENGLISH

TAURUS 60-T7300S — Heat Rate Data Given is Lower Heating Value
GSC STANDARD
Std. Natural Gas Fuel

Rel Humid, %	60						
SITE ELEVATION:	0	Feet					
BAROMETRIC PRESSURE:	29.9	"Hg					
INLET DUCT LOSS:	3	"H2O					
EXHAUST DUCT LOSS:	3	"H2O					
Nominal Data Single Unit							
AMBIENT AIR TEMPERATURE (T1):	20	40	59	80	100	118	°F
PART POWER (kWe), % LOAD, or 0 for MAX:	100%	100%	100%	100%	100%	100%	kWe
Nominal OUTPUT POWER: (@terminals)	5,869	5,488	5,095	4,661	4,214	3,827	kWe
FUEL FLOW (LHV):	64	61	58	55	51	49	mmBTU/hr
Nominal HEAT RATE: (@terminals)	10,911	11,186	11,409	11,729	12,203	12,750	BTU/kWe-hr
EXHAUST GAS TEMPERATURE (T7):	903	906	910	923	939	960	°F
EXHAUST GAS FLOW:	185,149	180,094	173,767	165,212	155,908	147,414	lb/hr
Nominal THERMAL EFFICIENCY: (@terminals)	31.28	30.51	29.92	29.10	27.97	26.77	%
PCD PRESSURE:	174	168	161	154	145	137	PsiG
EXHAUST HEAT (from T7 to T9):	30	30	29	28	27	26	mmBTU/hr

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Table 5. Diesel #2 Site Performance data, METRIC

Diesel 2-D Fuel							
RELATIVE HUMIDITY	76	%					
SITE ELEVATION:	0	metre					
BAROMETRIC PRESSURE:	760.0	mmHg					
INLET DUCT LOSS:	76.20	mmH2O					
EXHAUST DUCT LOSS:	76.20	mmH2O					
Distillate Fuel Formulas, (Diesel #2)							
Heat Value KJ/kg	41,925.00						
kg/litre	0.8543						
Fuel Temp.	29 C						
AMBIENT AIR TEMPERATURE (T1):	-6.7	4.4	15.0	26.7	37.8	47.8	°C
PART POWER (kWe), % LOAD, or 0 for MAX:	100%	100%	100%	100%	100%	100%	kWe
Nominal OUTPUT POWER: (@terminals)	5,750	5,377	4,990	4,565	4,118	3,738	kWe
Nominal HEAT RATE: (@terminals)	11,625	11,907	12,152	12,507	13,029	13,634	kJ/kWe-hr
EXHAUST GAS TEMPERATURE (T7):	484	487	489	496	505	518	°C
EXHAUST GAS FLOW:	84,182	81,858	78,985	75,067	70,838	66,999	kg/hr
Nominal THERMAL EFFICIENCY: (@terminals)	30.98	30.24	29.63	28.79	27.64	26.41	%
PCD PRESSURE:	1,197	1,152	1,109	1,057	999	945	kPaG
EXHAUST HEAT (from T7 to T9):	29,429	28,894	28,013	27,264	26,404	25,874	MJ/hr
Liters per Hour	1,866	1,788	1,693	1,594	1,498	1,423	Nominal
Liters per kW-HR	0.325	0.332	0.339	0.349	0.364	0.381	Nominal
Liters per MW-HR	325	332	339	349	364	381	Nominal

Table 6. Diesel #2 Site Performance data, ENGLISH

Diesel 2-D Fuel							
RELATIVE HUMIDITY	60	%					
SITE ELEVATION:	0	feet					
BAROMETRIC PRESSURE:	29.9	"Hg					
INLET DUCT LOSS:	3.00	"H2O					
EXHAUST DUCT LOSS:	3.00	"H2O					
Distillate Fuel Formulas, (Diesel #2)							
Heat Value, BTU/LB in LHV	18,390						
Lbs./Gal.	7.001						
Fuel Temp.	85 deg. F						
AMBIENT AIR TEMPERATURE (T1):	20	40	59	80	100	118	°F
PART POWER (kWe), % LOAD, or 0 for MAX:	100%	100%	100%	100%	100%	100%	kWe
Nominal OUTPUT POWER: (@terminals)	5,750	5,377	4,990	4,565	4,118	3,738	kWe
Nominal HEAT RATE: (@terminals)	11,018	11,286	11,518	11,854	12,350	12,923	BTU/kWe-hr
EXHAUST GAS TEMPERATURE (T7):	903	909	911	926	941	964	°F
EXHAUST GAS FLOW:	185,589	180,465	174,132	165,494	156,170	147,708	lb/hr
Nominal THERMAL EFFICIENCY: (@terminals)	30.98	30.24	29.63	28.79	27.64	26.41	%
PCD PRESSURE:	174	167	161	153	145	137	PsiG
EXHAUST HEAT (from T7 to T9):	28	27	27	26	25	25	mmBTU/hr
Gallons per Hour	492.1	471	446	420	395	375	Nominal
Gallons per kW-HR	0.086	0.088	0.089	0.092	0.096	0.100	Nominal
Gallons per MW-HR	85.6	87.7	89.5	92.1	95.9	100.4	Nominal

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Table 7. Dimensional Data & Weights, Installed XQ5200 Mobile Power Unit

	English	*Metric*
Length	48 ft.	14.6 meters
Width	21 ft.	6.4 meters
Height	26.6 ft.	8.1 meters
Installed Weights		
Turbine Section	118,000 lbs	54 M tons
PCR Trailer	55,000 lbs.	25 M tons

Table 7A. Dimensional Data and Weights, Ocean Shipping.

Item #.	*Lbs. (Metric tons)*	*Dimensions L X W X H English (Meters)*	*Description*
1	118,000 (53.6)	48'3" X 9' X 14'2" (14.7 x 2.75 x 4.32)	Turbine Enclosure w/ Integral Trailer. Air ride, 3 Axle, Mfg. by Solar Turbines Inc..
1A	6,900 (3.2)	14'1" X 8'6" X 3'6" (4.3 x 2.6 x 1.1)	Two Axle Air Ride Booster. Connects to Item 1 for highway transport but is removed for ocean transit and when assembled for operation.
2	55,000 (25)	46' X 8' 6" X 13'9.5" (14 X 2.6 X 4.2)	Power Control Room w/ Integral Trailer. Air ride, 2 Axle. Manufactured by Solar Turbines Inc.
3	35,000 (15.9)	40' X 8' X 8' 6" (12.2 x 2.5 x 2.6)	40 ft. shipping container packed with turbine auxiliary components.
3A	8,500 (3.9)	41' x 8' x 4' (12.5 x 2.5 x 1.2)	Chassis for Item 3. Optional 40 ft. fixed chassis for container.
4	35,000 (15.9)	40' X 8' X 8' 6" (12.2 x 2.5 x 2.6)	40 ft. shipping container packed with special tooling and spare parts
4A	8,500 (3.9)	41' x 8' x 4' (12.5 x 2.5 x 1.2)	Chassis for Item 4. Optional 40 ft. fixed chassis for container.

Table 7B. Dimensional Data and Weights, Highway Shipping.

Item #.	*Lbs. (Metric tons)*	*Dimensions L X W X H English (Meters)*	*Description*
1 & 1A	124,900 (56.7)	62'1" x 9' X 14"2" (19 x 2.75 x 4.32)	Turbine Enclosure w/ Integral Trailer & Booster. Item 1 & 1A configured for highway transport by Truck. 5 axles.
2	55,000 (25)	46' X 8' 6" X 13'9.5" (14 X 2.6 X 4.2)	Power Control Room w/ Integral Trailer. Air ride, 2 Axle. Manufactured by Solar Turbines Inc.
3 & 3A	43,500 (15.9)	41' X 8' X 12' 6" (12.5 x 2.5 x 3.8)	40 ft. container w/ Chassis packed with turbine auxiliary components.
4 & 4A	43,500 (15.9)	41' X 8' X 12' 6" (12.5 x 2.5 x 3.8)	40 ft. container w/ Chassis packed with special tooling & spares.

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Table 8. Installation Requirements XQ5200 Mobile Power Unit

	English	*Metric*
Natural Gas		
Gas Pres.	250 PSIG	1,723 KPAG
Max. Gas Demand	1,400 SCFM	39.6 M^3/MIN.
Diesel #2		
Fuel Pres.	25 – 50 PSIG	172 – 345 KPAG
Fuel Flow	8 GPM	30.3 L/Min
Foundation		
Gravel Compacted to	2,500 lbs./ft.2	120 kPA
Fuel Quality		
Clean dry fuel Per Solar Spec. ES 9-98.		

Table 9. Infrastructure Requirements, XQ5200 Mobile Power Unit

Connections

Black Start, if needed (480V 60 hz., 200kW)

Telephone Line, ether net, broadband connection for Remote Communication & Control

Set Up & Commissioning

Three – Five days

Small crane to lift components on roof, & fork Lift.

Table 10. Solar Turbotronic Controller, XQ5200 Mobile Power Unit

Allen Bradley, PLC-5

Provides sequencing to the package's operating systems during starting, running & shutdown, and provides package monitoring and protection during all phases of operation. Key features include…

- *Local operator interface and monitoring.
- *Interface and monitoring in power control trailer
- *Remote interface and monitoring.
- *Operational summary displays of alarms, shutdowns, temperatures, pressures, vibration, engine performance, generator kW, voltage, p.f., hz., amps, current.
- *Relay backup in event of PLC failure
- *Flexibility to change logic or add features

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Table 11. Switchgear, XQ5200 Mobile Power Unit

Operating Features, ***(One Line Available upon request)***
Parallel operation with the utility.
Island operation single or multiple units.
Protective Relays, (See Table 8)
Vacuum Circuit Breakers, 1,200A, 500MVA @ 15 KV
Breaker #1 customer load connection
Breaker #2 feeds Aux. Transformer & MCC to power turbine Accessories.
C.T.'s, Draw Out P.T.'s.
Lightning Arrestors, & Surge Capacitor

Table 12. Grounding, XQ5200 Mobile Power Unit

Option 1	Low Resistance grounding
Option 2	Ungrounded generator

Table 13. Protective Relays, XQ5200 Mobile Power Unit

Beckwith M-3425	***Designation***
Impedance	21
Undervoltage	27
RPR	32
Loss of Field Protection	40
Negative Phase Sequence	46
PT Blown Fuse	60FL
Phase overcurrent	51V
Inadvertent energization	50/27
Ground Overcurrent	50N, 51N
Overvoltage	59
Bus Ground Fault Detection	59N
Over/Under Frequency	81
Phase Differential overcurrent	87
Ground differential Settings Programmable for resistance grounding or ungrounded operation.	87GD
Basler BE-1, Overcurrent	50/51B

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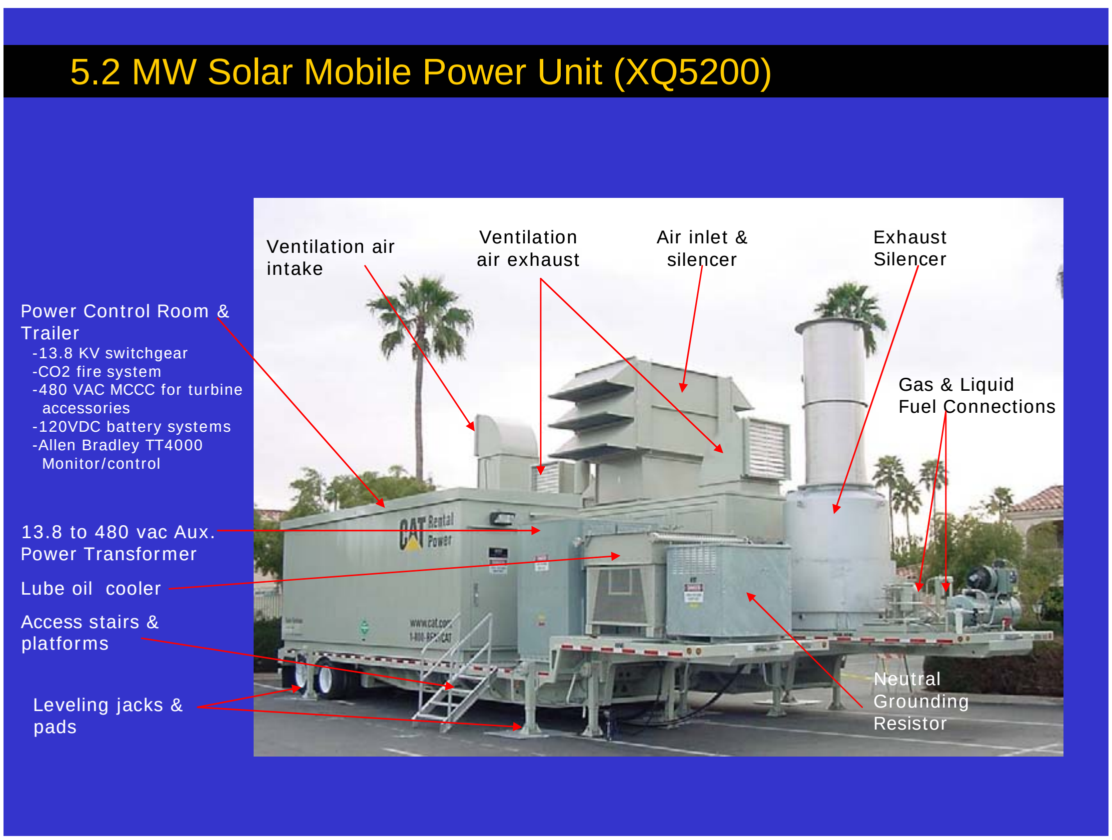
Table 14. XQ5200 Rental Power Benefits

Flexible Rental Solution	*Easy to Install & Relocate*
Short & Long Term Rental Options Rental/Purchase Options 50 or 60 hz. Units available	Highway transportable 3 to 5 day setup No concrete foundation required
Environmentally Friendly	***Complete Systems Solution***
Low Emissions, 25 ppmv Nox Quiet Operation, 87 dba @ 3 ft. (1M) No Visible Emissions Low Profile Design Easy to Permit	Set-up & Commissioning Maintenance Included Operators available Site Preparation (if needed) Transformers (if needed)
Worldwide Support	***Operational Features***
Caterpillar's Worldwide Rental Network Solar Turbines Worldwide Service Network	On line in six minutes Range of Control System Options KVAR Control & KW Control

Table 15. XQ5200 Photo Overview



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TAURUS 60 MOBILE POWER UNIT

Turbine Generator Set Module (Basic Package):

The Taurus 60 Industrial Power Generator (PG) is a compact, rugged gas turbine generator set that has been designed to meet the requirements for industrial power generation applications. The gas turbine engine, gearbox, generator, control system, fuel system, lubrication system, start system, and ancillary equipment are included in the package.

Features included in this proposal are:

Base. The base provides structural support for the Taurus 60 gas turbine engine, gear box, generator, enclosure, and all operating systems. The base is manufactured by Solar using structural steel with welds per AWS D1.1.

Drip pans are welded beneath the package frame to collect potential liquid spills. The drip pans also provide a tight seal for containment of fire suppression agent.

Piping. All tubing and piping up to 4 inches nominal diameter is stainless steel. Package piping is designed and fabricated to ANSI B31.3.

Tube Fittings. All tube connections use compression fittings. Tube fittings are zinc plated carbon steel.

Note: Throughout the proposal, all references to the package orientation (left, right, clockwise, counterclockwise, etc.) are based on standing at the "aft" (e.g. turbine exhaust) end of the package looking forward.

Electrical System. The Taurus 60 IPG generator set is designed to comply with the requirements of the National Electrical Code and is intended to be installed in a non-hazardous location per NFPA 37.

Unless otherwise noted package motors and heaters are rated for 480 Vac, 60 Hertz, 3 phase. Unless otherwise noted single phase loads are rated for 220 Vac, 60 Hertz.

GAS TURBINE ENGINE

The Taurus 60 gas turbine engine is a single shaft axial flow engine. The output gearbox, including accessory drive pads, is a separate, close-coupled unit located at the inlet end of the turbine.

The engine assembly consists of:

- Gear unit with accessory drive pads
- Air inlet collector with flexible flange connection
- Axially split case in the vertical plane, twelve-stage axial flow compressor with variable geometry control on inlet guide vanes and first three rows of stators
- Annular combustor with 12 fuel injectors
- Three-stage turbine assembly
- Turbine exhaust collector

The components of the Taurus 60 engine are maintained in accurate alignment by mating flanges with pilot surfaces and are bolted together to form a rigid assembly. The speed reducing gear box is driven by the compressor rotor shaft. Accessory pads drive the main lube oil pump and other accessories, depending on the application, and supports the starter motor.

The gas turbine output shaft is mechanically coupled to both the compressor and turbine sections of the engine to form a "solid" or "single" shaft configuration. This feature enhances speed stability and response under constant and varying load conditions -- a highly desirable feature in generator applications requiring precise frequency control.

SPEED REDUCING GEARBOX

The speed-reducing gearbox is an epicyclic star-gear industrial design manufactured by Solar specifically for the Taurus 60 PG generator. The gearbox mounts directly on the Taurus 60 gas turbine to reduce engine speed to 1800 rpm (60 Hz).

GENERATOR

- Salient Pole, 3 Phase Generator with the follow characteristics:

Rating. The generator is rated per NEMA standards so that the generator will not limit turbine performance over the range of site ambient temperatures. Generator standard features include:

- Sleeve Bearings with pressure fed sumps
- Six-lead WYE connection
- Terminal box
- Form wound stator windings
- Damper windings
- Rotor balance to 125% rated speed
- Permanent magnet pilot exciter
- Anti-condensation space heaters

- 300% short circuit capability for 10 seconds
- Overload capacity per NEMA:
  - 150% rated current for 1 minute
    - 110% for 2 hours

Voltage Regulator Characteristics

- Solid state
- Single-phase sensing
- ±10% voltage adjustment range
- 0.5% steady state voltage regulation
- Reactive load sharing to within 5% nameplate rating
- Crosscurrent compensation capability

Wave Form Characteristics

- Deviation Factor [maximum] 6%
- Harmonic Content [maximum] 3%
- Telephone Interference Factor50
- Balanced Residual 75

Voltage Drift. The change in voltage will not exceed 1.0% over a 30 minute period when the generator is operating at rated voltage and 0.8 to 1.0 power factor and with a constant load between no load and full rated load.

Generator Construction. An open drip proof generator per NEMA standards is provided.

Generator Voltage. The generator output is 12,470 – 13,800 Volt, 3 phase, 60 Hz. Insulation conforms to NEMA class F with class F (105^{0}C) temperature rise.

FUEL SYSTEM

The fuel system, in conjunction with the electrical control system, includes all necessary components to control the fuel pressure, to schedule fuel flow during start-up, and to modulate fuel flow during operation.

Dual Natural Gas or Liquid Fuel. A system capable of operating on natural gas or liquid fuel is provided with all components necessary to maintain turbine speed to provide a constant generator output frequency and/or load depending on the generator set mode of operation. Solar's Specification ES 9-98 contains specific requirements for fuel and combustion air. The dual fuel system, which operates on either natural gas or liquid fuel, includes the controls for automatic changeover from one type of fuel to the other during operation.

Natural Gas Fuel. The natural gas fuel system includes:

- Primary fuel shutoff valve
- Pilot-operated secondary fuel shutoff valve
- Electronic actuated fuel control valve
- 10-micron pilot gas filter
- Compressor discharge pressure gauge
- 12 fuel injector assemblies
- Valve check pressure switch
- Low gas fuel pressure alarm and transfer software for use with discrete input signal from user fuel source
- High gas fuel pressure shutdown switch
- Gas strainer

System Requirements

- Requires a constant supply of gas at a maximum flow demand rate of 32.2 nm^3/min (1200 scfm) at 1725 kPa gauge (250 psig) minimum and 2070 kPa gauge (300 psig) maximum pressure. Gas fuel pressure is used to operate the fuel system pilot valve.
- The gas fuel should be free of sulfur, contaminants, entrained water, and liquid hydrocarbons
- Gas fuel must conform to Solar's Specification ES 9-98

Liquid Fuel System. The Liquid Fuel System includes:

- 7.5-hp VFD ac motor-driven main fuel pump
- 12 fuel injector assemblies
- Duplex low pressure fuel filters with replaceable 10-micron filter elements
- Low pressure fuel filter changeover valve
- Simplex 25-micron high pressure fuel filter
- Low fuel pressure transmitter
- Liquid fuel solenoid-operated valves -- main fuel shutoff, purge, bypass, and torch shutoff valves
- Drain to off skid liquid fuel purge tank (supplied by others)

System Requirements

- Requires a constant supply of liquid fuel at a maximum flow demand rate of 30.3 L/min (8.0 gpm).
- Fuel must conform to Solar's Specification ES 9-98. Typical acceptable fuels include:
  - Grades 1 and 2 fuel oil
  - Grades 1 and 2 diesel
  - Kerosene (JP-8, JP-5, or commercial grade)

NEC, NON-HAZARDOUS ELECTRICAL CLASSIFCATION

- CSA and CSA_{NRTL} Certification

DIRECT START SYSTEM

A direct drive AC motor is provided to start the gas turbine engine. A variable frequency drive [VFD] motor controller is included. The control system provides all required sequencing to quickly and reliably start the turbine.

LUBE OIL SYSTEM

A complete lube oil system suitable for operation with lube oil conforming to Solar's Specification ES 9-224 is included. The lube oil system provides oil to the bearings in the Taurus 60 gas turbine engine, gear box and generator. Instrumentation, flow control and on frame piping are included.

Main Lube Oil Pump. An engine driven lube oil pump is provided with suction strainer.

Pre/Post Lube Pump. A 2 hp (1.5 kW) AC motor driven pump is provided to supply lube oil flow prior to start up and after shutdown of the gas turbine.

Post Lube Backup Pump. A 1.5 hp (1.1 kW) DC motor driven pump is provided to supply post operation lube oil flow in the event of power failure. Power is provided by a 120 Vdc battery system.

Drain Line Sight Glasses. Sight glasses are provided on the drain lines from all gas turbine, generator and gear box bearings. Note that some of the gas turbine bearings have a common drain line.

Lube Oil Tank. A carbon steel lube oil tank is provided integral with the package frame. Lube oil level indicator, fill connection with inlet strainer and drain connections are included.

Lube Oil Tank Heater. A thermostatically controlled 4.5 kW lube oil tank heater is provided.

Lube Oil Cooler. An air/oil lube oil cooler is provided. A 5-hp (3.7 kW) AC motor drives the fan. The lube oil cooler is mounted on the Power Control Room trailer. Quick Disconnect-Interconnect hoses between the Power Control Room trailer and Turbine trailer is included.

Lube Oil Type. Lube oil is included. The lube oil complies with Solar specification ES 9-224. This project will be configured for petroleum base oil, viscosity grade C32.

Lube Oil Filter. A simplex 5 micron oil filter is provided with drain, fill and vent valves, differential pressure alarm transmitter.

PLC BASED CONTROL SYSTEM (with 120 VDC Battery Supply):

Solar's Turbotronic™ control system is provided. The Turbotronic control system is a highly integrated programmable logic controller [PLC] based control system. The control system is installed on the package frame to minimize interconnect wiring. The control system includes a microprocessor, remote communications modules, chassis based and flex input/output modules, line synchronization module, power supplies and a hardware backup shutdown system. The control system provides for control of all phases of package operation to include start and shutdown sequencing, normal operation, and malfunction shutdown.

Local Display. The control system is installed on the package frame in weather proof enclosures. A digital control panel [DCP] with all necessary switches and indicators is provided. In addition to display of "first out" malfunctions, the DCP can display:

System summary/normal running data
System status
Digital display of engine and generator parameters
Alarms and Shutdowns

Audible Alarm. An audible alarm horn is provided to sound whenever the unit has an alarm or shutdown condition. A horn silence push button is mounted on the face of the control panel.

Vibration Monitoring. Vibration monitoring is provided to include three proximity probes, one per bearing, on the engine. One accelerometer is provided with the gearbox. Two velocity transducers, one per bearing are provided with the generator. Preset warning indications and malfunction shutdown initiations are provided.

Temperature Monitoring. Temperature monitoring is provided to include the engine thrust bearing, lube oil header, generator bearings and stator windings. Preset warning indications and malfunction shutdown initiations are provided. Ambient, lube oil tank and enclosure temperatures are also monitored.

GENERATOR CONTROL AND MONITORING SYSTEM

Integrated monitoring and control of the generator is provided using a specially designed module in the PLC to receive input data from potential and current transformers. The system calculates real and reactive power, power factor and the variables required for synchronization.

Automatic Synchronizing. An automatic synchronizer is provided with the control system to automatically synchronize the unit to the bus through push-button control on the digital control panel [DCP] or by receipt of an appropriate remote signal. A synch check relay is provided as an additional permissive and for backup protection.

Motorized Voltage Adjust. Raise/lower voltage push button control is provided on the digital control panel to control a motorized potentiometer for voltage control. An additional raise/lower switch, supplied by others, may be used to control voltage from a remote location.

KW Controller. A kW controller is provided to control the real load (kW) on the generator set while operating in parallel with a utility or other large source. The kW controller monitors the load carried by the generator set and adjusts the turbine's fuel flow to maintain a constant load as plant load changes. Protection against excessive kW load while in parallel with a large source is provided by the control system "T5" temperature limiter. The kW control system provides additional operational flexibility by allowing unit kW load level to be set at any desired level within the capacity if the unit. The kilowatt load level select switch and level adjustment is located on the digital control panel.

KVAR/Power Factor Controller. A kVAR/power factor controller is provided to maintain a constant reactive load (kVAR) output or constant power factor (pf) on the generator set while the unit is operating in parallel with a utility or other large source. The controller applies a signal directly to the voltage regulator adjust circuit to maintain a constant reactive load or power factor with changes in the infinite bus voltage level. The system incorporates a set point adjust rheostat to set the desired kVAR or pf, a selector switch to choose kVAR or pf control mode, and a switch to turn the controller on and off.

Supervisory Interface. An RS 232C/422 interface module is provided to give the user's supervisory computer access, such as SCADA, to the Turbotronic control system data. Limited control capability is provided to allow the supervisory computer to start and stop the unit, reset alarms, and raise/lower speed and load set points.

The communications protocol is Allen Bradley's DF1.

The interface module may be located up to 10,000 feet (3,048 meters) from the turbine control system and located up to 50 feet (15 meters) from the supervisory computer for the RS 232C module or 4,000 feet (1,219 meters) for the RS 422 module.

Engine Performance Map. A display of real time engine performance is provided on the remote VDT. Performance data is corrected to standard conditions. The performance map is provided for reference and to monitor trends.

Historical Displays. The following maintenance and diagnostic programs are provided to assist in routine monitoring of gas turbine condition as well as to assist in making informed predictions of the future health of the unit.

Run Time Display - This feature provides a four channel strip chart format display on the VDT. It provides simultaneous, real time display of multiple operator selected parameters.

Elapsed Time Display - This feature is used for plotting and determining trends in the unit's performance. Selected parameters are stored on disk regardless of whether the unit is running. Data is saved at pre-determined intervals and can be retrieved for analysis.

Predictive Trend Monitoring - This feature analyzes historical data and approximates future analog trends. Deteriorating trends will result in a display that has the trend line intersecting a predetermined alarm or shutdown level at an indicated future time.

Remote VDT and Control. A remote video display terminal [VDT] is also provided. The VDT displays an expanded set of operating information including all of the data available on the panel and provides the capability to start and stop the unit, initiate automatic synchronization and open circuit breaker. Data which may be displayed on the remote VDT includes:

Turbine Engine Parameters:

T5 temperature	Fuel actuator current
Lube oil temperature	Fuel actuator minimum setting
Lube oil tank temperature	Control mode
Lube oil pressure	Operation mode
Start sequence status	Status lights

Generator Parameters

KW load	Generator Voltage, each phase
KVA/KVAR	Average Voltage

Power factor	Generator current, each phase
Frequency	Average current

Commands which may be sent to the PLC include:

Start
Stop
Initiate synchronization
Open circuit breaker
Raise or lower kW control setpoint

The remote VDT consists of an industrial type personal computer mounted in the Power Control Room trailer.

Remote Dial Up Monitoring and Control. Included in the Remote Video Display is the ability to dial the unit from a remote location, display monitoring screens, and execute control actions to start and stop the unit, reset alarms, and raise/lower speed and load set points. The VDT is connected to the generator set PLC via Controlnet. The Power Control Room is equipped with a telephone line connection.

TURBINE COMPRESSOR CLEANING

An On-Crank and On-Line engine cleaning system is provided. The systems are independent of each other and include separate distribution manifolds and injectors in the engine air inlet collector and associated on-skid plumbing to deliver water and/or approved cleaning solution to the manifold. Water and cleaning solutions used for engine cleaning must comply with Solar Specification ES 9-62. Requires Optional Water Wash Supply Cart (one per site)

WEATHERPROOF ACOUSTIC ENCLOSURE

Ventilation Silencers and Fans, Lights, Fire Detection and Gas Monitoring System with Auto Shutdown and Fuel Supply Shutoff, High Temperature Detection and Alarm, CO2 Fire Suppression System.

Language. Package labels and screen displays will be in English.

COMBUSTION INLET SYSTEM

- High Efficiency Barrier Filter and Silencer mounted on top of Generator Set enclosure.

EXHAUST SYSTEM

Included is a trailer mounted exhaust silencer with a 25-foot Stainless Steel Rains Stack.

The stack is equipped with flanged emission ports for emission sampling.

FACTORY TESTING (Performed on new units @ time of Manufacture)

Gas Turbine Engine Testing. The gas turbine engine is tested in accordance with Solar specifications to confirm that power, heat rate, and vibration levels meet Solar standards.

Generator Testing. The generator is tested in accordance with IEEE Standard Specifications and Solar's specifications at the manufacturer's plant. These tests satisfy requirements for NEMA and Solar. Supplier testing is under periodic Solar quality control review to ensure compliance with required specifications.

Radiography Inspection. Radiographic inspection is performed in accordance with ASME Section V. Five (5) percent of each welder's work (circumferential butt welds only) is inspected by radiographic examination in accordance with ANSI/ASME B31.3. The specific manifolds on a given unit may or may not be part of the 5% of each welder's work which is examined.

Quality Assurance. All testing operations are conducted under the direct control of Solar's Quality Assurance Activity. This Activity ensures compliance with the specified test limits and procedures.

In addition to final in-plant testing of the finished generator set, Quality Control engineers maintain surveillance over the manufacture of all purchased parts and subassemblies, and are responsible for functional testing of incoming components. The same rigid standards applied to parts manufactured by Solar are applied to all parts from suppliers.

TURBINE TRAILER (Model TK95LCS)

- Tri-Axle Transport Trailer with Two Axle Pivoting Booster
- Trailer Length 48' + 14'1" Booster (removable at site)
- Width 8'6", 9'0" across trailer axles
- 133" Swing Clearance
- 49" 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 Leveling/Stabilization at Site
- Overall transport height: 14'2"
- Approximate transport weight: 118,000 lbs (without tractor)

POWER CONTROL MODULE (consists of the following):

- Power Control Room (PCR) mounted on Two Axle Transport Trailer.
- Power Control Room HVAC system
- Generator Main Circuit Breaker. Single interface point to power grid
- Auxiliary Transformer Feeder Circuit Breaker
- Bus PTs, Feeder CTs, Metering CTs and PTs
- Beckwith M-3425 Protective Relay Module with the following relays:

  - Impedance (21)
  - Reverse Power Protection (32)
  - Loss of Field Protection (40)
  - Negative Phase Sequence Protection (46)
  - PT Blown Fuse Protection (60)
  - Time Overcurrent Protection (50/51 V)
  - Neutral Overcurrent Protection (51 N) – utilized in grounded site design
  - Bus Ground Fault Detection (59N) – utilized in ungrounded site design
  - Generator Differential Fault Protection (87 G)
  - One High Speed Tripping Relay (86) for Circuit Breaker Trip, Lockout, and Turbine Shutdown Settings, Programming, and Testing are included.

- Lightning Arrestor and Surge Capacitor
- Motor Control Center. Serves Turbine Generator Auxiliary Loads
- 120VDC Turbine Generator Battery System with Charger
- Dedicated 120VDC Switchgear Battery System with Charger
- Start Motor Variable Frequency Drive (VFD)
- DC Backup Lube Oil Pump Contactor
- Interior Lighting. Photocell Controlled Exterior Lighting at Access Doors
- Emergency Eyewash Station

Ancillary Equipment. Installed onto the Power Control Room Module are the following:

- Gas Turbine Lube Oil Cooler
- Neutral Ground Resistor
- Auxiliary Load Transformer

Power Control Room Trailer (Model TK70LCS)

- Two Axle Transport Trailer
- Trailer Length 46’ Overall
- Width 8’6”
- 49” 5^{th} wheel Height (loaded)
- Air Ride Suspension and Air Raise and Lower Kit

- Steel Disc Wheels with 255/70R x 22.5 Tires
- Three Tail Light Package
- Landing Gear
- 4 Additional Landing Gears with Soil Bearing Plates for Leveling/Stabilization at Site
- Overall Transport Height: 14'0"
- Approximate transport weight: 48,000 lbs. (without tractor)

On site commissioning

- Solar's Mobile Power Unit is designed for rapid setup and commissioning. The turbine package(s) proposed has been commissioned previously by Solar Factory Service Engineers. A checklist outlining the proposed setup & commissioning procedure is attached for your reference.

REVISIONS

ZONE	LTR.	DESCRIPTION	DATE	APPROVED
	B	RECORD DRAWING	03-30-01	DFH
	C	NOTES & DIMENSIONS ADDED BY PETERSON POWER SYSTEMS TO IMPROVE CLARITY.	1-15-03	GH

INSTRUMENTATION IDENTIFICATION

PXX – PRESSURE; PDX – DIFFERENTIAL; PDA – ALARM; PDS – SWITCH; PDAH – HIGH

FIRST LETTER MEASURED OR INITIATING VARIABLE

A – ANALYSIS
B – BURNER
C – USER'S CHOICE
D – USER'S CHOICE
E – VOLTAGE
F – FLOW RATE
G – USER'S CHOICE
H – HAND
I – CURRENT (ELECTRICAL)
J – POWER
K – TIME, TIME SCHEDULE
L – LEVEL
M – USER'S CHOICE
N – USER'S CHOICE
O – USER'S CHOICE
P – PRESSURE, VACUUM
Q – QUANTITY
R – RADIATION
S – SPEED FREQUENCY
T – TEMPERATURE
U – MULTIVARIABLE
V – VIBRATION
W – WEIGHT, FORCE
X – UNCLASSIFIED
Y – EVENT, STATE OR PRESENCE
Z – POSITION, DIMENSION

FIRST LETTER MODIFIER

D – DIFFERENTIAL
F – RATIO
J – SCAN
K – TIME RATE OF CHANGE
M – MOMENTARY
Q – INTEGRATE, TOTALIZE
S – SAFETY
X – X-AXIS
Y – Y-AXIS
Z – Z-AXIS

SUCCEEDING – LETTERS READOUT OR PASSIVE FUNCTION

A – ALARM
B – USER'S CHOICE
E – SENSOR (PRIMARY ELEMENT)
G – GLASS, VIEWING DEVICE
I – INDICATE
L – LIGHT
N – USER'S CHOICE
O – ORIFICE, RESTRICTION
P – POINT (TEST) CONNECTION
R – RECORD
U – MULTIFUNCTION
W – WELL
X – UNCLASSIFIED

SUCCEEDING – LETTERS OUTPUT FUNCTION

B – USER'S CHOICE
C – CONTROL
K – CONTROL STATION
N – USER'S CHOICE
S – SWITCH
T – TRANSMIT
U – MULTIFUNCTION
V – VALVE, DAMPER, LOUVER
X – UNCLASSIFIED
Y – RELAY, COMPUTE, CONVERT
Z – UNCLASSIFIED

SUCCEEDING – LETTERS MODIFIER

B – USER'S CHOICE
H – HIGH, VALVE OPEN
L – LOW, VALVE OPEN
M – MIDDLE, INTERMEDIATE
N – USER'S CHOICE
U – MULTIFUNCTION
X – UNCLASSIFIED

INSTRUMENTATION SYMBOLS

LOCAL FIELD MOUNTED DISCRETE INSTRUMENT
MAIN PANEL MOUNTED INSTRUMENT OR DEVICE
LOCAL PANEL MOUNTED INSTRUMENT OR DEVICE
SHARED DISPLAY, SHARED CONTROL THRU PLANT PLC.

INSTRUMENT & CONTROL INTERLOCKS

I – INTERLOCK TO LOCAL CONTROL OR COMPUTERS
B – BALANCE OF PLANT LOGIC

CONTINUATION ARROWS

SYSTEM/LINE NUMBER – TO OTHER P & ID
SYSTEM/LINE NUMBER – FROM OTHER P & ID
FLOW CONTINUATION ARROW (BI-DIRECTIONAL)

PIPING LINE NUMBER

XX-XXX-XXX-XXXXX-XX
INSULATION: IH = HEAT CONSERVATION; IC = COLD INSULATION; PP = PERSONNEL PROTECTION
LINE NUMBER
SERVICE / COMMODITY
PIPE SCHEDULE OR WALL THICKNESS
PIPING MATERIAL IDENTIFICATION
LINE SIZE

PIPING & INSTRUMENT LINES

EXISTING SYSTEM
PRIMARY SYSTEM
SECONDARY SYSTEM
DATA LINK
ELECTRIC SIGNAL
PNEUMATIC SIGNAL
HYDRAULIC SIGNAL

ABBREVIATIONS

ABBREV.	DESCRIPTION
A/C	ASPHALT CONCRETE
BLDG.	BUILDING
℄	CENTER LINE
C.L.	CHAIN LINK
COMP.	COMPRESSOR
CONC.	CONCRETE
CMU	CONCRETE MASONRY UNIT
CONN.	CONNECTION
CONT.	CONTINUOUS
CPLG.	COUPLING
CU. FT.	CUBIC FEET
DIA. OR ø	DIAMETER
DEPT.	DEPARTMENT
DWG.	DRAWING
EA.	EACH
ECC.	ECCENTRIC
ELEV.	ELEVATION
E.O.	EDGE OF
ESD	EMERGENCY SHUTDOWN
ESDPB	EMERGENCY SHUTDOWN PUSH BUTTON
ENCL.	ENCLOSURE
EXIST.	EXISTING
F.C.	FAIL CLOSED
F.O.	FAIL OPEN
F.P.T.	FEMALE PIPE THREADED
F.F.	FLAT FACE
F.O.B.	FLAT ON BOTTOM
F.O.T.	FLAT ON TOP
FIG.	FIGURE
F.M.U.	FITTING MAKE-UP
FLG.	FLANGE
FT.	FOOT
F.O.M.	FACE OF MASONRY
GALV.	GALVANIZED
GND.	GROUND
H	HIGH
H.P.	HIGH PRESSURE
HORIZ.	HORIZONTAL
I.D.	INSIDE DIAMETER
L/S	LANDSCAPE
KVA	KILOVOLT – AMPS
LAV.	LAVATORY
L.C.	LOCKED CLOSED
L.O.	LOCKED OPEN
L	LONG
M.B.	MACHINE BOLT
M/U	MAKE-UP
M.O.	MASONRY OPENING
MAX.	MAXIMUM
MIN.	MINIMUM
M.P.T.	MALE PIPE THREAD
MTR.	MOTOR
NPT	NATIONAL PIPE THREAD
N/A	NOT APPLICABLE
N.C.	NORMALLY CLOSED
N.O.	NORMALLY OPEN
N.T.S.	NOT TO SCALE
NO.	NUMBER
O.C.	ON CENTER
P/N	PART NUMBER
℘	PLATE
P.B.E.	PLAIN BOTH ENDS
P.O.E.	PLAIN ONE END
P.O.C	POINT OF CONNECTION
PE.	POLYETHYLENE
PVC.	POLYVINYLCHLORIDE
#	POUND
PSI	POUNDS PER SQUARE INCH
P.B.	PUSH BUTTON
R.F.	RAISED FACE
RED.	REDUCING
REF.	REFERENCE
RCP	REINFORCED CONCRETE PIPE
REINF.	REINFORCEMENT
SCH.	SCHEDULE
SEC.	SECTION
SIM.	SIMILAR
SPR.	SPRINKLERED
SQ.	SQUARE
SQ. FT.	SQUARE FEET
SCFH	STANDARD CUBIC FEET PER HOUR
STD.	STANDARD
SS	STAINLESS STEEL
THK.	THICK
THD.	THREADED
THRU.	THROUGH
XFMR OR XFORMER	TRANSFORMER
TYP.	TYPICAL
U/G	UNDERGROUND
U.O.N.	UNLESS OTHERWISE NOTED
VERT.	VERTICAL
W	WIDE
W/	WITH

MISCELLANEOUS SYMBOLS

ITEM	DESCRIPTION
	CORIOLIS FLOW METER
	ORIFICE
	TURBINE FLOW METER
	FLANGE
	UNION
	CAP WELDED
	CAP THREADED OR SOCKET WELDED
	BLIND FLANGE
	HOSE CONNECTION
	CONCENTRIC REDUCER
	ECCENTRIC REDUCER
	FLEXIBLE CONNECTOR
	EXPANSION JOINT (BELLOWS TYPE)
	INSULATED LINE
E	ELECTRIC HEAT TRACED LINE
	Y-TYPE STRAINER
	CENTRIFUGAL PUMP
OR	POSITIVE DISPLACEMENT PUMP
	EDUCTOR
	CENTRIFUGAL FAN
	AXIAL FAN
	POINT OF CONNECTION
LC	LOCKED CLOSED
LO	LOCKED OPEN
NC	NORMALLY CLOSED
NO	NORMALLY OPEN
CS – CS	SPEC/SCOPE OF SUPPLY BREAK
CU	COPPER
CS	CARBON STEEL
SS	STAINLESS STEEL
IA	INSTRUMENTS AIR SUPPLY

VALVE SYMBOLS

OPEN	CLOSED	TYPE
		ANGLE
		BALL
	NC	BUTTERFLY
	N/A	CHECK
		GATE OR UNSPECIFIED
		GAUGE ROOT (W/INTEGRAL VENT)
		GLOBE
		NEEDLE
		PLUG
		REGULATING (FLOW)
	N/A	SAFETY/RELIEF
	N/A	STOP-CHECK (NON-RETURN) (ANGLE)
	N/A	STOP-CHECK (NON-RETURN) (Y-PATTERN)
		THREE-WAY
		FOUR-WAY

CONTROL VALVE OPERATORS

FC = FAIL CLOSED
FO = FAIL OPEN
TYPICAL FOR ALL CONTROL VALVES

DIAPHRAGM OPERATED
PISTON OPERATED
MOTOR OPERATED
ELECTRO/HYDRAULIC MOTOR OPERATED
SOLENOID OPERATED
OPERATOR WITH HANDWHEEL
SELF-CONTAINED PRESSURE REGULATOR
SELF-CONTAINED BACKPRESSURE PRESSURE REGULATOR
PILOT OPERATED PRESSURE REGULATOR

PIPING MATERIAL IDENTIFICATION

PRESSURE CLASS	MATERIAL	ENDS
A – 150#	1 – CARBON STEEL	0 – RAISED
B – 300#	2 – LOW TEMPERATURE	1 – FLAT FACE
C – 400#	3 – COPPER OR BRONZE	2 – RING TYPE JOINT
D – 600#	4 – GALVANIZED	3 – SCREWED END
E – 900#	5 – 304 STAINLESS STEEL	4 – SOCKET-WELD END
F – 1500#	6 – NACE SPEC.	5 – BUTT-WELD END
G – 2500#	7 – 316 L STAINLESS STEEL	6 – WAFER
S – OPEN ATMOSPHERE	8 – SPECIAL	7 – SPECIAL
T – TO BE ESPECIFIED AS REQUIRED	9 – SPECIAL	8 – SPECIAL
		9 – SPECIAL

SERVICE / COMMODITY

P – PROCESS GAS AND LIQUID
EX – EXHAUST
D – DRAIN
A – AIR
CW – COOLING WATER
F – FUEL GAS AND LIQUID
PW – POTABLE WATER
S – STEAM
FW – FEED WATER
LO – LUBE OIL
V – VENT AND FLARE
CF – CLEANING FLUID
FE – FIRE EXTINGUISHANT
TW – TREATED (DEMINERALIZED) WATER

PETERSON POWER SYSTEMS INC.
2718 TEAGARDEN STREET
SAN LEANDRO, CA 94577

PID Engineering
Power and Industrial Design Corporation
9625 BLACK MOUNTAIN ROAD SUITE 308
SAN DIEGO, CA 92126 PHONE: (858) 348-3200

Solar Turbines
A Caterpillar Company
P.O. Box 85376
San Diego, California 92186-5376

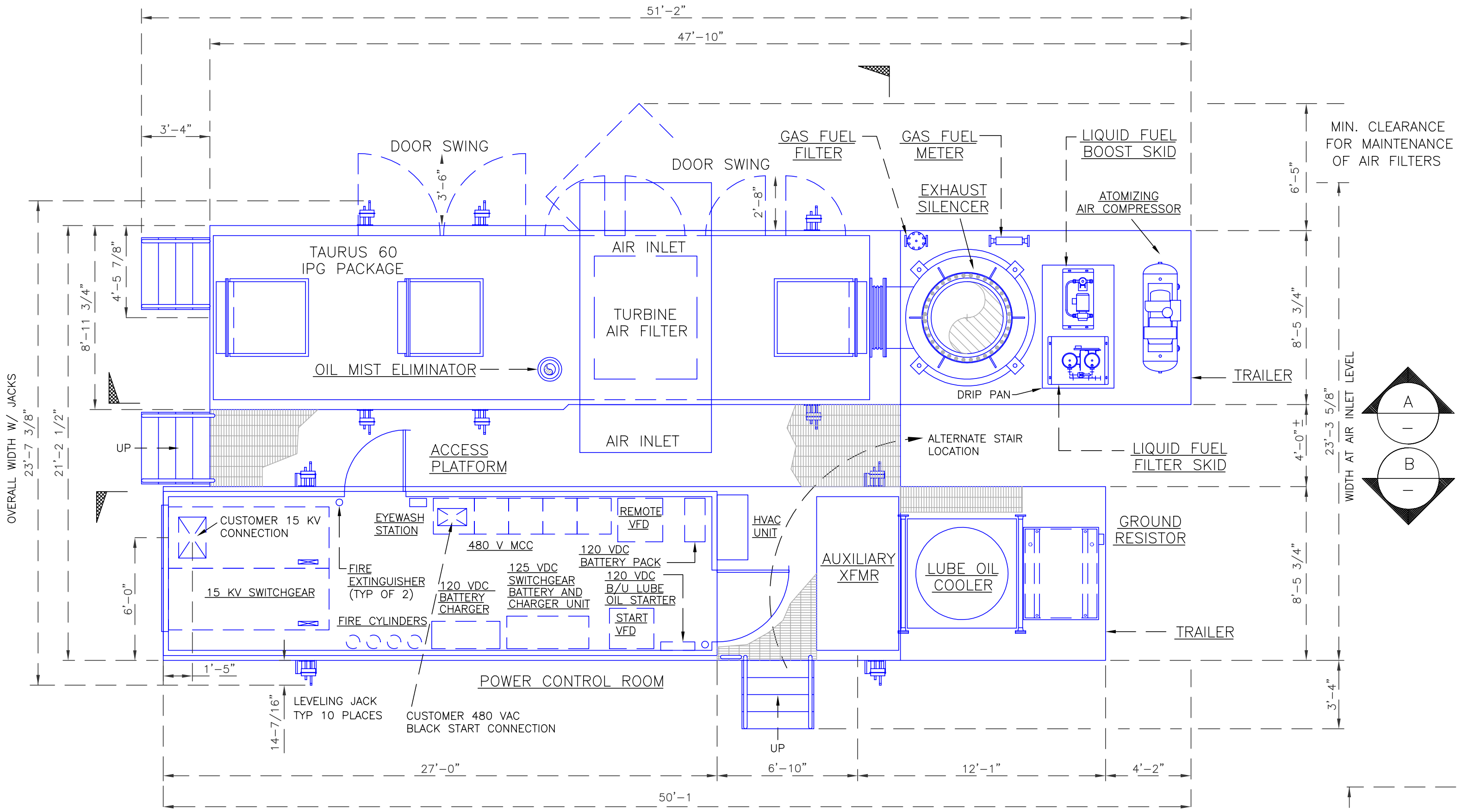
DATA CONTROL LEVEL	RELEASE STAMP	CONTRACT NO.	
		DFTR. G MENDOZA	11-30-00
		CHKR. J PLESCIA	12-22-00
		LYT.	
MODEL LEVEL		ENGR. D.F. HAAS	11-30-00
LAYOUT		ME	
NHA		PLOT DATE	03-30-01
MODEL		PLOT SCALE	1=1
CADDS IDENT. 59731F001		CUSTOMER	

LEGEND SHEET
TAURUS 60 – DUAL FUEL
MOBILE UNIT

SIZE	CAGE NO.	DWG. NO.	
D		59731-1500-F001	
SCALE: NONE		TOTAL WT.	SHEET OF

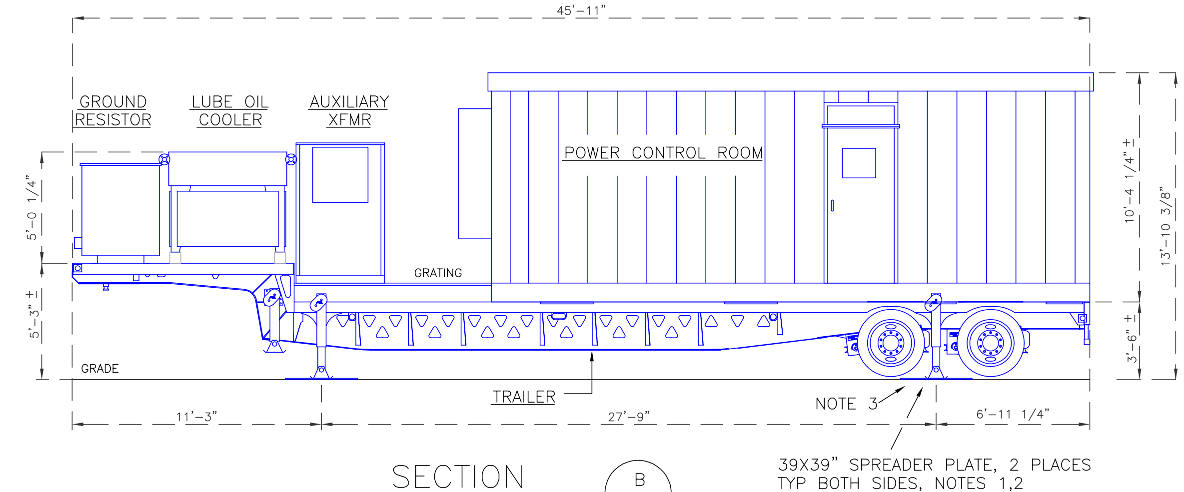
REVISIONS

ZONE	LTR.	DESCRIPTION	DATE	APPROVED
	A	ISSUED FOR REVIEW	12-22-00	DFH
	B	RECORD DRAWING	03-30-01	DFH
	C	ROTATED GENERATOR EXHAUST ELBOW SILENCER	05-22-01	DFH
	D	NOTES & DIMENSIONS ADDED BY PETERSON POWER SYSTEMS TO IMPROVE CLARITY.	1-15-03	GH



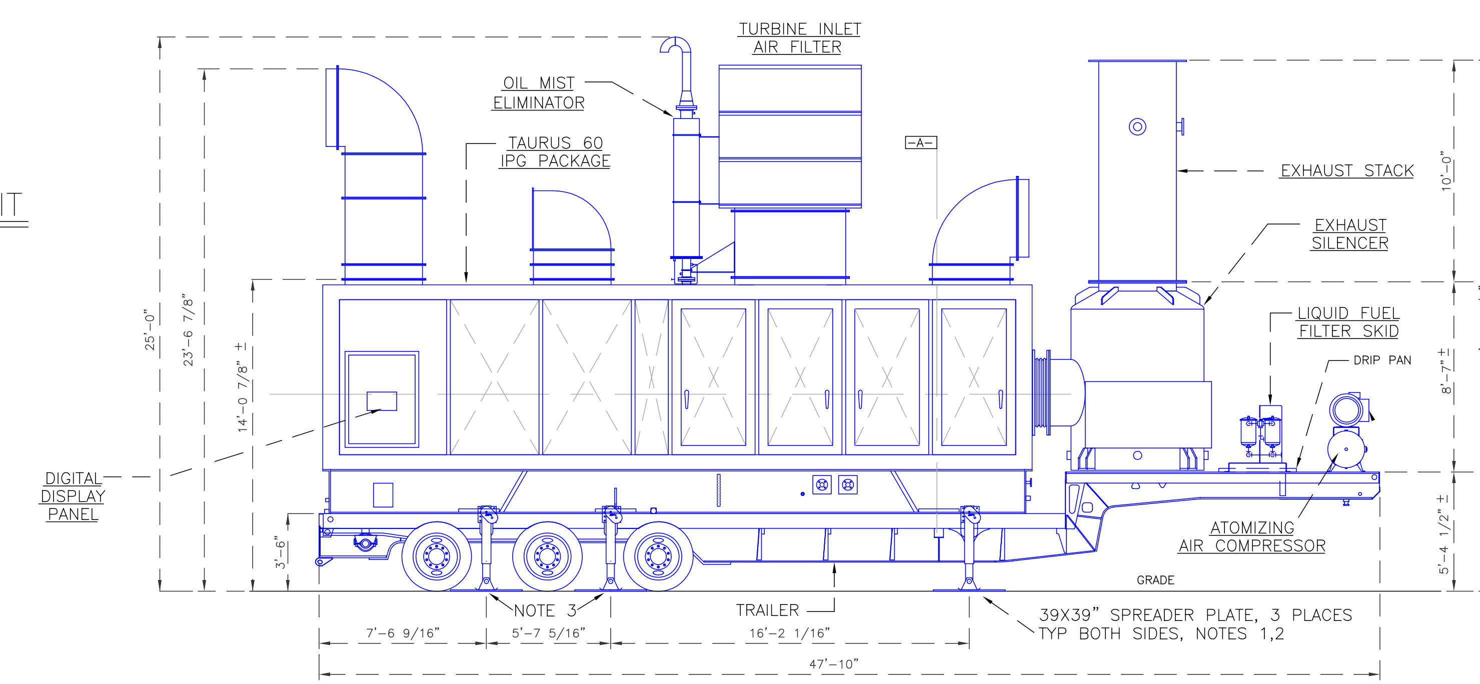
EQUIPMENT GENERAL ARRANGEMENT PLAN – TAURUS 60 MOBILE UNIT

SCALE: 1/4" = 1'-0"



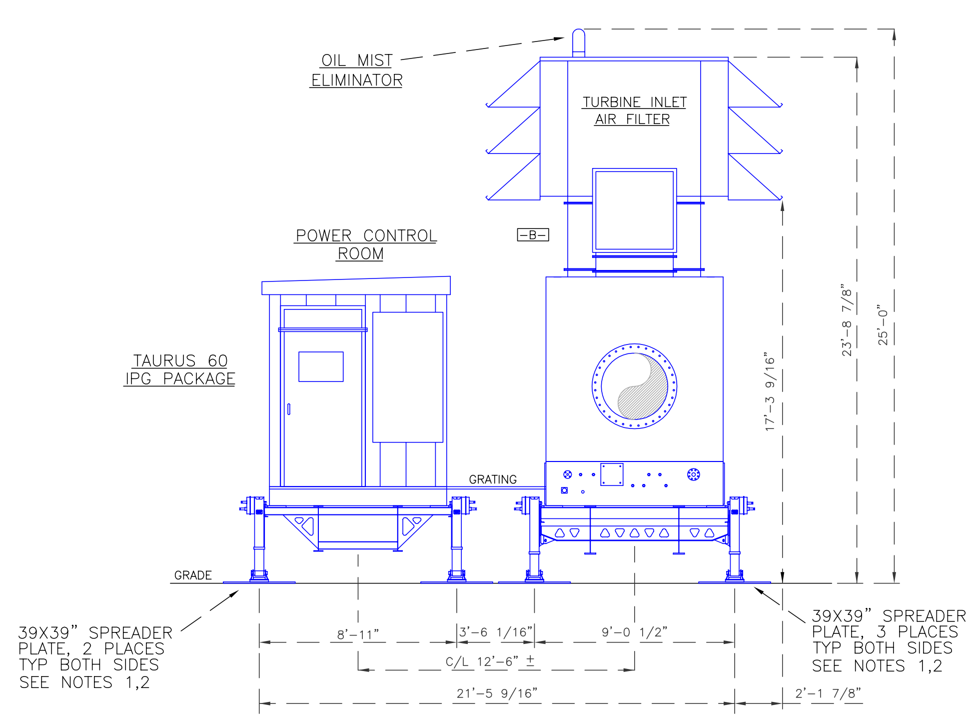
SECTION B

SCALE: 1/4" = 1'-0"



SECTION A

SCALE: 1/4" = 1'-0"



SECTION C

SCALE: 1/4" = 1'-0"

NOTES:

1. SPREADER PLATES ARE PROVIDED BY SOLAR
2. SOIL COMPACTION SHALL BE A MINIMUM OF 2500 LBS/SQ.FT. TO SUPPORT TRAILER PACKAGE.
3. SPREADER PLATES ORIENTED ON THE DIAGONAL AT THIS LOCATION TO AVOID TIRE INTERFERENCE. TYP. BOTH SIDES.

PETERSON POWER SYSTEMS INC.
2718 TEAGARDEN STREET
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Solar Turbines
A Caterpillar Company
P.O. Box 85376
San Diego, California 92186-5376

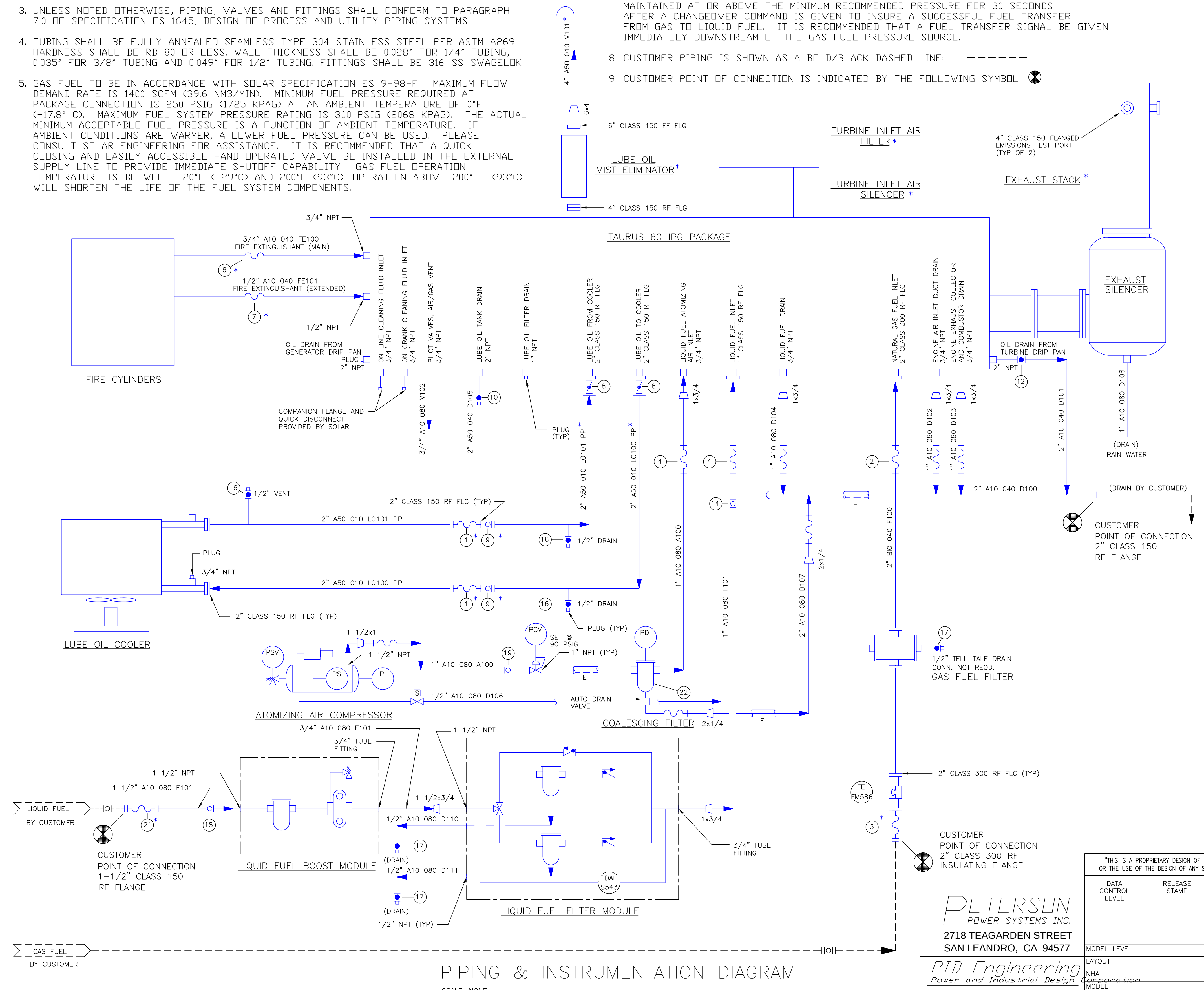
DATA CONTROL LEVEL	RELEASE STAMP	CONTRACT NO.
DFTR.	DFH	12-08-00
CHKR.	J PLESCIA	12-22-00
LYT.		
ENGR.	D F HAAS	12-08-00
MODEL LEVEL		
LAYOUT		
ME		
NHA MODEL		
PLOT DATE		03-30-01
PLOT SCALE		1=48
CADDS IDENT.	59731M001	
CUSTOMER		

EQUIPMENT ARRANGEMENT PLANS AND SECTIONS
TAURUS 60 – DUAL FUEL
MOBILE UNIT

SIZE	CAGE NO.	DWG. NO.
D		59731-1500-M001
SCALE: NOTED	TOTAL WT.	SHEET OF

NOTES:

1. EQUIPMENT NOTED WITH AN ASTERISK (*) IS PROVIDED BY SOLAR, INSTALLED IN THE FIELD.
2. PIPING MATERIALS ARE IDENTIFIED PER SOLAR TURBINE'S LINE NUMBERING SYSTEM PER PARAGRAPH 6.0 OF THE SPECIFICATION ES-1645, DESIGN OF PROCESS AND UTILITY PIPING SYSTEMS.
3. UNLESS NOTED OTHERWISE, PIPING, VALVES AND FITTINGS SHALL CONFORM TO PARAGRAPH 7.0 OF SPECIFICATION ES-1645, DESIGN OF PROCESS AND UTILITY PIPING SYSTEMS.
4. TUBING SHALL BE FULLY ANNEALED SEAMLESS TYPE 304 STAINLESS STEEL PER ASTM A269. HARDNESS SHALL BE RB 80 OR LESS. WALL THICKNESS SHALL BE 0.028" FOR 1/4" TUBING, 0.035" FOR 3/8" TUBING AND 0.049" FOR 1/2" TUBING. FITTINGS SHALL BE 316 SS SWAGELOK.
5. GAS FUEL TO BE IN ACCORDANCE WITH SOLAR SPECIFICATION ES 9-98-F. MAXIMUM FLOW DEMAND RATE IS 1400 SCFM (39.6 NM3/MIN). MINIMUM FUEL PRESSURE REQUIRED AT PACKAGE CONNECTION IS 250 PSIG (1725 KPAG) AT AN AMBIENT TEMPERATURE OF 0°F (-17.8° C). MAXIMUM FUEL SYSTEM PRESSURE RATING IS 300 PSIG (2068 KPAG). THE ACTUAL MINIMUM ACCEPTABLE FUEL PRESSURE IS A FUNCTION OF AMBIENT TEMPERATURE. IF AMBIENT CONDITIONS ARE WARMER, A LOWER FUEL PRESSURE CAN BE USED. PLEASE CONSULT SOLAR ENGINEERING FOR ASSISTANCE. IT IS RECOMMENDED THAT A QUICK CLOSING AND EASILY ACCESSIBLE HAND OPERATED VALVE BE INSTALLED IN THE EXTERNAL SUPPLY LINE TO PROVIDE IMMEDIATE SHUTOFF CAPABILITY. GAS FUEL OPERATION TEMPERATURE IS BETWEET -20°F (-29°C) AND 200°F (93°C). OPERATION ABOVE 200°F (93°C) WILL SHORTEN THE LIFE OF THE FUEL SYSTEM COMPONENTS.
6. LIQUID FUEL IS TO BE IN ACCORDANCE WITH SOLAR SPECIFICATION ES 9-98. MAXIMUM LIQUID FUELFLOW DEMAND IS 8.0 GPM (30.3 LITERS/MIN). FUEL SUPPLY PRESSURE AT PACKAGE CONNECTION MUST BE REGULATED BETWEEN 20' (6096 MM) WET SUCTION LIFT TO 25 PSIG (171.7 KPAG).MAXIMUM ALLOWABLE LIQUID FUEL TEMPERATURE IS 140°F (60°C).
7. ON DUAL FUEL UNITS, THE GAS FUEL PRESSURE AT THE PACKAGE CONNECTION MUST BE MAINTAINED AT OR ABOVE THE MINIMUM RECOMMENDED PRESSURE FOR 30 SECONDS AFTER A CHANGEOVER COMMAND IS GIVEN TO INSURE A SUCCESSFUL FUEL TRANSFER FROM GAS TO LIQUID FUEL. IT IS RECOMMENDED THAT A FUEL TRANSFER SIGNAL BE GIVEN IMMEDIATELY DOWNSTREAM OF THE GAS FUEL PRESSURE SOURCE.
8. CUSTOMER PIPING IS SHOWN AS A BOLD/BLACK DASHED LINE: — — — — — —
9. CUSTOMER POINT OF CONNECTION IS INDICATED BY THE FOLLOWING SYMBOL:



PIPING & INSTRUMENTATION DIAGRAM

SCALE: NONE

DWG. NO. 59731-1500-F002 SH. REV.

REVISIONS

ZONE	LTR.	DESCRIPTION	DATE	APPROVED
	A	ISSUED FOR REVIEW	12-22-00	DFH
	B	RECORD DRAWING	03-30-01	DFH
	C	NOTES & DIMENSIONS ADDED BY PETERSON POWER SYSTEMS TO IMPROVE CLARITY.	1-15-03	GH

BILL OF MATERIAL

MARK	QTY	DESCRIPTION
1	2	LUBE OIL FLEXIBLE HOSE, GOODYEAR SUPER BLACK FLEXWING HIGH PRESSURE PETROLEUM TRANSFER HOSE, SYNTHETIC RUBBER (ORS) TUBE AND COVER WITH SYNTHETIC FABRIC AND WIRE REINFORCEMENT, 2" ID, 2.74" OD, 35 FEET LONG, RATED AT 250 PSIG AT 200 DEG F. PROVIDE 2" CLASS 150 LAP JOINT FLANGES WITH 90 DEG ELBOWS AT EACH END. SEE DETAIL 1, SHEET P002. ALL WETTED METAL SURFACES SHALL BE 304 SS.
2	1	FUEL GAS FLEXIBLE METAL HOSE, SINGLE BRAID CORRUGATED METAL HOSE, 2" ID 321 STAINLESS STEEL ANNULAR INNER CORE, 304L STAINLESS STEEL BRAID, 2" SCHEDULE 40 CARBON STEEL BUTT WELD ENDS, 12 1/2" LIVE HOSE LENGTH, 18" OVERALL HOSE LENGTH, 740 PSIG DESIGN PRESSURE AT 100 DEG. F.
3	1	FUEL GAS FLEXIBLE METAL HOSE, SINGLE BRAID CORRUGATED METAL HOSE 2" ID 321 STAINLESS STEEL ANNULAR INNER CORE, 304L STAINLESS STEEL BRAID, 2" CARBON STEEL SCH 40 CLASS 300 RF FLANGE ON ONE END WITH A 2" CARBON STEEL SCH 40 CLASS 300 FLOATING FLANGE ON THE OTHER END, 11 3/8" LIVE HOSE LENGTH, 18" OVERALL LENGTH, 740 PSIG DESIGN PRESSURE AT 100 DEG. F.
4	2	LIQUID FUEL AND AIR FLEXIBLE METAL HOSE, SINGLE BRAID CORRUGATED METAL HOSE 1" ID 321 STAINLESS STEEL ANNULAR INNER CORE, 304L STAINLESS STEEL BRAID, 1" CARBON STEEL SCH 40 MALE NPT NIPPLE CONNECTION ON ONE END WITH A 1" CARBON STEEL FEMALE UNION ON THE OTHER END, 8" LIVE HOSE LENGTH, 14" OVERALL LENGTH, 285 PSIG DESIGN PRESSURE AT 100 DEG. F.
5		NOT USED
6	1	FIRE EXTINGUISHANT (CO_2) FLEXIBLE METAL HOSE, SINGLE BRAID CORRUGATED METAL HOSE 3/4" ID 321 STAINLESS STEEL ANNULAR INNER CORE, 304L STAINLESS STEEL BRAID, 3/4" CARBON STEEL SCH 40 MALE NPT NIPPLE CONNECTION ON ONE END WITH A 3/4" CARBON STEEL FEMALE UNION ON THE OTHER END, " LIVE HOSE LENGTH, " OVERALL LENGTH, 285 PSIG DESIGN PRESSURE AT 100 DEG. F.
7	1	FIRE EXTINGUISHANT (CO_2) FLEXIBLE METAL HOSE, SINGLE BRAID CORRUGATED METAL HOSE 1/2" ID 321 STAINLESS STEEL ANNULAR INNER CORE, 304L STAINLESS STEEL BRAID, 1/2" CARBON STEEL SCH 40 MALE NPT NIPPLE CONNECTION ON ONE END WITH A 1/2" CARBON STEEL FEMALE UNION ON THE OTHER END, " LIVE HOSE LENGTH, " OVERALL LENGTH, 285 PSIG DESIGN PRESSURE AT 100 DEG. F.
8	2	2" LUBE OIL CLASS 150 LUGGED BUTTERFLY VALVE SHALL BE MILWAUKEE ML234V, DUCTILE IRON BODY, 316 STAINLESS STEEL DISC, VITON SEAT, LEVER HANDLE, LUGGED BODY STYLE FOR DEAD END SERVICE.
9	2	2" LUBE OIL BALL VALVE, 316 STAINLESS STEEL BODY, BALL AND TRIM, FLOATING OR TRUNNION MOUNTED BALL, API-607 FIRE SAFE DESIGN, LEVER OPERATED, STANDARD BORE, CLASS 150 FLANGED ENDS, NELES-JAMESBURY SERIES 5000, 5150-31-3636TT OR EQUAL.
10	1	2" LUBE OIL TANK DRAIN BALL VALVE, CARBON STEEL BODY, 316 STAINLESS STEEL BALL AND TRIM, 2-PIECE BODY, API-607 FIRE SAFE DESIGN, LEVER OPERATED, FULL BORE, THREADED ENDS, NELES-JAMESBURY SERIES 6F, 6F-2236TT OR EQUAL.
11		NOT USED
12	1	2" TURBINE DRIP PAN BALL VALVE, BRASS BODY, 316 STAINLESS STEEL BALL AND TRIM, TFE SEATS, 2-PIECE BODY, LEVER OPERATED, STANDARD BORE, NELES-JAMESBURY SERIES 300, FIGURE 346 OR EQUAL.
13		NOT USED
14	1	1" LIQUID FUEL BALL VALVE, CARBON STEEL BODY, 316 STAINLESS STEEL BALL AND TRIM, 3-PIECE BODY, API-607 FIRE SAFE DESIGN, LEVER OPERATED, FULL BORE, THREADED ENDS, NELES-JAMESBURY SERIES 4000, 4B-2236TT OR EQUAL.
15		NOT USED
16	3	1/2" LUBE OIL VENT BALL VALVE, CARBON STEEL BODY, 316 STAINLESS STEEL BALL AND TRIM, 2-PIECE BODY, API-607 FIRE SAFE DESIGN, LEVER OPERATED, FULL BORE, THREADED ENDS, NELES-JAMESBURY SERIES 6F, 6F-2236TT OR EQUAL.
17	3	1/2" LIQUID AND GAS FUEL DRAIN BALL VALVE, CARBON STEEL BODY, 316 STAINLESS STEEL BALL AND TRIM, 2-PIECE BODY, API-607 FIRE SAFE DESIGN, LEVER OPERATED, FULL BORE, THREADED ENDS, NELES-JAMESBURY SERIES 6F, 6F-2236TT OR EQUAL.
18	1	1 1/2" LIQUID FUEL BALL VALVE, CARBON STEEL BODY, 316 STAINLESS STEEL BALL AND TRIM, 3-PIECE BODY, API-607 FIRE SAFE DESIGN, LEVER OPERATED, FULL BORE, THREADED ENDS, NELES-JAMESBURY SERIES 4000, 4B-2236TT OR EQUAL.
19	1	1" ATOMIZING AIR BALL VALVE, BRASS BODY, BRASS BALL AND TRIM, TFE SEATS, 2-PIECE BODY, AUTOMATIC DOWNSTREAM VENTING WHEN VALVE IS CLOSED, LEVER OPERATED, STANDARD BORE, THREADED ENDS, NELES-JAMESBURY SERIES 371 OR EQUAL.
20		NOT USED
21	1	LIQUID FUEL FLEXIBLE METAL HOSE, SINGLE BRAID CORRUGATED METAL HOSE 1 1/2" ID 321 STAINLESS STEEL ANNULAR INNER CORE, 304L STAINLESS STEEL BRAID, 1 1/2" CARBON STEEL SCH 80 CLASS 150 RF FLANGE ON ONE END WITH A 1 1/2" CARBON STEEL SCH 80 CLASS 150 FLOATING FLANGE ON THE OTHER END, 12 1/4" LIVE HOSE LENGTH, 18" OVERALL LENGTH, 285 PSIG DESIGN PRESSURE AT 100 DEG. F.
22	1	ATOMIZING AIR COALESCING FILTER, ALUMINUM BODY WITH 1" NPT CONNECTIONS, DIFFERENTIAL PRESSURE INDICATOR, AUTOMATIC DRAIN VALVE, BLEED VALVE, 1 MICRON ELEMENT, RATED 170 SCFM AT 100 PSIG, SULLAIR MODEL MPF-170N.

PETERSON POWER SYSTEMS INC.
2718 TEAGARDEN STREET
SAN LEANDRO, CA 94577

PID Engineering Power and Industrial Design Corporation
9625 BLACK MOUNTAIN ROAD SUITE 308
SAN DIEGO, CA 92126 PHONE: (858) 348-3200

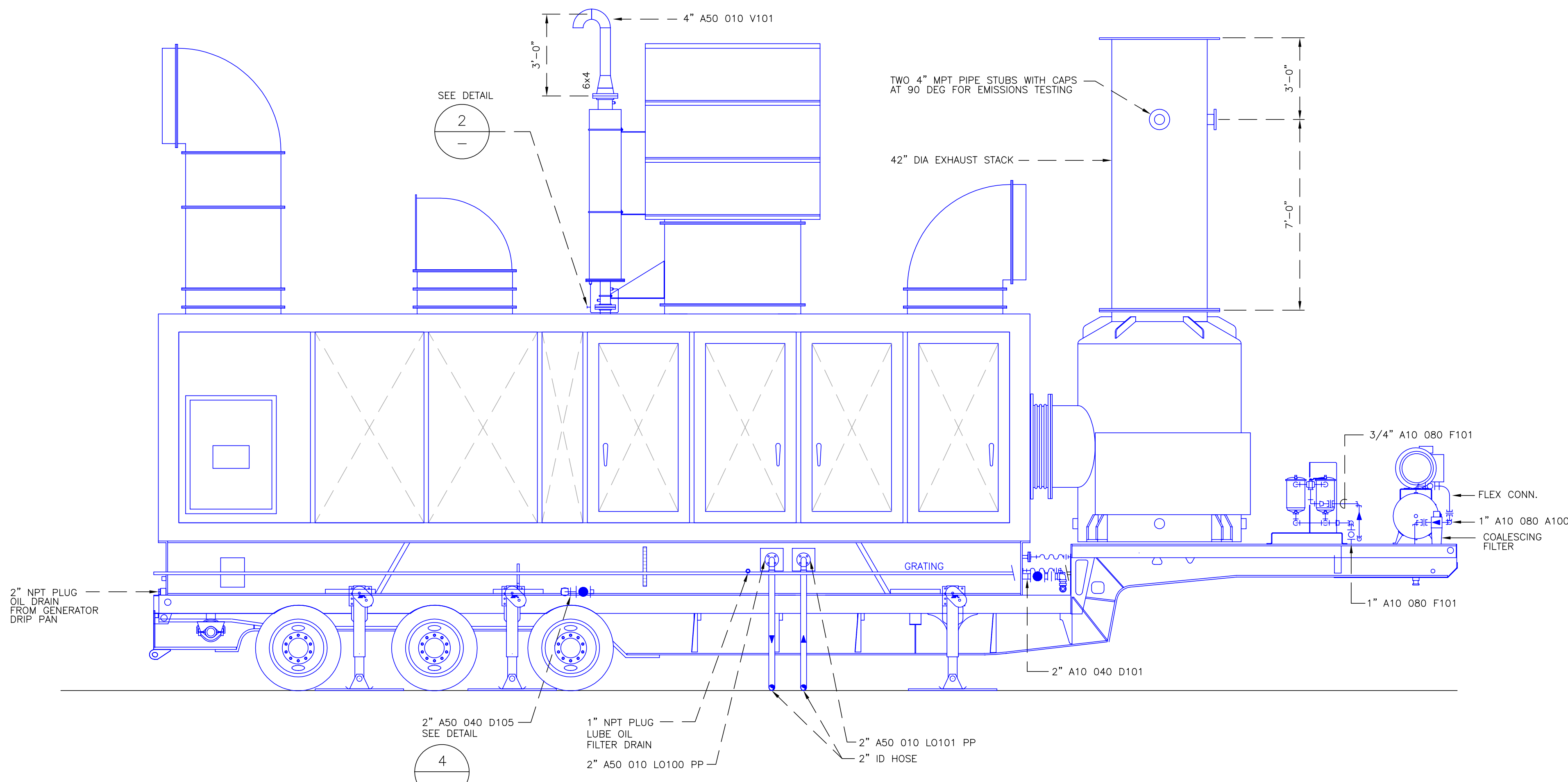
Solar Turbines
A Caterpillar Company
P.O. Box 85376
San Diego, California 92186-5376

DATA CONTROL LEVEL	RELEASE STAMP	CONTRACT NO.
DFTR.	DFH	11-30-00
CHKR.	J PLESCIA	12-22-00
LYT.		
ENGR.	D.F. HAAS	11-30-00
MODEL LEVEL		
LAYOUT		
ME		
NHA		
PLOT DATE		03-30-01
MODEL		
PLOT SCALE		1=1
CADDS IDENT. 59731F002		CUSTOMER

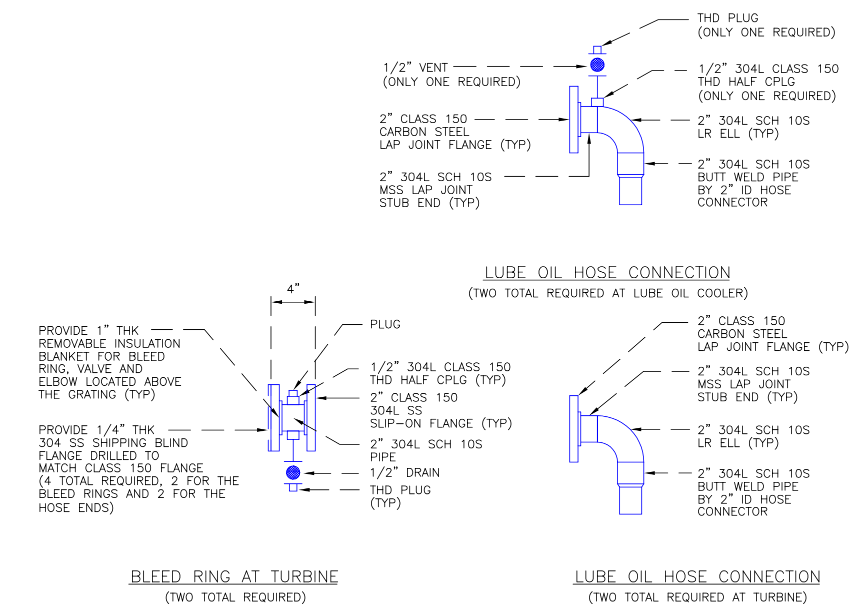
PIPING & INSTRUMENTATION DIAGRAM
TAURUS 60 – DUAL FUEL
MOBILE UNIT

SIZE	CAGE NO.	DWG. NO.
D		59731-1500-F002
SCALE: NONE	TOTAL WT.	SHEET OF

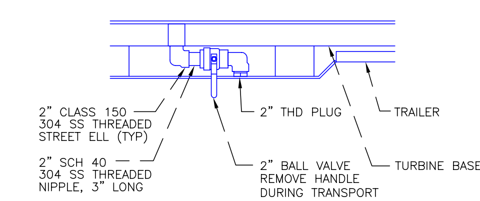
ZONE	LTR.	DESCRIPTION	DATE	APPROVED
	A	ISSUED FOR REVIEW	12-22-00	DFH
	B	RECORD DRAWING	03-30-01	DFH
	C	ROTATED GENERATOR EXHAUST ELBOW SILENCER	05-22-01	DFH
	D	NOTES & DIMENSIONS ADDED BY PETERSON POWER SYSTEMS TO IMPROVE CLARITY	1-15-03	GH



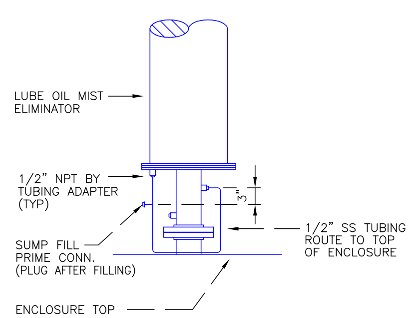
PIPING SECTION D / P001
SCALE: 3/8" = 1'-0"



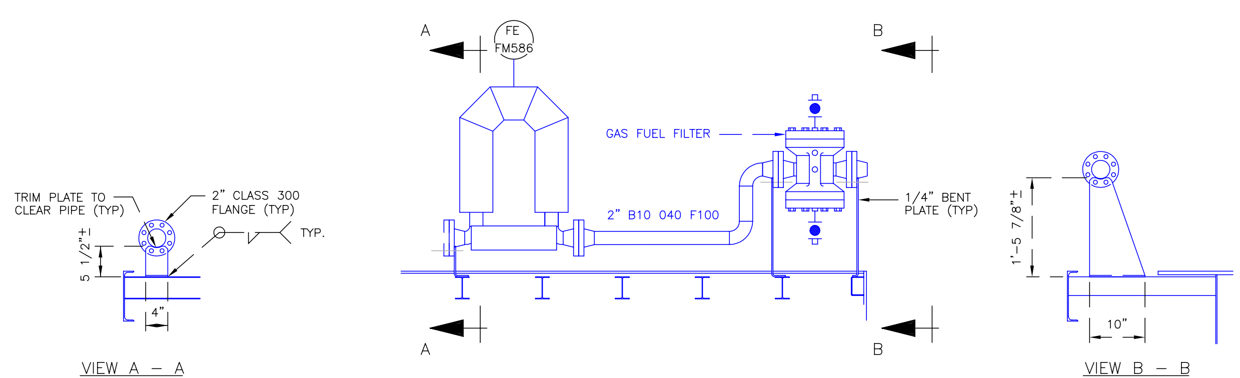
DETAIL – LUBE OIL PIPING 1 / P001
SCALE: 1 1/2" = 1'-0"



DETAIL – LUBE OIL TANK DRAIN 4 / –
SCALE: 3/4" = 1'-0"



DETAIL – PRIME CONN. 2 / –
SCALE: 3/4" = 1'-0"



DETAIL – PIPE SUPPORT 3 / P001
SCALE: 3/4" = 1'-0"

PETERSON POWER SYSTEMS INC.
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Solar Turbines
A Caterpillar Company
P.O. Box 85376
San Diego, California 92186-5376

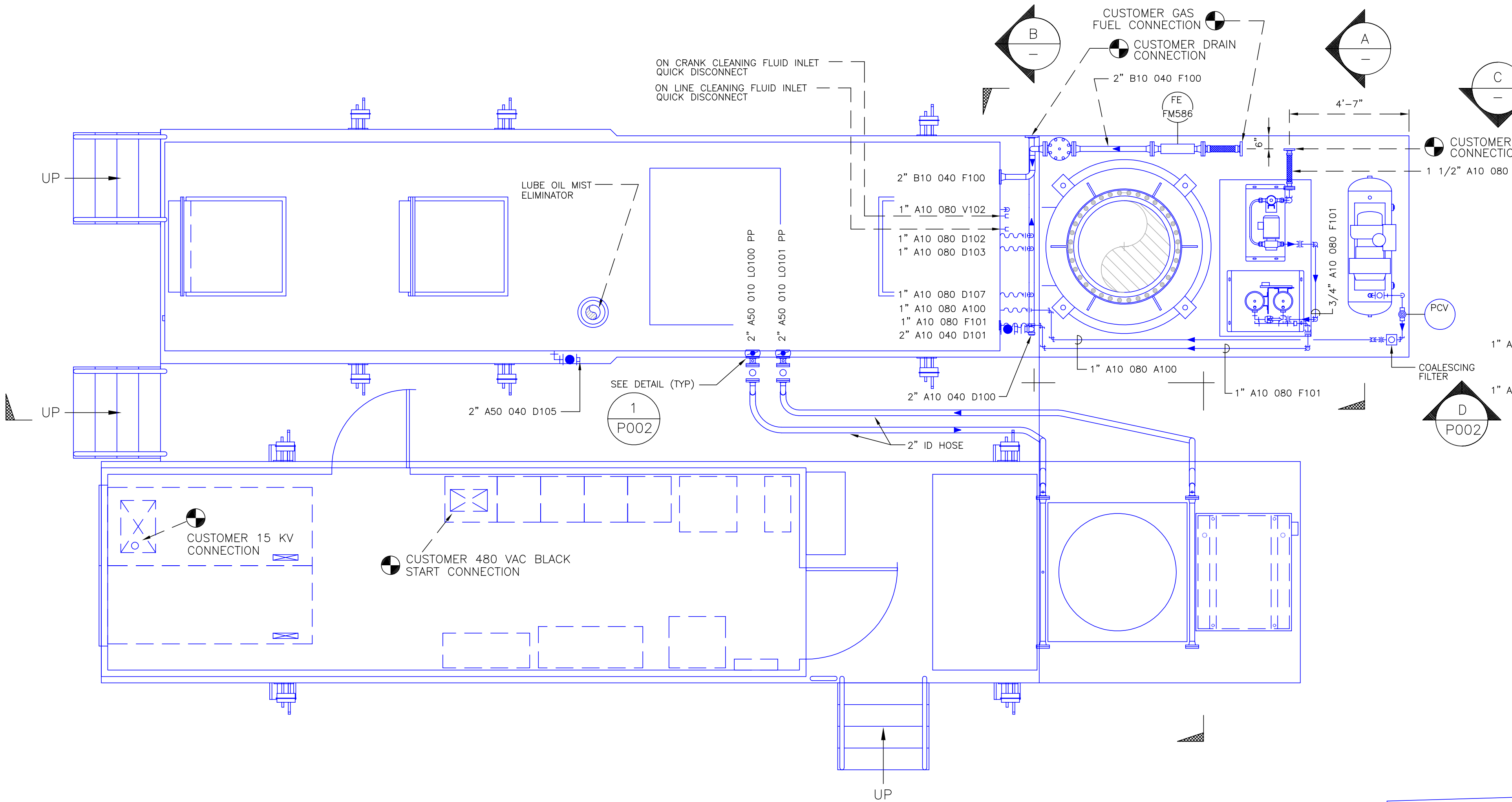
DATA CONTROL LEVEL	RELEASE STAMP	CONTRACT NO.
DFTR.	DFH	12-12-00
CHKR.	J PLESCIA	12-22-00
LYT.		
ENGR.	D F HAAS	12-12-00
MODEL LEVEL		
LAYOUT		ME
NHA	PLOT DATE	03-30-01
MODEL	PLOT SCALE	1=32
CADDS IDENT. 59731P002	CUSTOMER	

PIPING SECTION & DETAILS
TAURUS 60 – DUAL FUEL
MOBILE UNIT

SIZE: D | CAGE NO. | DWG. NO. 59731-1500-P002
SCALE: NOTED | TOTAL WT. | SHEET OF

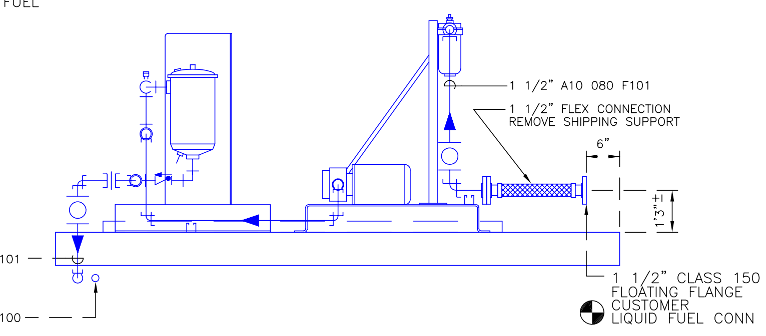
REVISIONS

ZONE	LTR.	DESCRIPTION	DATE	APPROVED
	A	ISSUED FOR REVIEW	12–22–00	DFH
	B	RECORD DRAWING	03–30–01	DFH
	C	ROTATED GENERATOR EXHAUST ELBOW SILENCER	05–22–01	DFH
	D	NOTES & DIMENSIONS ADDED BY PETERSON POWER SYSTEMS TO IMPROVE CLARITY	1–15–03	GH



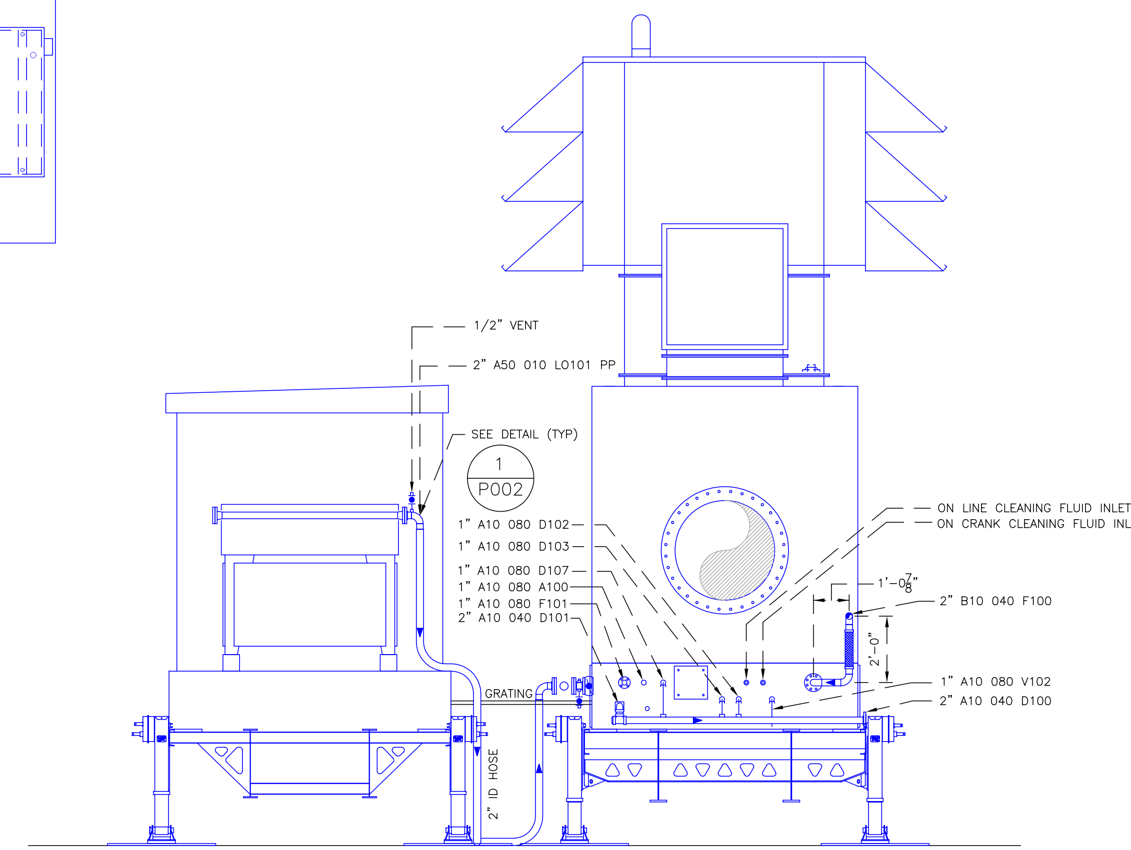
PIPING PLAN

SCALE: 3/8" = 1'–0"



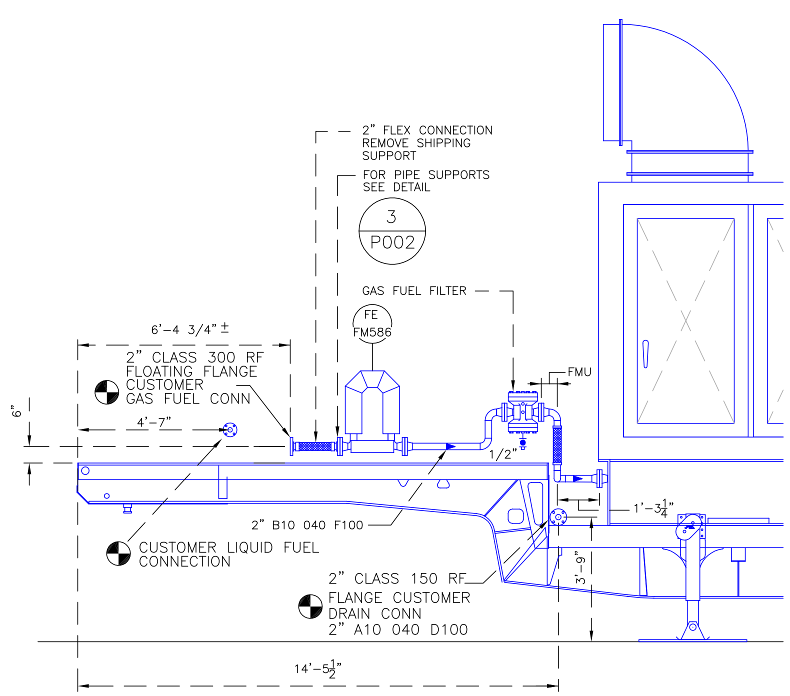
PIPING SECTION A

SCALE: 3/4" = 1'–0"



PIPING SECTION B

SCALE: 3/8" = 1'–0"



PIPING SECTION C

SCALE: 3/8" = 1'–0"

PETERSON POWER SYSTEMS INC.
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Solar Turbines
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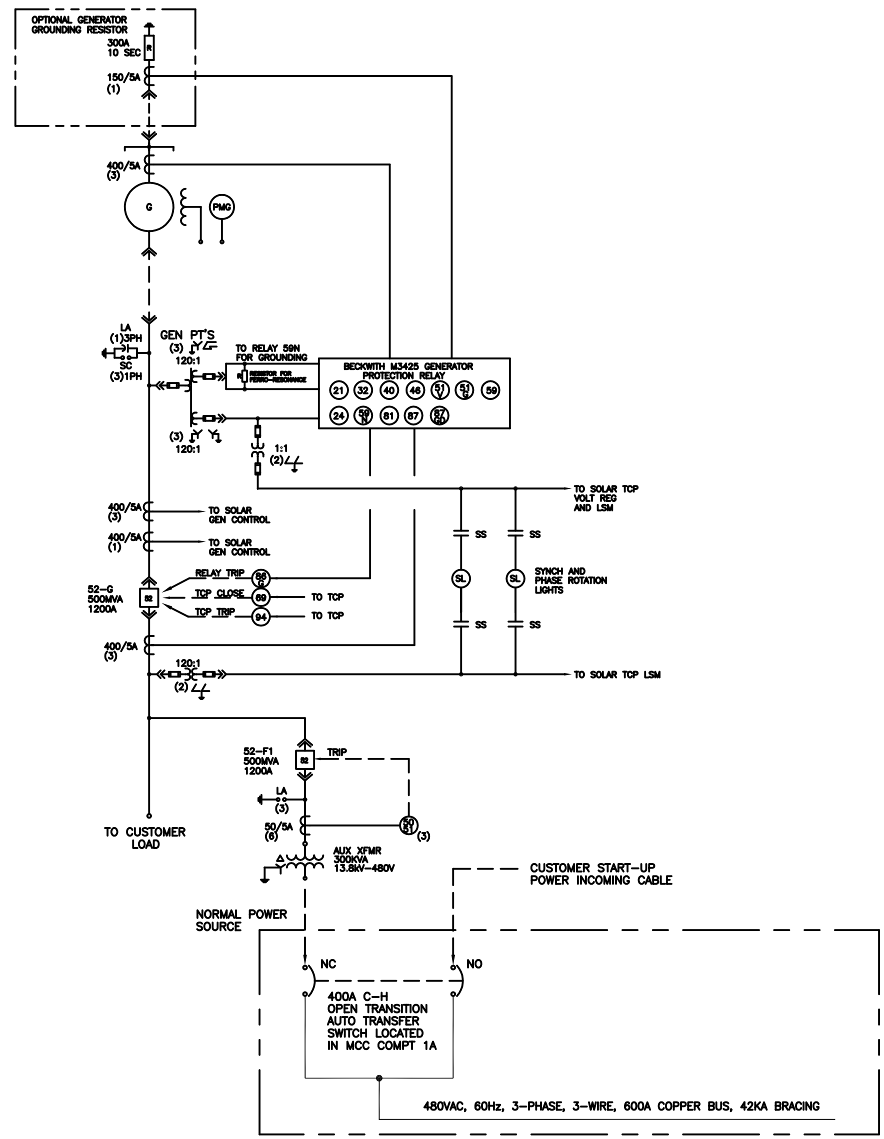
San Diego, California 92186–5376

DATA CONTROL LEVEL	RELEASE STAMP	CONTRACT NO.
DFTR. DFH	12–12–00	
CHKR. J PLESCIA	12–22–00	
LYT.		
MODEL LEVEL	ENGR. D F HAAS	12–12–00
LAYOUT	ME	
NHA	PLOT DATE	03–30–01
MODEL	PLOT SCALE	1=32
CADDS IDENT. 59731P001	CUSTOMER	

PIPING PLAN AND SECTIONS
TAURUS 60 – DUAL FUEL
MOBILE UNIT

SIZE	CAGE NO.	DWG. NO.
D		59731–1500–P001
SCALE: NOTED	TOTAL WT.	SHEET OF



REVISIONS

REV	DESCRIPTION	DATE	APPR'D
A	ISSUED FOR APPROVAL	10/30/00	MJR
0	ISSUED FOR CONSTRUCTION	11/14/00	MJR
1	AS-SHIPPED	5/3/01	MJR

REFERENCE DRAWINGS

NOTES

IPCS
APPROVED

PROJ ENG	DATE
DISCIPLINE ENG	DATE
CHECK	DATE
DESIGN/DRAFT	DATE
PROJECT ITEM NO.	
CUSTOMER IDENT. NO.	
CUSTOMER SOLAR	

SOLAR TURBINES–CAT PROJECT
MOBILE POWER TRAILER PROJECT
OVERALL ONELINE DIAGRAM

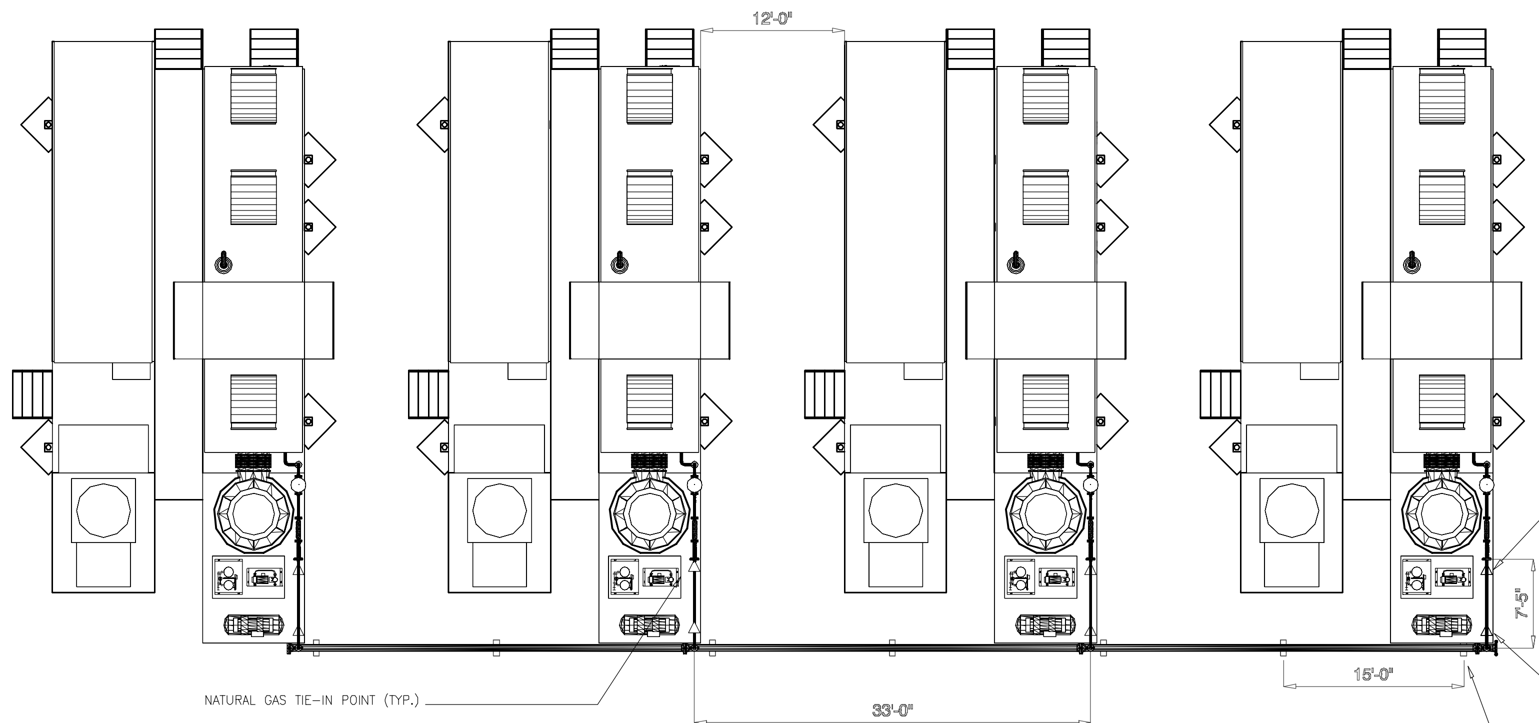
INDUSTRIAL POWER & CONTROL SYSTEMS
5535 HARVEY WILSON DRIVE HOUSTON, TX 77020

DRAWING NO. J20020–E001 | SCALE | REV. 1 | SHEET

PROJECT: CAT PROJECT FILE NAME:

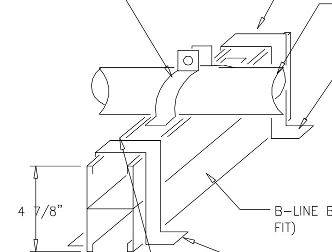
NOTES:

1. SEE M-402 FOR ISOMETRIC VIEW AND BILL OF MATERIALS.
2. SEE G-001 GENERAL NOTES FOR INSTALLATION.
3. GAS FUEL TO BE IN ACCORDANCE WITH SOLAR SPECIFICATION ES-9-98-F.
4. MAXIMUM FLOW DEMAND PER UNIT IS 1400 SCFM OR 5600 SCFM FOR 4 UNITS.
5. MINIMUM FUEL SYSTEM REQUIRED AT PACKAGE IS 250 PSIG AT AMBIENT TEMPERATURE OF 0°F.
6. SEE E-204 AND E-205 DRAWINGS FOR ELECTRICAL LAYOUT.



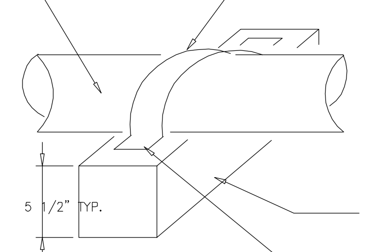
(4) UNIT XQ5200 PLAN

SCALE = 1/8" : 1'-0" - SF:96
0 1 2 4 8



1 PIPING SUPPORT DETAILS

8 ASSEMBLIES



2 PIPING SUPPORT DETAILS

7 ASSEMBLIES

PROGRESS PRINT
NOT FOR CONSTRUCTION

PETERSON POWER SYSTEMS
2718 TEAGARDEN STREET
SAN LEANDRO, CA 94577

CAT

PH: (800) 889-WRMS
Fax: (925) 933-5167
CRITICAL ENGINEERING
Walnut Creek, CA
Seattle, WA

Drawn By: FDA	XQ5200 STANDARD ARRANGEMENT 4 UNITS -20MW
Designed By: TH	
Date: 12.02.04	PLAN VIEW AND PIPE SUPPORT NATURAL GAS
Proj. No.: 04-284	One Inch at Full Scale 0 .5 1.0 / Dwg. No.: M-202 / Rev.: A

Rev.	Description	Date	Drawn By	Appr. By

PROACTIVE POWER . . . FAST

Cat dealer provides Canadian government a turnkey power project, including 115 MW of peaking power, in just six weeks.

The word impressive just doesn't seem to cut it when trying to describe Toromont Power Systems' latest mega power project.

The Cat dealer, with the help of Cat Rental Power and Peterson Power Systems, the Northern California Dealer responsible for world wide marketing of mobile turbines, provided 115 MW of peaking power to the Ontario Provincial Government. That in itself is an impressive job. But to install it and have it all online in a mere six weeks is phenomenal.

"The Ontario Independent Electricity Market Operator (IEMO) is the group that looks after the electrical system. They were forecasting a power shortage potential through summer and fall," explains Peter Ronson, account manager for Toromont. The province very nearly implemented rolling blackouts during the summer of 2002, so there was a lot of concern for the summer of 2003.

"We put the idea in front of the government that on short notice, they could bring in significant amounts of temporary generation to use during peak power periods," Ronson notes.

The government took Toromont up on their offer and sent out a request for proposal for 200 to 400 MW of peak generation. When all was said and done, out of the original seven companies awarded contracts for about 450 MW, only three companies came through for approximately 250 MW of natural-gas-fueled peaking power. Cat dealer Toromont was awarded the largest share at 115 MW. The contract gave the suppliers only six weeks to put all the capacity online.

TURNKEY FROM DAY ONE

"Our single biggest challenge was simply the logistics of the project," explains Ronson. "Because this was a turnkey project, we provided not only the generation (32 Cat power modules and turbines), but also all the distribution equipment, transformers, high-voltage disconnects, natural gas piping, valves, regulators, meters, etc., to complete the project. We were engineering, procuring, shipping, installing and commissioning all at the same time, while keeping our regular day-to-day business going.

"At the same time, Toromont was responsible for all emission and noise approvals, permits and contracts with land owners and utilities. "I spent much of my time trying to keep contracts and other needed paperwork from holding up our engineering and construction personnel, "exclaims Ronson.

But before any of that could even begin, appropriate sites for the equipment had to be identified. "Our customer wanted a complete turnkey project," explains Ronson. "That meant they looked to us to identify not only the equipment, but also where to hook it up as well ashow to hook it up — and then operate it for the duration of the contract. "Toromont identified three sites for the temporary generation:

1. Markham — This is the largest site and is located adjacent to a local utility-owned transformer station. The step-down transformer station has the capacity to house 100 additional MW. It also has a high-pressure natural-gas line (crucial as the government accepted only natural-gas-fueled generation). It's here that Toromont placed 19 Cat XQ5200 mobile power modules

powered by Solar Taurus 60 Turbines. (The 5.2 MW Turbines were made available by Peterson Power Systems.)

2. Bear Road Landfill — This site is an existing landfill gas power plant with four Cat G3516 engines and a natural-gas line for fuel blending. “It met our two biggest requirements — an electrical connection with existing parallel generation protection equipment and natural-gas connection point,” Ronson notes. Six XQ1250G power modules are located here. Each is powered by a Cat G3516B engine and is rated at 1,250 kW continuous.

3. Concord — This site is Toromont’s main head-office location. Seven XQ1250G power modules were installed here.

ADDRESSING THE CHALLENGES

Sheer numbers were the theme for this project. For example, at times, there were more than 100 people working at just one of the three installation sites.

Challenges were plentiful, but so were solutions. “Once we began construction, locating Cat generator sets and turbines was the easiest part, thanks to the Cat dealer network,” says Ronson. Especially with the help from Gene Hamilton, Mobile Turbine Specialist at Peterson Power Systems. “We were ready as soon as they called to work on the technical aspects of the proposal,” says Hamilton. “It is really great when the CATERPILLAR Network mobilizes to get the job done.” Sourcing materials was the most challenging and risky. Because most of the generation came from the United States, a difference in standard voltage had to be addressed. Cat XQ1250s run at 480 volts in the U.S., but in Canada the standard voltage at that level is 600 volts. The Solar Turbines generate at 13,800 volts in the U.S.; standard distribution level voltage in Ontario is 27, 600 volts.

“Finding enough step-up transformers became an issue. We ended up contracting out for custom-made, brand-new transformers,” says Ronson.

All brand-new cable and suitably sized high-voltage disconnects also had to be sourced. “Materials and logistics played a huge roll in this project,” he adds. “And coordination, teamwork and a lot of long hours and hard work were the key to it all.” The dealer had cooperation from contractors, the local electrical utilities, the gas company, as well as the Ontario Ministry of Environment (for air and noise emissions permits).

Toromont’s Electric Power Field Service staff took on the job of commissioning all the Cat XQ1250 packages, while a team of Solar Turbine technicians from Peterson Power Systems worked tirelessly at commissioning two turbines a day – a job that normally takes three days per turbine.

Remote start-up, shutdown and monitoring is handled by Point guard, a caterpillar affiliate company, and requires no site-staffed technician.

The province of Ontario peaks at around 26,000 MW. This project’s 115 MW may not seem like a drop in the bucket, but when energy is stretched, it could make a huge difference.

FOLLOWING THROUGH

With the sheer effort and determination of a lot of folks, the 115-MW Ontario project was completed on time. As of this writing, the last generator was brought online and successfully tested.

The contract details that the customer can call the dealer anytime weekdays between 7 a.m. and 11 p.m. to provide generation. Within 15 minutes, all 23 units must be online. “There are significant financial penalties if the generation doesn’t perform, ”explains Ronson.

To assure that penalties aren’t incurred, and to address the need to immediately and remotely start all of the equipment, Toromont turned to PointGuard, a Caterpillar affiliate company, to provide system monitoring and management solutions. PointGuard remotely starts, stops and monitors the generation.

Before they can bring the units to full load, the PointGuard staff has to obtain permission from the utilities. “It’s a tough job, but we’re confident they will perform it to a tee,” Ronson concludes.

The dealer will complete weekly testing and preventive maintenance with in-house field service staff. The rental is scheduled to continue until at least the end of the year.

The temporary generators have already proved themselves very useful during the August cascading blackout in cities across the Midwest and Northeast United States, as well as the Canadian province of Ontario.

“As soon as the power was restored to the main transformer stations where the generators are connected, we started them up and supplied power on a continuous 24/7 basis for several days until the nuclear power plants in Ontario could be brought back online,” Ronson says. “It was unfortunate that we could not provide emergency power immediately during the blackout, but the sites are simply not technically setup to do so. However, if the blackout had continued longer than 12 hours at our sites, we would have definitely made the needed changes to provide emergency power.

“Would you believe that the very same afternoon of the blackout, we were providing a tour of the sites to a number of the provincial government representatives, the IEMO, utility reps and others?” he reveals. “It just goes to show that proactive power planning really does pay off.”

IDEAL ELECTRIC CO.
330 EAST FIRST STREET • MANSFIELD, OHIO 44902 • USA
TELEPHONE (419) 522 - 3611 • FAX (419) 522 - 9386

GENERATOR DATA SHEET

EE - 3194

Manufacture Data

Model	SAB
Frame No.	21320-32

Generator Rating

KW	5300	KVA	6625	P.F.	0.8
Voltage (Line)	13800	(Phase)	7967		
Amps (Line)	277	(Phase)	277		
Phase	3	Poles	4	Connection	Wye
Hertz	60	RPM	1800	Pitch (P.U.)	0.788

Insulation Class F

Temperature Rise 80 °C (Stator by RTD)
80 °C (Field by Resistance)

Exciter Rating

KW	21	Volts	125	Amps	168

Field Resistance 16.3 Ohms at 25°C
Temperature Rise 80 °C (Armature)
80 °C (Field)

Excitation Requirements

Exciter Field	Volts	Amps
Generator No Load	22	1.1
Generator Full Load	66	3.3
320% Fault Current Forcing	200	10

PMA Rating

KVA	2.4	Volts	240	Amps	10
Hertz	120	Phase	1		

Temperature Rise 60 °C

Generator Operating Characteristics

Efficiency (%)

Load	0.80 P.F.	1.0 P.F.
100%	96.6	97.1
75%	96.4	96.8
50%	95.6	95.9
25%	92.8	92.9

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GENERATOR DATA SHEET

EE - 3194

Losses (KW)	Full Load	No Load
Core	46.1	46.1
Friction & Windage	47.1	47.1
Stray load	31.3	0.0
Stator I2R loss	40.5	0.0
Rotor I2R loss	17.4	2.4
Exciter	2.0	0.3
Total	184.3	96.0

Reactances (per unit at KVA rating)

		Saturated	Unsaturated
Direct Axis Synchronous	Xd	1.786	1.976
Direct Axis Transient	X'd	0.268	0.288
Direct Axis Subtransient	X"d	0.173	0.182
Quadrature Axis Synchronous	Xq	1.032	1.032
Quadrature Axis Transient	X'q	1.032	1.032
Quadrature Axis Subtransient	X"q	0.192	0.202
Negative Sequence	X2	0.187	0.192
Zero Sequence	Xo	0.067	0.071

Time Constants

Direct Axis O.C. Transient	T'do	5.540
Direct Axis S.C. Transient	T'd	0.751
Direct Axis O.C. Subtransient	T"do	0.050
Direct Axis S.C. Subtransient	T"d	0.032
Armature Short Circuit	Ta	0.082

Resistance at 25 °C

DC Armature	Ra	0.129	ohms
DC Field	Rf	0.891	ohms
Positive Sequence	R1	0.006	p.u.
Negative Sequence	R2	0.016	p.u.
Zero Sequence	Ro	0.007	p.u.

Short Circuit Ratio		SCR	0.560			
Inertia Constant (Generator Only)		H	0.893	kW-sec/kVA		
TIF (1960 weighting)	50	Balanced		40	Residual	
Waveform Deviation Factor	6%	at no load				
Harmonic Content	3.0%	Individual		3.0%	Total	
Allowable Negative Sequence Current	10%	Continuous		Short Time	K=	40
Guaranteed Noise Level (dBA at 1 meter)		110				

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GENERATOR DATA SHEET

EE - 3194

Initial Temperature Detector Settings	Alarm	Shutdown
Windings	120 °C	130 °C
Bearings	185 °F	190 °F

Heat Rejection at Rated Load (Btu / Hr)

Exterior Surfaces of Generator	1601
Generator Exhaust	627191

Transient Torques	Max. Torque (Lb-Ft)	(per unit)
3-Phase Short Circuit	182422	8.80
L-L Short Circuit	184841	8.92
3-Phase Out of Phase With an Infinite Bus	474298	22.89
1-Phase Out of Phase With an Infinite Bus	490918	23.69

L-L Short Circuit Torque Equation (per unit of rated torque) w = 377.0 radians / sec

6.09e(-13.6)t sin(wt- 0.16) -3.59e(- 2.7)t sin(2wt- 0.07) + 0.73e(-17.2)t

Short Circuit Current	RMS Symmetrical	Peak Asymmetrical
3-Phase	1.60 kA	4.53 kA
L-L	1.33 kA	3.77 kA
L-N	Limited by Neutral Grounding Device	

Voltage Dip Motor Starting (0.0 P.F.)	Voltage Dip	Inrush (SKVA)	Motor HP (Code F)
	10%	2747	490
	15%	4362	779
	20%	6180	1104
	25%	8240	1471
	30%	10594	1892

Step Loads (0.80 P.F.)	Applied Load	Applied Load (KVA)	Voltage Dip
	25%	1656	4.0%
	50%	3313	7.9%
	100%	6625	15.3%

Voltage Regulator System Recommendations

Manufacturer: Basler Electric Co. Model: SSR 125-12

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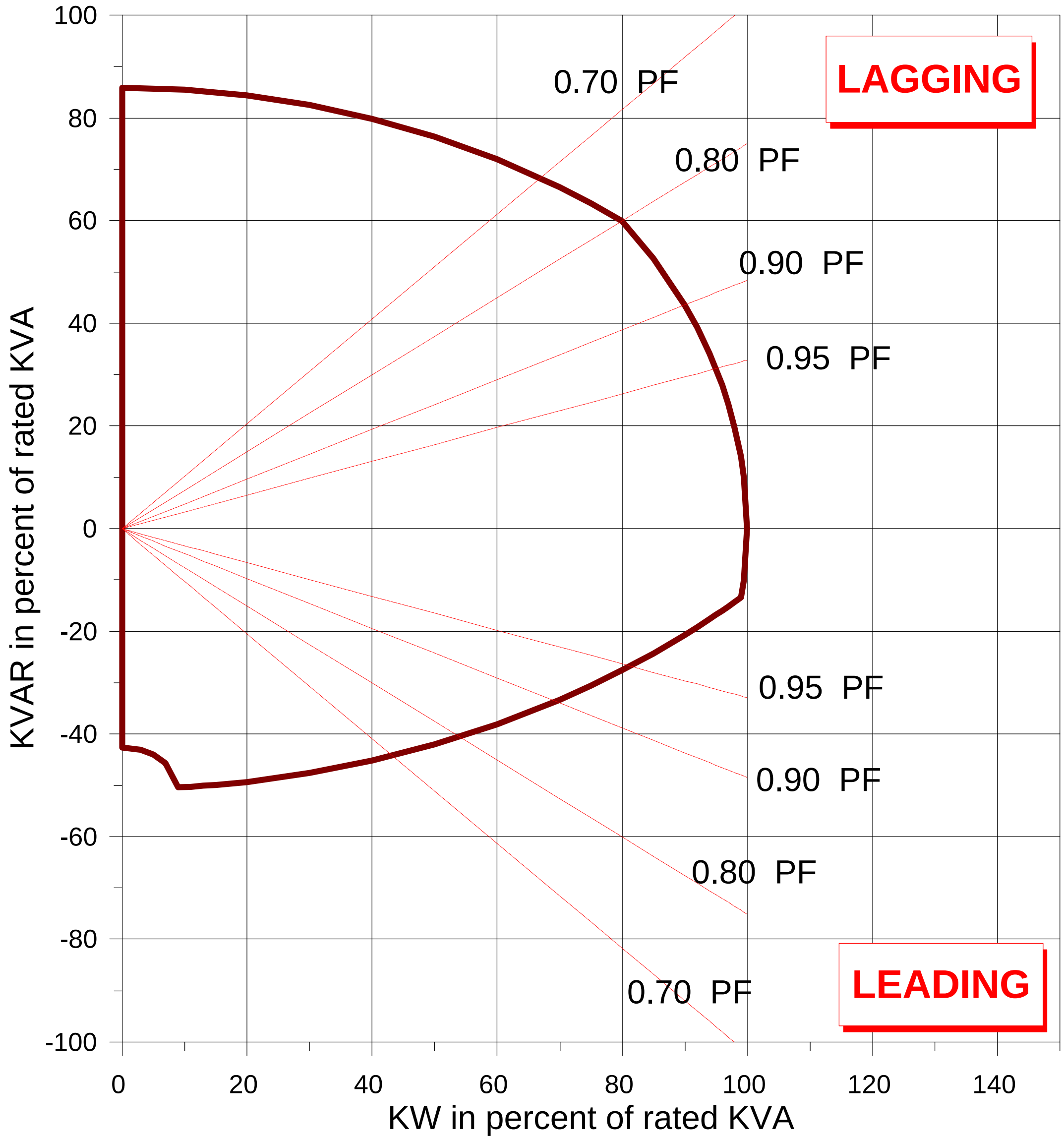
REACTIVE CAPABILITY CURVE



Rating:
6625 KVA
13800 Volts
277 Amps
0.80 P.F.
1800 RPM

Class B Temperature Rise

EE- 3194A

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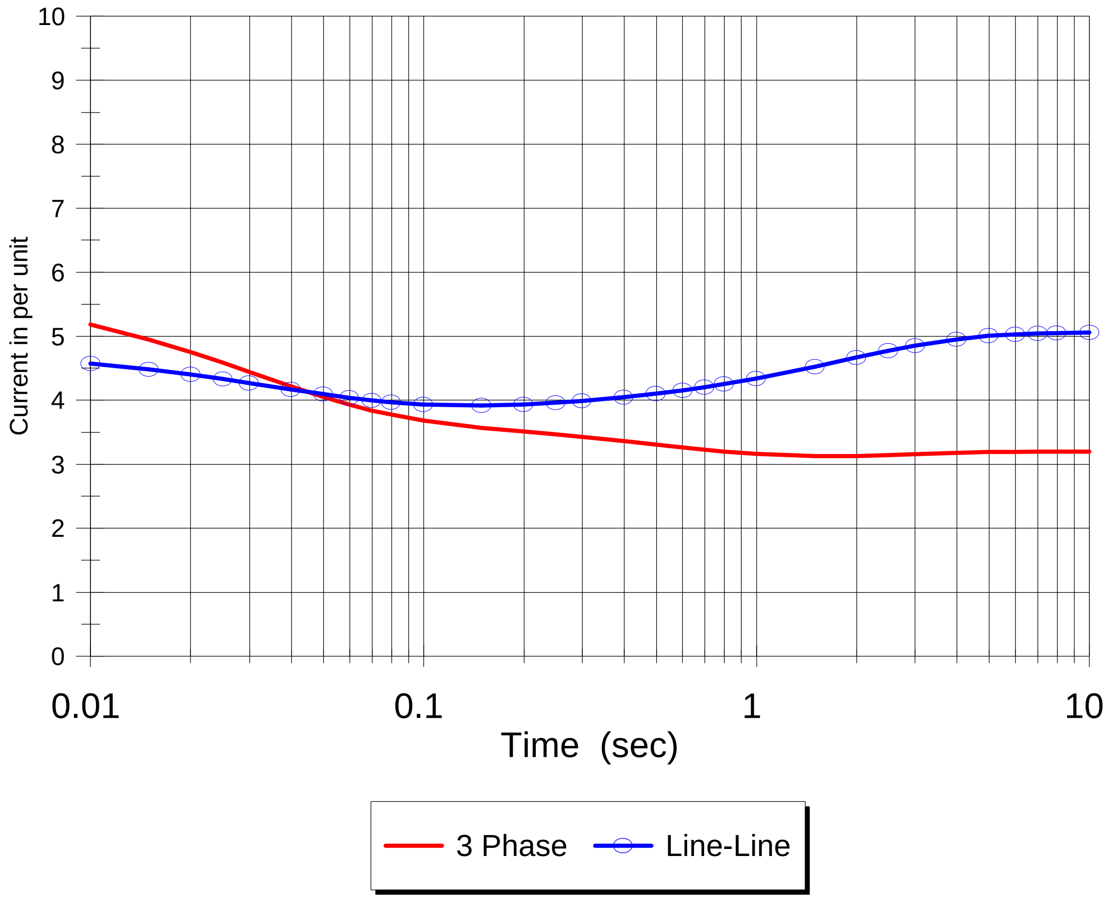
SHORT CIRCUIT DECREMENT CURVES



Rating:
6625 KVA
13800 Volts
277 Amps
0.80 P.F.
1800 RPM

Class B Temperature Rise

EE- 3194B

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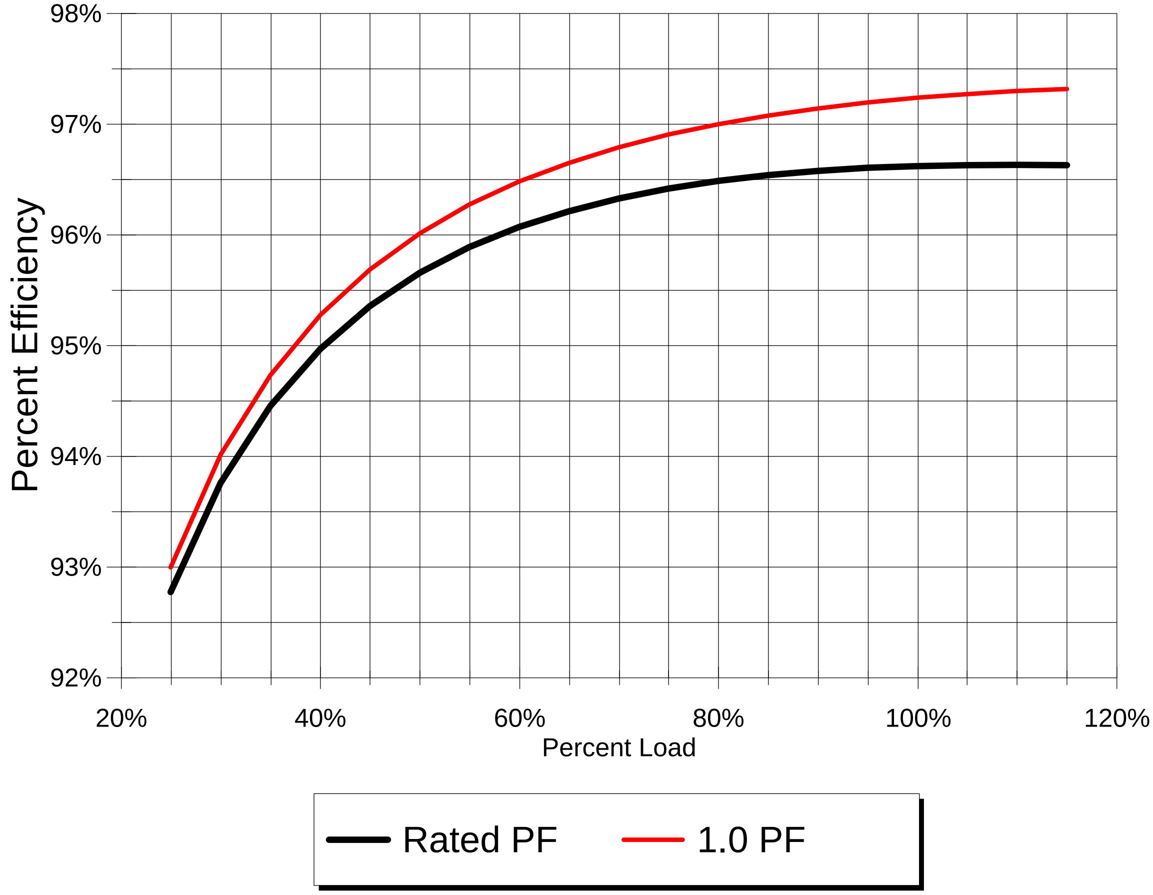
EFFICIENCY CURVES



100% Load = 5300 kW

Rating:
6625 KVA
13800 Volts
277 Amps
0.80 P.F.
1800 RPM

Class B Temperature Rise

EE- 3194C

Hearn, Bill G.

From: Hearn, Bill G.

Sent: December 12, 2007 9:58 AM

To: 'AndreaMacDonald@nlh.nl.ca'

Cc: King, Brian

Subject: FW: FT8 MobilePac

Andrea:

We received the following information (below) on the P&W FT8 MobilePac GT. While details need to be finalized, this is a start. Mr. Vecchiarelli noted that if Hydro has any interest in his offer, please let him know so he can firm up this offer. We will include words in the Final Report on the tentative P&W MobilePac offer and note that it is up to Hydro to contact P&W if you wish to pursue this matter. P&W has indicated the European customer requires the MobilePacs for winter operation only.

Bill

Bill Hearn, P. Eng
Senior Consultant -- Power
Stantec
#1 South 130 Eileen Stubbs Avenue
Dartmouth NS B3B 2C4
Ph: (902) 434-7331 Ext. 1371
Fx: (902) 462-1660
Bill.Hearn@stantec.com
www.stantec.com

-----Original Message-----
From: King, Brian
Sent: December 12, 2007 9:37 AM
To: Hearn, Bill G.
Subject: FW: FT8 MobilePac

Bill,
Here is the offer by Pratt and Whitney for a 25MW Rental Unit. I have added numbers to the text to show how much it would cost for a four month rental to match what we said for the Caterpiller offer. Note that this is in the same ball-park figure as for the Cat offer-- $3,152,000.

Brian

-----Original Message-----
From: Vecchiarelli, Philip [mailto:philip.vecchiarelli@pw.utc.com]
Sent: Wednesday, December 12, 2007 12:51 AM
To: brianking@stantec.com
Cc: King, Brian; Rooks, Debbie L.
Subject: FT8 MobilePac

Brian:
Sorry this late on Tuesday but it has been a long day with e-mail problems.
The units that we are looking at to lease are owned by a European customer.
The units would have to be transported to your site in Canada. This is a

quick estimate of what the costs would be for a lease. **The customer has seven units that may be available for lease in the summer months.** If you have any interest, please let us know so we can firm up this offer.

Transportation to site $625,000		$ 625,000
Monthly lease fee $400,000	4 Months	$1,600,000
Site set up fee $150,000 per site		$ 150,000
Site dismantle fee $150,000 per site		$ 150,000
Transportation back to Europe $625,000		$ 625,000
Full time site supervision per month $25,000.	4 Months	$ 100,000
HV Connection		$ 50,000
Fuel connection		$ 7,500
	TOTAL:	**$3,307,500**

Phil Vecchiarelli
Area Director
PWPS
860-565-7877

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FT8 Combined Cycle
FT8 MOBILEPAC
FT8 SWIFTPAC
IGT Parts & Repairs

MOBILEPAC™

The FT8 MOBILEPAC is 25 megawatts of power on wheels.

Pratt & Whitney Power Systems' newest product, the FT8 MOBILEPAC, is a self-contained, gas turbine powered electric generating unit using PWPS' efficient FT8 gas turbine. This new mobile package consists of two primary units - the power trailer and the control trailer. The power trailer contains the gas turbine and the electric generator, while the control trailer houses the electrical control unit.

The MOBILEPAC can be on the grid and operating within 8 hours. This type of power package, along with its relatively small size, allows the MOBILEPAC to be installed in almost any location and conveniently relocated or combined with other units to meet an area's emergency or temporary power needs.

Modular options can be added to allow long-term environmentally compatible operation. Just like the proven FT8, the MOBILEPAC can run on either gas or liquid fuel. Black start capability is another option with the MOBILEPAC.

MOBILEPAC SERVICES »

Contact Us

ENGINES WORK

NEW STANDARD FOR MOBILE GAS TURBINE POWER PACKAGES

Presenter: Brian Donnelly
Chief Engineer
Pratt & Whitney Power Systems,
80 Lamberton Road
Windsor, CT 06095

Introduction

There has been an increased need for large-scale transportable power to meet emergency, outage and climate driven requirements around the world. To address this need, engineers at Pratt & Whitney Power Systems set out to create a 25MW Mobile Power Plant readily transportable by air, sea, and land, easy to set up within a small footprint in potentially challenging environments, and environmentally compliant.

Design

The primary design goal was to provide a transportable power plant that required minimum setup time and high reliability. Four trailers contain all of the equipment needed to set up a MOBILEPAC plant. One of two operational trailers contains the FT8 gas turbine engine aligned and coupled to the generator. This power trailer includes the inlet plenum, exhaust collector and diffuser, and the engine and generator lube oil system. Figure 1 is a 3D model of the structure and assembly use for design and structural analysis.

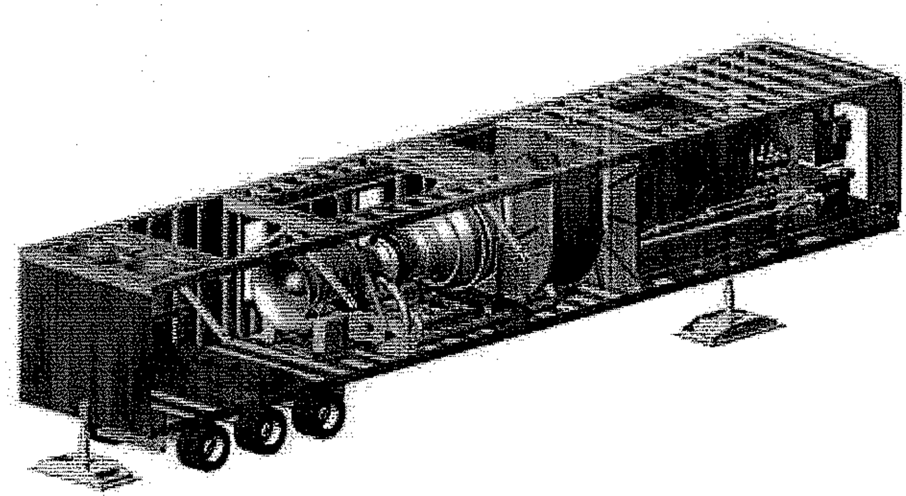


Figure 1: 3D Model of the MOBILEPAC

PWPS engineers designed a riveted aluminum monocoque structure for this power trailer. The structure is similar in construction to an aircraft hull in which the aluminum skin, riveted to stringers forms a strong yet lightweight container which reacts much like a reinforced cylinder to resist torsional, buckling and deflection loads. Basically, the skin of the trailer supports all of the static and dynamic loading of the gas turbine generator installation as opposed to reinforcing a conventional trailer with heavy channel and beam structures for strength. A 3-point support commonly used for installing gas turbine generator packages on offshore platforms and aboard ships is used. There is one outboard jacking and leveling plate located towards the rear of the trailer and two centered up front under the generator. Each of the three leveling plates sits on engineered fill compacted to 4000 lbs per square foot (or concrete pads at the option of the owner-operator) to support the trailer. The monocoque structure of the trailer acts as a solid plane to transfer its weight to the plates. Even if one leveling plate should sink, everything remains in plane so that the generator and turbine coupling alignment is not affected. The trailer is acoustically insulated to attenuate noise from the engine and generator. Figure 2 is a view of the power trailer under construction. Note the acoustical insulation. All electrical cables are brought to quick disconnect connectors on the enclosure wall. The picture is taken through the inlet as the plenum is not installed. The holes in the roof are for engine removal, exhaust and generator exhaust. The piping in the foreground is for engine lubrication oil.

The control trailer is built on a custom fabricated trailer. The control trailer includes a 15-kV circuit breaker, engine and station control system with monitor, protective relays and synch panel, batteries and charger, motor control center, PT auxiliary transformer and hydraulic start package and CO2 fire suppression. The control enclosure is heated and air conditioned to maintain a benign environment for the electronics.

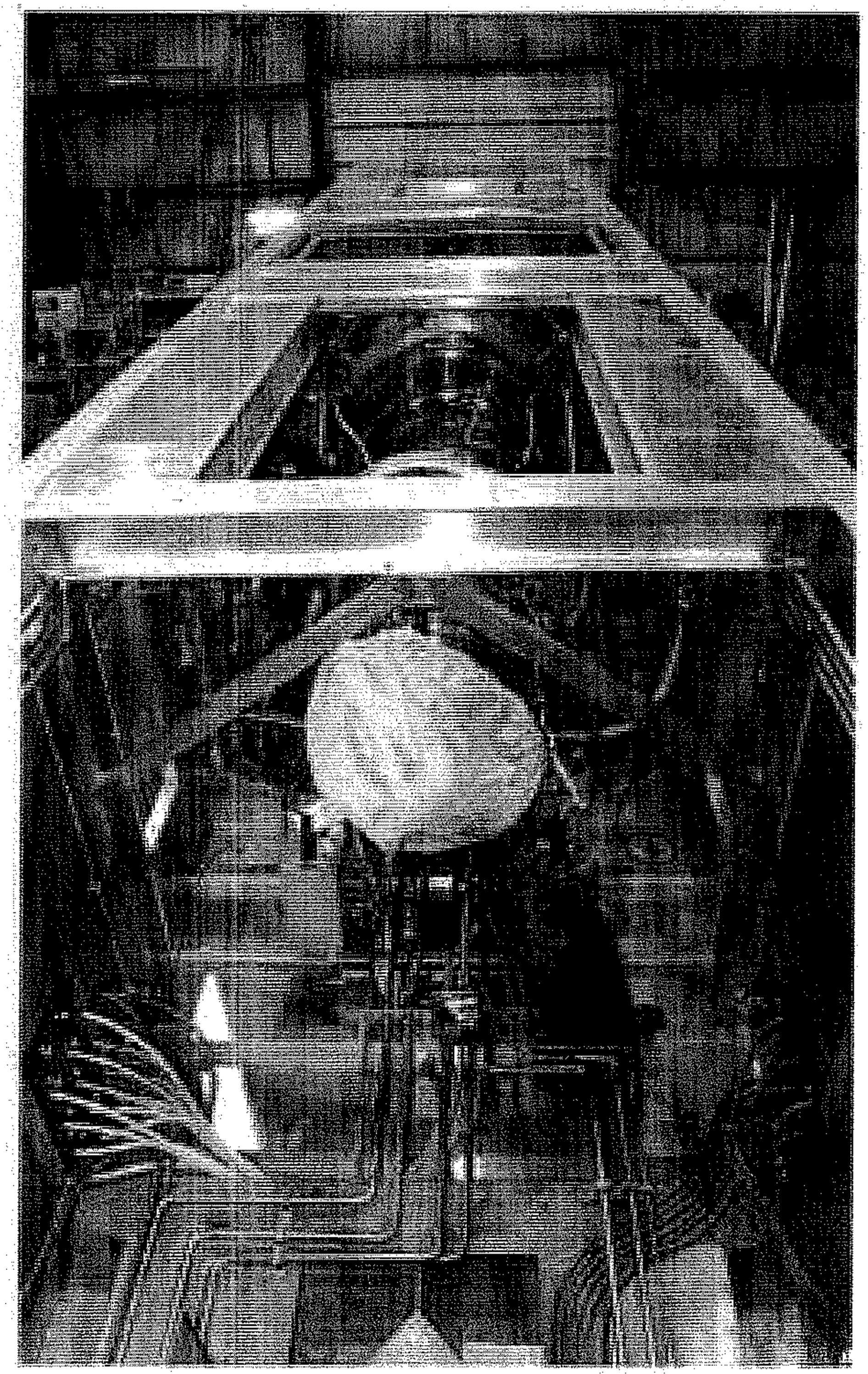


Figure 2: MOBILEPAC Power Trailer under construction

Transportation

The power trailer is transported to its site by a jeep and wheeled tractor that fits to a pivot pin under the front of the trailer. A hydraulically steered 3-axle bogey located towards the aft end of the power trailer facilitates negotiating difficult roads and to position the trailer on arrival at the site. The power trailer suspension is equipped with an air ride system to absorb road shock. The suspension has pneumatic jacking to adjust for road clearance. This trailer is approximately 65 ft long by 12 ft wide and 13.5 ft high. Adequate clearance was designed on the underside of the trailer for highly crowned or undulating roads.

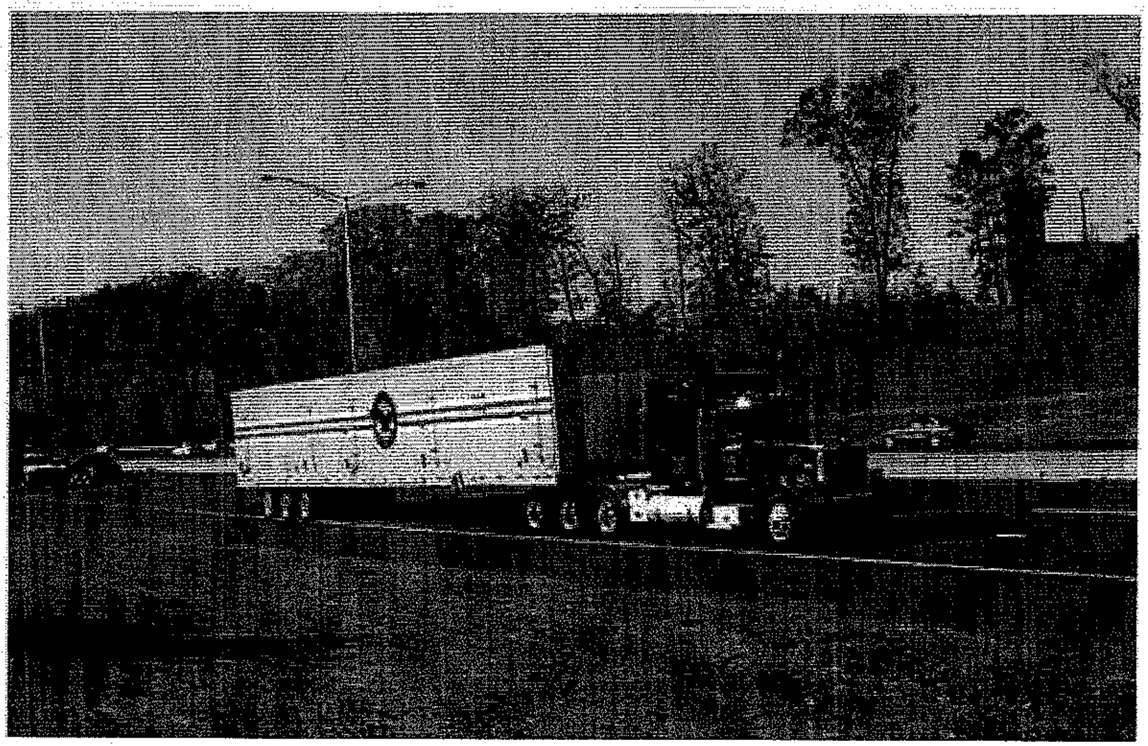


Figure 3: MOBILEPAC Power Trailer in transit on the Interstate.

The control trailer is about 50 feet long by 11.5 feet wide by 13.5 feet high. The control trailer suspension is also equipped with an air ride system to absorb road shock.

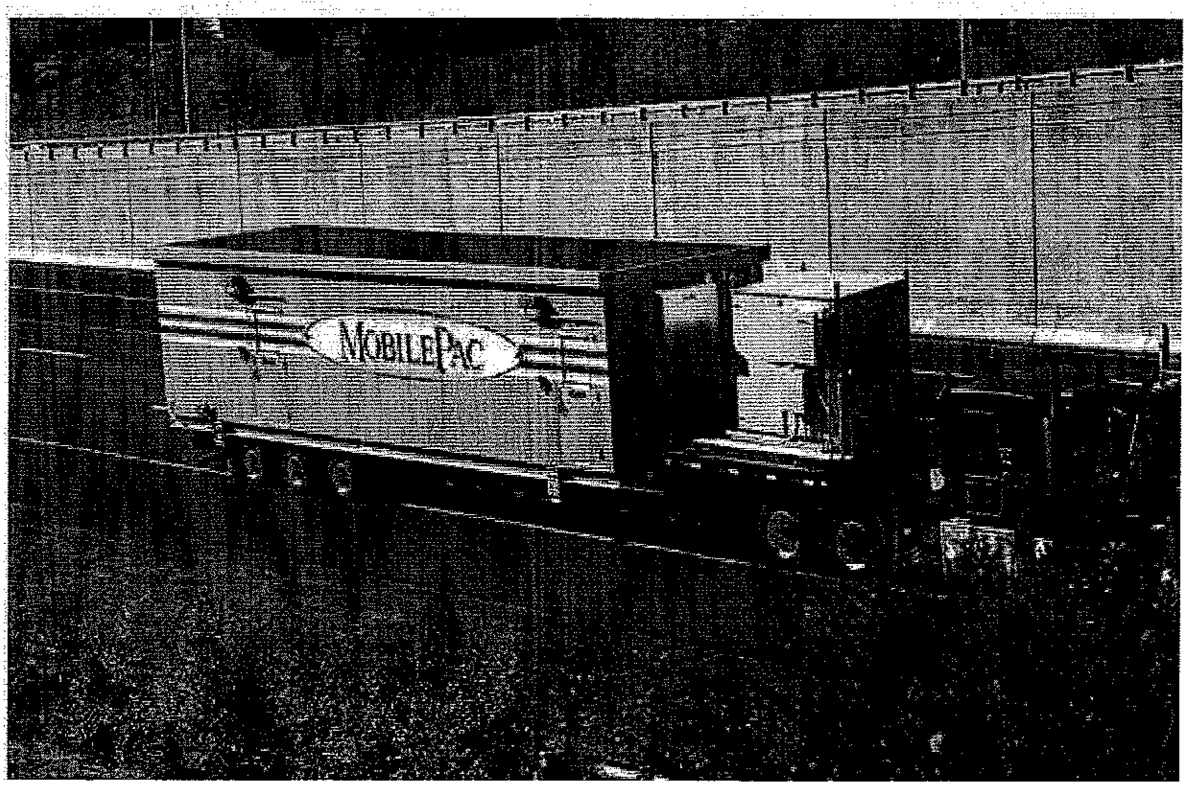


Figure 4: MOBILEPAC Control Trailer on the Interstate

Two standard trailers are used to deliver accessory equipment. One trailer carries three gas turbine exhaust stack sections, inlet air filter, and inlet silencer. The second one carries two exhaust silencers and, if specified as an option, water injection skid for NOx control. Each trailer is about 48 ft long by 11.8 ft wide by 13.5 ft high.

MOBILEPAC Installation

Depending upon site preference, the controls trailer can be set on the ground in line with the power trailer or parallel to it. In either case, the switchgear is positioned close to the generator. Little is required in the way of advanced site preparation to support the power and control trailers. There are no pilings or concrete pads required. The basics required are a mobile crane, site electrical power, a relatively flat surface and, for the power trailer, compacted soil areas for supports.

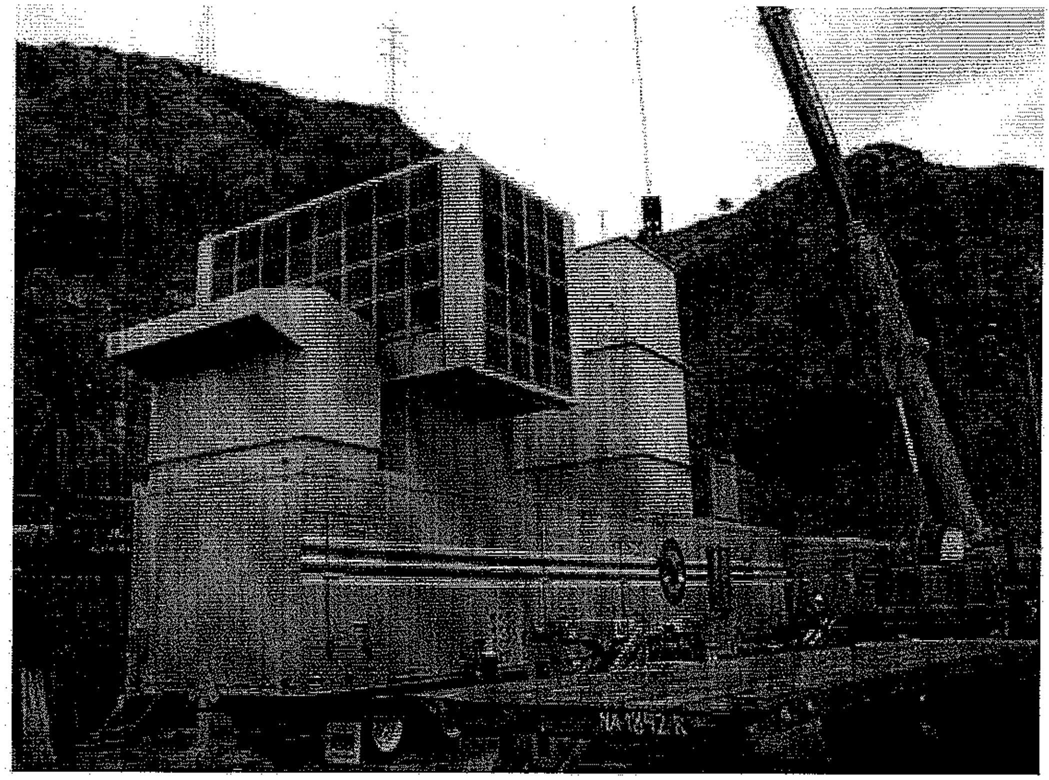


Figure 5: Assembly of Power Trailer, Control Trailer in the backround.

Upon arrival, air bags at the front and rear undersides of the power trailer are inflated to lift the trailer and take up the load, the jeep is unhitched and removed, and the trailer leveled using the jack plates. After the jacks are set and locked, the air bags are deflated. Electrical preparations include plugging in quick disconnect cables to mate with the already checked out turbine and plant control electrical signal systems. Mechanical preparation includes removing the shipping closures, connecting the cold air buffer, fuel and hydraulic start piping and hoses. Given a true emergency, the MOBILEPAC is ready to run without adding filtration or silencing. Therefore full power output could be supplied to the grid in 8 hours. A normal timetable includes installing exhaust stack sections (using crane supplied by operator-owner), exhaust silencers, and gas turbine inlet air filter and silencer – all of which go on top of the power trailer. Both accessory trailers remains on site just long enough to deliver (or pick up) the accessory equipment. This installation requires another 12 hours for mechanical and electrical preparations plus pre-operational system checkout by a 4-man crew working two 8-hr shifts.

All the plant requires to become operational is a fuel supply and a power connection to the grid.

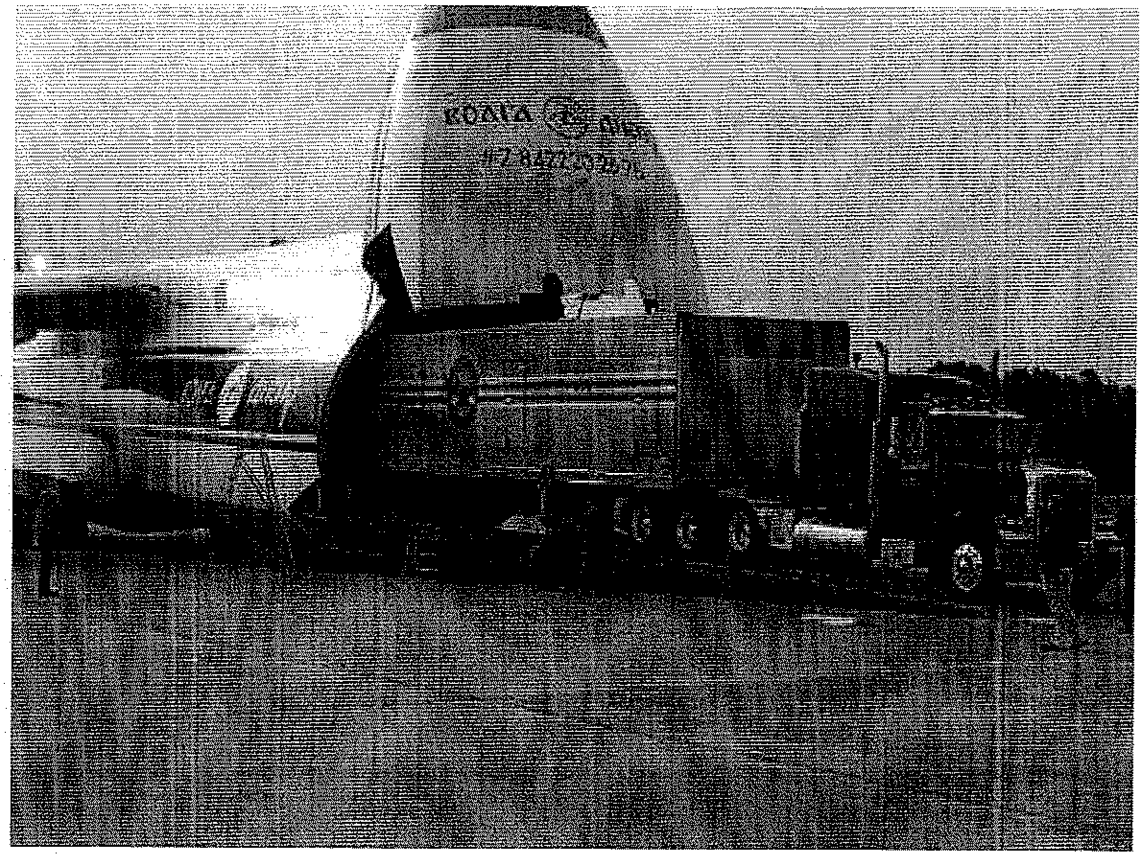


Figure 6: Trailers are designed for Air Shipment

First Site

The first installation of an FT8 MOBILEPAC was on La Palma in the Canary Islands. Since there was a need for power in the area and the island is somewhat remote, a MOBILEPAC was flown on a single plane, to an adjacent island and ferried to its final destination. Therefore transportation to this site verified that the MOBILEPAC is readily transportable by land, sea and air. The customer supplied truck mounted high side transformer and switchgear. Thus, a complete 25MW power plant is readily transportable. The only available site was on the side of a hill, on a terraced area, against a stone wall. The flexibility and relatively small size of the MOBILEPAC made this site a true success.

Maintenance

There is plenty of room around the gas turbine engine to carry out routine inspection and maintenance procedures. Access and working room inside the power trailer is the same as inside a stationary FT8 enclosure. For instance, there is full access around the combustors to inspect and replace fuel nozzles, cans and transition pieces (as required) without first having to remove other hardware that might be in the way. For removal or installation, it is necessary to disconnect and move the gas generator away from the power turbine so that it can be hoisted out the removable roof of the trailer. If it is ever required to remove the generator, the end wall of the trailer is removable.

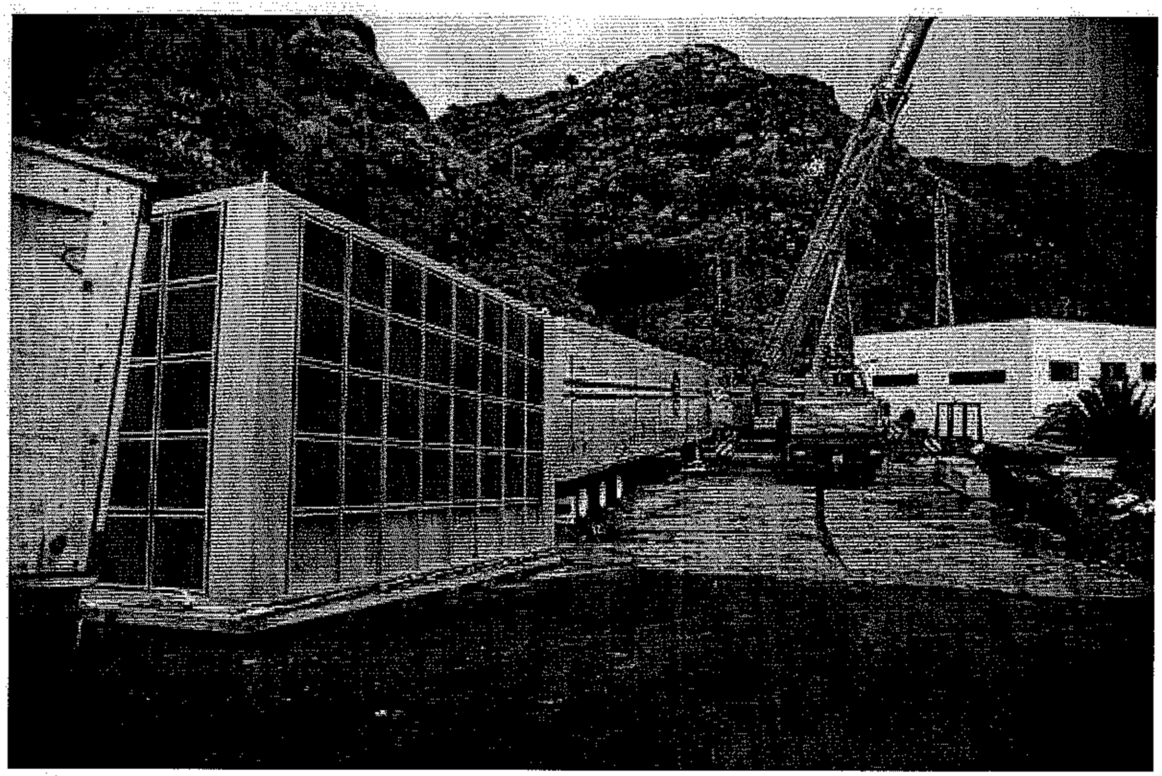


Figure 7: Mobile Site in the Canary Islands

Other Features

A MOBILEPAC can generate passive revenue by qualifying as "spinning reserve" or operate as a synchronous condenser when not needed for emergency back-up or peaking. It does not require a clutch to operate as a synchronous condenser due to its free power turbine. In the synchronous condenser mode of operation the plant can switch over to generate full 25 MW power output within 1 minute.

Should an emergency occur, a MOBILEPAC can be operated without filters and silencers. When time permits these components can be added later. Another potential advantage is the MOBILEPAC is not taxed as a permanent structure.

Summary

The new Pratt & Whitney MOBILEPAC incorporates several new design concepts resulting in the most flexible and highest performing mobile power plant on the market. Improved design concepts for trailer design, equipment alignment, and leveling technology, create a package that lowers costs to the customer and allows emergency installation in as few as 8 hours at a wide range of sites.

GAS TURBINE ON WHEELS

Caterpillar helps ensure stable energy supply during Western U.S. power crisis with new XQ5200 mobile turbine rental units powered by Solar Taurus™ 60 gas turbines.

The recent power crisis in the Northwest region of the United States still has everyone, especially power producers, thinking about ways to reduce the demand on the electricity grid while continuing to provide adequate, quality power to consumers. Customers are responding by looking for alternatives to utility power from the grid due to concerns over power reliability and price volatility.

Caterpillar has taken a lead role during this power crunch by providing quality temporary power to customers in all areas of the U.S. Recently, the Caterpillar network expanded its temporary power alternatives by adding Taurus™ 60 Mobile Turbine Power Units. The units are manufactured by Solar Turbines Inc. (a Caterpillar company) and are being debuted in the Cat Rental Power fleet.

Designated the XQ5200 based on its ISO rating of 5,200 kW, these new industrial gas turbine power modules are portable, low-cost power alternatives incorporating Solar Taurus 60 gas turbine generator set packages and prefabricated power control room modules.

The increased electrical power prices in the Northwest, as well as the challenges associated with bringing a complete power plant online quickly, are two important reasons the XQ5200 is playing an important role in meeting peak seasonal and emergency power demands, according to Steve Garceau, Caterpillar rental power manager.

"Plans to build additional U.S. power stations are in the works," he notes, "but Northwest customers need power now." The XQ5200 provides that necessary power, quickly and cleanly.

MOBILE POWER PLANTS

The new gas turbine power module is similar to traditional Caterpillar diesel power modules in its mobility. The trailer-mounted system is highway transportable and requires no concrete foundation, allowing it to be easily redeployed to other sites as needed.

This Cat XQ5200 Mobile Power Unit incorporates gas turbine technology to provide an environmentally friendly power source that can be easily deployed and permitted.

Quick setup is accomplished with a modular design including plug-in connections. The XQ5200 is dispatchable to be online in six minutes from cold start, which makes it ideal for utility rental applications.

The compact footprint of this turbine power module is a perfect fit for minimum space requirements common at substations and industrial customer sites. "Each XQ5200 is designed for less than 350 square feet per MW," confirms Dave Dunlevy, power generation manager for Solar Turbines.

At the core of the unit is the proven 5.2 MW Taurus 60 industrial gas turbine. The turbine is rated at 5,200 kW with a heat rate of 11,263 Btu/kW per hour. It has a proven history all over the world in more than 900 applications, from cogeneration and base load to distributed generation and standby.

Utility-grade switchgear and a programmable protective relay module are standard. A range of control system options for remote operation and Supervisory Control and Data Acquisition System (SCADA) compatibility are also available.

POLLUTION PREVENTION

Meeting peak seasonal or emergency power demands with an XQ5200 is also an environmentally friendly alternative. Each gas turbine power module can be configured for natural gas, diesel fuel or dual fuel operation. (Dunlevy notes that the turbines are typically most economical when natural gas is the primary fuel.)

The system also utilizes a dry low emissions combustion system (SoLoNO$_x$™) for low emission levels. This type of system uses a lean premix combustion system, as opposed to water injection, to control emissions. Water injection, notes Dunlevy, can be costly for the operator as well as a logistical burden for the site.

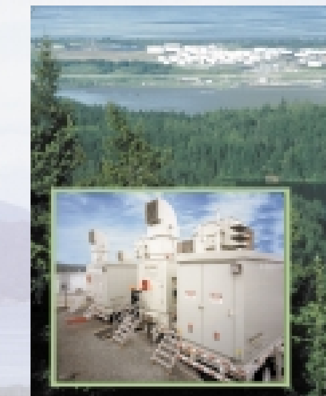
Further environmental features include a low-profile design that minimizes installed height and meets most permitting requirements, and a sound-attenuated enclosure for quiet operation.

DEALER NETWORK SUPPORT

Each XQ5200 is fully supported by the worldwide network of Cat Rental Power dealers. The network maintains the largest, most comprehensive rental fleet in the industry with more than 6,000 MW of power generation capacity, 50,000 tons of temperature control capacity, and a complete line of oil-free and oil-flooded air compressors and ancillary equipment.

For information on the XQ5200, contact Cat Rental Power at 800-RENT-CAT or visit www.CAT-rental.com. ■

Washington refinery relies on Caterpillar XQ5200 rental units



The first customer to take advantage of the Cat XQ5200 Mobile Power Units is Equilon Enterprises LLC. The company is one of the Top 10 largest oil refineries in the United States. It is a joint venture between Shell Oil Company and Texaco Inc. and consists of four refineries that produce a combined capacity of 480,000 barrels of oil a day.

Equilon engineer Bill Tezak recently called on Cat rental dealers N C Power Systems (Tukwila, Wash.) and Peterson Power Systems (San Leandro, Calif.) for a short-term source of on-site power generation at the company's Puget Sound Refining Company (PSRC) in Anacortes, Wash.

"Peak wholesale power prices in Washington state spurred Equilon to look to other power alternatives," explains Gene Hamilton, sales engineer with Peterson Power.

"As an oil refinery, we need consistent power all the time," notes Tezak. "It became cost prohibitive for us to purchase all our power from the grid."

Working in conjunction with N C Power, Peterson Power responded to Equilon's temporary power needs with four Cat XQ5200 Mobile Power Units. The units provide 21 MW of electrical power for the refinery – approximately 60 percent of the refinery's total electrical load.

The four turbines are contracted for one year with an option to extend the rental. "These turbines are part of our solution for this year," says Tezak. "We don't know what's going to happen with the power market in the future and we want to be prepared."

Currently, the refinery is running the units continuously. Tezak plans to continue this operation schedule as long as it is economical.

THE BENEFITS OF GAS

Gas turbines were a natural choice for the refinery, says Tezak, because of quick setup time and low emission levels. Fuel cost savings were also a key factor in the decision to use natural gas turbines.

"The modules have performed flawlessly," notes Hamilton, "with no unscheduled downtime during the first four months of operation." Scheduled maintenance is conducted every three months, and no full-time operator is needed to monitor the units due to the high reliability of the modules. Remote starting and monitoring functions are controlled inside the refinery.

Overall, Tezak is very happy with the XQ5200s as well as the Cat dealers who support them. "Peterson Power is an extremely helpful dealer," he reveals. "They've dealt with every problem and they've always gone beyond what they needed to do."

APPENDIX 10
DYNAMIC VAR COMPENSATION INFORMATION

APPENDIX 10
DYNAMIC VAR COMPENSATION INFORMATION

American Superconductor
REVOLUTIONIZING THE WAY THE WORLD USES ELECTRICITY

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Transmission Grid Solutions

D-VAR® Solutions - Dynamic VAR Support for a More Reliable Grid

D-VAR® (Dynamic VAR) STATCOMS provide a powerful and cost-effective source of dynamic VARs for a wide range of operational needs. D-VAR systems utilize a proprietary and advanced control and monitoring system that detects and instantaneously compensates for voltage disturbances by injecting leading or lagging reactive power. At the heart of each D-VAR system are American Superconductor's (AMSC) PowerModule™ advanced power electronic converters. PowerModule inverters are an intelligent, fully integrated four-quadrant power converter with high power density. D-VAR STATCOMS can respond to voltage events that are both rapid and slow, providing the same level of security, reliability, and enhancement to the grid as an SVC. >>More information on AMSC D-VAR systems

AMSC D-VAR® (Dynamic VAR) reactive compensation systems provide a powerful and cost-effective source of dynamic VARs for a wide range of operational needs. They can correct voltage instability problems on transmission networks; provide dynamic steady-state voltage and power factor control and regulation on transmission and distribution networks; protect industrial facilities requiring premium power quality; and support a stable point of interconnection for distributed generation facilities and large-scale wind farms. Classified as Flexible AC Transmission System (FACTS) devices, D-VAR systems utilize an AMSC proprietary and advanced control and monitoring system that detects and instantaneously compensates for voltage disturbances by injecting leading or lagging reactive power, measured in VARs (volt amperes – reactive), precisely where it is needed on the grid. D-VAR systems are extremely flexible and scalable, ranging from 2 MVAR to hundreds of MVAR.

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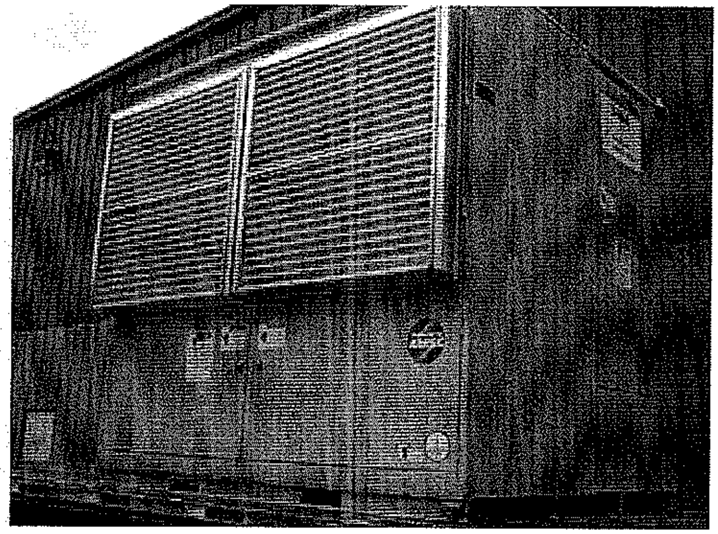
For more infor regarding our t grid solutions, contact us at: pesinfo@amsı



D-VAR systems are highly scalable and mobile solutions that allow utilities to install them in their power grid at locations that need the greatest amount of VAR support.

At the heart of each D-VAR system are American Superconductor's (AMSC) PowerModule™ advanced power electronic converters. PowerModule inverters are an intelligent, fully integrated four-quadrant power converter with high power density. The D-VAR is composed of rack-able IGBT power module poles capable of producing capacitive and inductive VARs. It is an air cooled, current source system that, unlike capacitor-based systems, is not subject to the square of voltage de-rating factor at lower voltages. This advantage reduces the overall level of MVARs needed for some applications. The inverters also have a short term overload capability of 2.67-3.0x of the continuous rating for up to 2 seconds, providing extra capacity for post-fault voltage recovery.

D-VAR Solutions Address Many Needs

AMSC's D-VAR system was designed with flexibility in mind to address the many voltage and VAR related problems seen on the transmission grid. More AMSC D-VAR systems have been installed throughout the world than any other inverter-based (STATCOM) reactive compensation device. Applications to date include:

- Localized Voltage Collapse Problems
- Single Point, Large Block, Transmission Connected Solutions
- Increasing Power Transfer Through Stability Limited Systems
- Reducing and Retiring RMR Generation for Voltage Support
- Wind Farm Voltage Regulation/ Low Voltage Ride Through
- Voltage Regulation on Radial Lines, and in Weak Grids
- Mitigating Industrial Voltage Transients

Benefits and Advantages of D-VAR Systems

AMSC's D-VAR systems enjoy unparalleled success in the field for many reasons. Strong and continuing customer relationships, along with proven, reliable technology, have made AMSC an industry leader, providing cost effective solutions that will work when it counts the most. When deciding on what solutions are appropriate, consider some of the benefits and advantages of D-VAR reactive compensation systems:

- High density, advanced power converters
- Low cost, easily permitted solution
- Can be deployed as a single, large block solution or distributed around an area
- World leader in Statcom installations and experience
- Minimal footprint and easy to install, leading to lower turn-key costs
- Overload capability helps maximize performance
- Minimal preventative maintenance required
- Completely air-cooled
- Fault tolerant and robust design
- Modular, relocatable and easily expandable to meet future requirements
- High field availability

Let our System Planning Engineers Help You

AMSC's transmission planning team is highly experienced, and works closely with customers to develop optimized, cost effective solutions to improve their system reliability. Former utility network planners themselves, they understand your specific needs and your network's operating behavior. They model its characteristics in accurate detail to determine the system response and offer customized solutions to meet your particular requirements. Some of the services provided include:

- Load flow studies
- Dynamic stability analysis
- Transfer capability studies
- Power quality and reliability studies
- Harmonic analysis
- System impact studies

AMSC's team of network planners uses industry standard software. They will work with you to find a solution in any modeling software that you may use. Some of the software utilized by our team includes:

- PSS/E
- PSLF
- PSCAD
- PowerWorld

At AMSC we won't just sell you a product, but rather a complete and integrated solution. All of our systems include detailed application engineering analysis and associated simulations validating the performance of our equipment on your grid. This enables us to insure our recommended solution is accurate and efficient and catered specifically to your needs.

Click here for more information on D-VAR reactive compensation systems, or to request a transmission planning study.

American Superconductor™

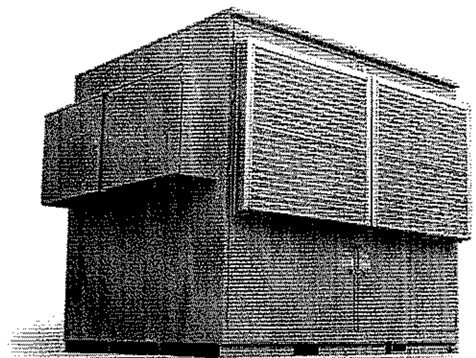
REVOLUTIONIZING THE WAY THE WORLD USES ELECTRICITY™

Benefits

- Provides steady-state voltage regulation
- Delivers superior transient response
- Improves grid reliability by stabilizing voltage
- Generates/absorbs VARs dynamically
- Modular construction enables quick deployment and future flexibility
- More compact and less costly to install than competing devices
- Highly efficient resulting in lower operating costs than other devices

Dynamic Reactive Power Compensation

Utilizing State of the Art Power Electronics Technology



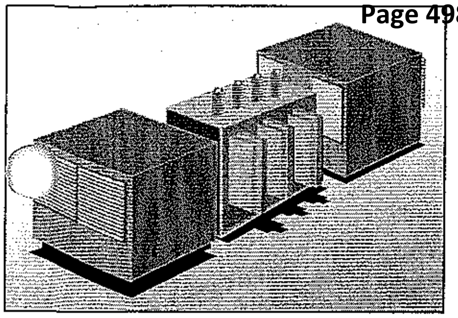
D-VAR systems are highly scalable and mobile solutions that allow utilities to install them in their power grid at locations that need the greatest amount of VAR support.

The American Superconductor (AMSC) dynamic VAR (Volt Ampere Reactive) system is a powerful, cost-effective solution that dynamically stabilizes and regulates voltage on power transmission grids and industrial operations. Utilizing AMSC's proprietary PowerModule™ power electronic converters, D-VAR® systems detect and instantaneously compensate for voltage disturbances by injecting leading or lagging reactive power at key points on transmission and distribution grids. Each D-VAR solution is customized to meet specific customer needs and includes inherent flexibility to accommodate changing grid conditions.

Transfer capacity of a power grid is often limited due to voltage instability. D-VAR systems provide a proven solution to address voltage stability issues and relieve associated constraints. D-VAR systems can be a valuable tool in increasing the power transfer capacity of the grid.

D-VAR systems allow wind farms to meet utility interconnection requirements including low voltage ride through (LVRT), voltage regulation and power factor correction. D-VAR systems can also mitigate transient voltage events and "soft switch" capacitors which extends the life of wind turbine gearboxes, switches and other components.

AMSC's transmission planning team has over 75 years of experience in transmission and distribution planning. This team will help you analyze your system by performing studies for low voltage, voltage stability, transfer capability and power quality problems. They will help you develop the least costly, most effective solution to alleviate your short and long term problems.



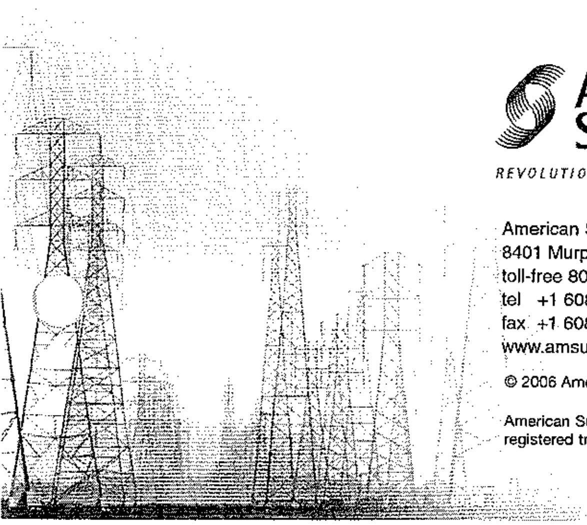
Example of an 8 MVAR D-VAR system which is 30 feet long by 11 feet wide. D-VAR systems are modular and compact and accommodate areas with restricted space availability.

Specifications

Connection:	Medium Voltage (up to 46 kV)
Frequency:	50 or 60 Hz
Continuous Rating:	±2.0 to 100s of MVARs
Transient Overload Rating:	2.67 time continuous for up to 2 seconds (application-specific)
Response Time:	Sub-cycle
Inverter:	IGBT, 4 quadrant, stacked units, 4 kHz switching frequency, rated at 1 MVAR, continuous duty
Output:	Independent phase control
Harmonics:	Per IEEE 519
System Monitoring:	Digital recording of system action, multiple inputs, alarms and warning signals
Ambient Temperature:	-50°C to +50°C
Other:	Mobile configuration for quick deployment Minimal on-site installation Compact installation for minimal footprint Remote monitoring Environmentally benign Ambient air cooling Current source not subject to square of voltage de-rating factor at lower voltages as in other systems based solely on capacitors

Product Applications

Reactive Compensation	Transmission and Distribution Systems
Steady State Voltage Regulation	Long Radial Delivery Systems, Wind Farms
Increasing Grid Capacity	Transmission Systems
Reduce Reliability Must Run Generation	Transmission and Distribution Systems
Voltage Sag Mitigation	Large Industrial Facilities, Wind Farms



American Superconductor™

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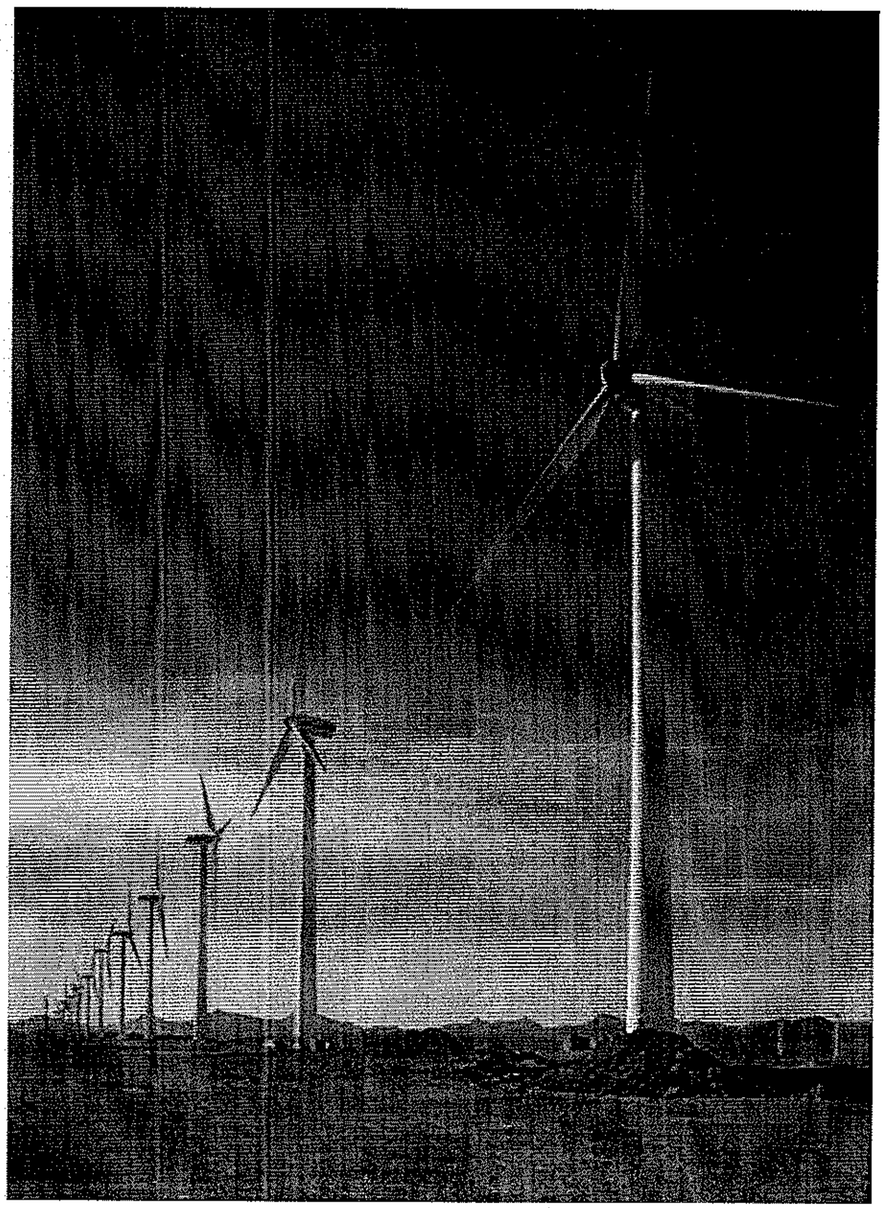
Optimizing Reactive Compensation for Wind Farms: Meeting Today's Utility and Regulatory Requirements

A White Paper by American Superconductor Corporation



How Dynamic VAR Technology Enables Wind Farms to Meet Grid Interconnection Requirements

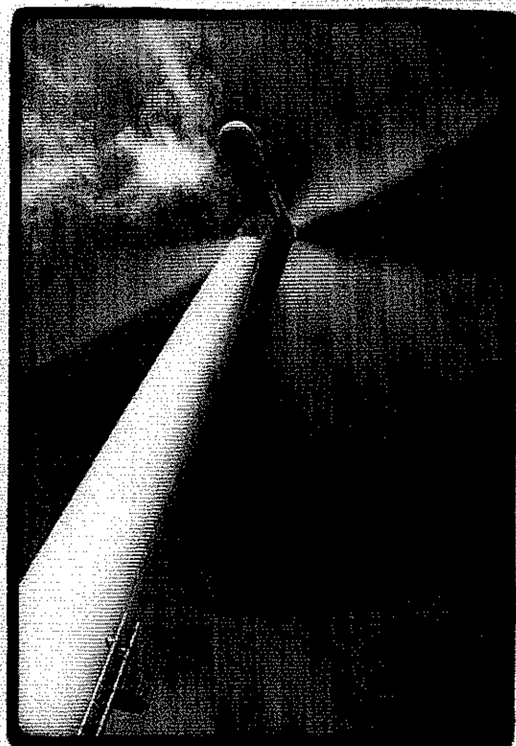
Executive Summary

Wind energy is one of the fastest-growing sources of electricity in the United States and around the world. The growing importance of wind power has subjected it to greater scrutiny and more rigorous operational standards than ever before. As wind-generated power transitions from boutique status to a full-fledged power source, it has become apparent that the industry needs smarter and more appropriate solutions to address common voltage regulation and dynamic voltage stability-related interconnection requirements.

Advances in dynamic volt ampere reactive (VAR) technology, coupled with innovative applications and services, eliminate the drawbacks of traditional voltage and power factor control methods and enable wind developers to meet today's more stringent and specific interconnection requirements. This white paper explores the background issues, available solution alternatives, including the installation of a dynamic reactive compensation system manufactured by American Superconductor (AMSC) and operational considerations for addressing voltage and power factor control in the context of a wind farm and its interconnection to the grid.

Historically, wind farm operators have employed mechanically-switched capacitor banks to regulate voltage at the point of utility interconnection. However, due to its highly and continuously variable nature, wind-dependent technology is poorly served by this traditional approach. There are two reasons for this. First, wind turbines, especially many of the induction type, can draw large amounts of reactive power (VARs) from the grid. This dependency triggers frequent remedial action to maintain voltage levels within the tolerances established by regulatory requirements. Although wind energy is variable, capacitors are able to switch only fixed amounts of VARs, and furthermore once they have been switched off they must wait five minutes until they can be re-energized in order to allow their trapped charge to dissipate. Accordingly, it is often difficult to maintain optimum amounts of reactive compensation for any length of time using switched capacitor banks alone. Second, in some instances, switching banks of capacitors to regulate voltage levels has been reported to cause excess stress on the wind turbine gearboxes.

Capacitor banks typically offer the lowest first-cost option for the control of voltage on a scheduled basis, and will undoubtedly remain a central element of almost every wind farm reactive compensation system. However, wind farm interconnection requirements often can not be satisfied with capacitor banks alone. Optimizing reactive compensation for wind farms merits a wider perspective that addresses the physical interconnection with utility grids, specific interconnection regulatory requirements, the business relationship with the utility itself, and the cost of operation and ownership of wind farm equipment. In extreme cases, especially in weaker areas of the grid, deficient interconnection schemes can even affect a wind farm's megawatt output and jeopardize revenues by forcing wind farms off-line. In this broader context, it is very important to design the reactive compensation system after careful analysis of the grid dynamics at the point of interconnection.



Wind farm generation costs have fallen by 50 percent over the last 15 years, moving closer to the cost of conventional energy sources, according to the Global Wind Energy Council.

Executive Overview of Voltage and Power Factor Control

This overview section discusses basic background information and issues, and is intended to provide the framework for understanding the problems that Dynamic VAR technology can resolve and the extended benefits that it provides.

What Are VARs?

Power consists of two components: real power and reactive power. Real power, which is the functional element that can do work (driving machines, lighting lights, etc.) exists when the voltage and the current are in phase with each other. Reactive power, on the other hand, exists when the voltage and the current are out of phase by 90 degrees. Although reactive power is unable to provide actual working benefit, it is often used to adjust voltage; so it's a useful tool for maintaining desired voltage levels. Every AC transmission system always has a reactive component, which can be expressed as "power factor." If the power factor is low and inductive (due to the wind turbine or other electrical equipment), then VARs are being drawn off of the grid, which reduces the system voltage. If the power factor is capacitive, then VARs are being added to the grid, which raises the system voltage. Some method is needed to manage power factor by injecting or absorbing VARs as necessary in order to maintain optimum voltage levels and optimize real power flow.

How is Voltage Commonly Controlled?

Traditionally, the easiest and least-cost way to manage VARs is to install shunt capacitor or reactor banks on the transmission system. Calculations determine how many VARs are needed at any given point, and appropriately sized banks of capacitors are strategically placed (usually rated in MegaVARs; 5 MegaVARs or 10 MegaVARs, for example). As voltage levels fluctuate, capacitor banks are switched on or off to either inject more VARs into the system or remove them, as required. The effect is that the system voltage is maintained within tolerances established by the transmission owner as well as regulatory requirements.

> *"Wind energy has now reached the milestone of 50GW of worldwide installed capacity and the industry is ready for a broader roll out. Wind energy has the maturity, clout and global muscle to deliver deep cuts in CO2, while providing a hedge against fluctuating fossil fuel prices and reducing energy import dependence."*
>
> Arthouros Zervos
> Chairman, Global Wind Energy Council
> September 2005

Capacitor Bank Switching Stresses Wind Farm Equipment

Although a cheap way of compensating for VAR losses, capacitor bank switching also results in an immediate, abrupt step-change in the voltage on the grid or the bus to which they are connected. The step-change instantaneously increases the torque, or twisting force, on a wind turbine gearbox. The variable nature of wind generation itself often triggers an extremely high number of the switching events that in some cases can begin to affect the reliability of the gearboxes. Like all induction motors, many induction-type wind turbines draw VARs off of the grid in amounts that fluctuate with changes in wind speed at the turbines. This, in turn, can cause an unacceptably large voltage drop at or near the wind farm interconnection point with the grid. So, given that these VARs need to be compensated in order to maintain voltage, it is not uncommon for a large site to experience fifty to a hundred switching events a day. In some cases the resulting gearbox stresses eventually take a toll, accelerating maintenance cycles of the gearbox.

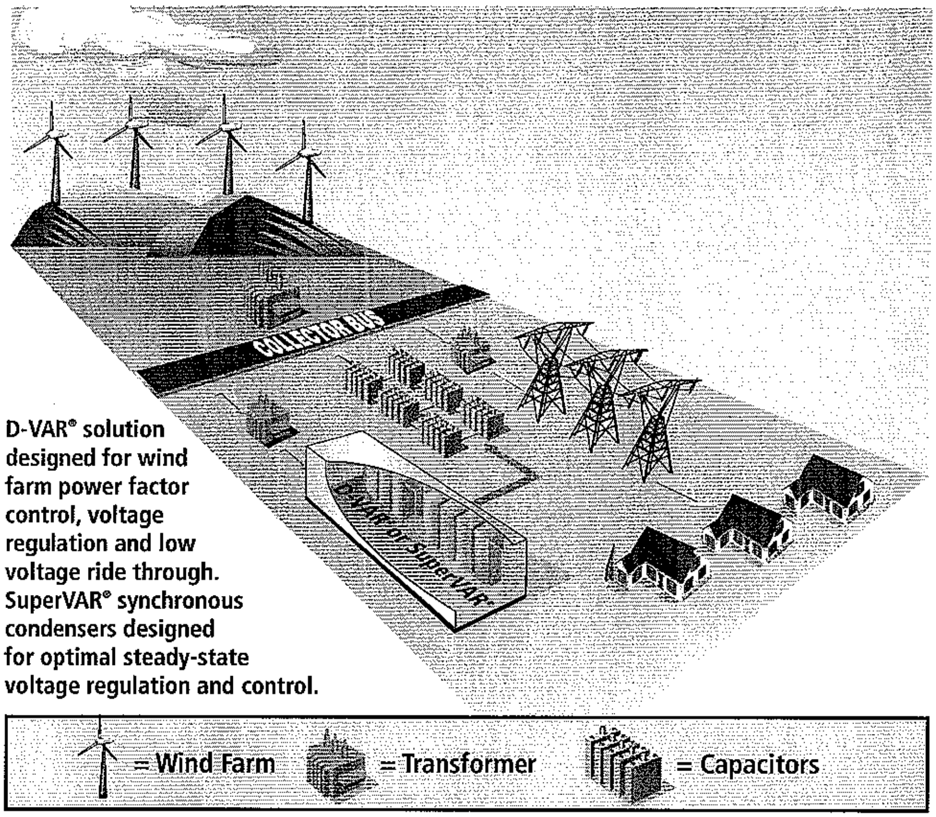
Remote Locations Complicate the Issue

The size of capacitor banks that can be used is governed by the strength of the grid or bus. Conventionally, the size of step-change in voltage from a switching event must be kept below a certain percentage of total voltage (typically two percent or below). A step change in voltage of any larger magnitude can potentially cause problems with other equipment in the substation at the wind farm. While first cost considerations may drive a preference for solutions employing fewer and larger capacitor banks, local conditions often require the use of a series of smaller banks relative to the strength of the grid at that location. Given that most wind farms are located in remote areas, the typical grid to which they connect is quite often relatively weak at that point because these grids are isolated from the generation sources.

The Business Side of Voltage and Power Factor Control

The party responsible for regulating the voltage at the wind farm is typically the wind farm owner. With the increasing prevalence of wind generation in recent years, the issue of grid connection requirements for wind farms has come under heightened scrutiny by regulators as well as regional transmission organizations and reliability councils. As a result of new rules such as those issued by the Federal Energy Regulatory Commission, wind farm owners in the United States are responsible for complying with more stringent and specific requirements related to voltage control and high or low voltage ride-through (the ability of the wind turbines to stay connected to the grid during voltage disturbances) for their wind farm than was the case in the early years of the emerging wind power industry. That responsibility is, in turn, driving wind farm owners and turbine manufacturers to incorporate dynamic VAR technology into their projects to enable compliance with these standards.

Regardless of who is responsible, all the parties have a vested interest in effectively and economically meeting the grid connection requirements. The ultimate objective, of course, is to ensure that wind farms provide a consistent, dependable source of real power generation while operating at peak efficiency and uptime with manageable cost of ownership. But also important to the utility is the power quality and reliability delivered to their other customers on the grid.



D-VAR® Systems: An Ideal Strategy for Wind Farm Applications

In recent years, AMSC's D-VAR technology has become a preferred and innovative solution to address grid interconnection requirements associated with wind farms. In addition to addressing grid connection requirements, the D-VAR system provides additional operational benefits such as mitigating step-voltage changes. It does this by using advanced power electronics, often in combination with traditional capacitor banks, to dynamically inject or absorb precise amounts of VARs into the system. Where capacitor bank switching alone is a binary on-off action, dynamic voltage control is more akin to a radio volume control with fluid, continuously adjustable levels.

D-VAR technology offers an economic strategy for complying with interconnection requirements that also can act as a two-way shock absorber, not only resolving VAR demand and/or voltage control issues created by the wind farm, but also enhancing the ability of sensitive wind turbine generators to avoid tripping off-line due to common voltage disturbances that occur on the transmission grid. Keeping wind turbine generators on-line has proven to be, in some locations, a significant problem with today's wind farms, and dynamic VAR technology is often worth the investment for this reason alone.

For wind farm owners, the D-VAR solution delivers several significant side benefits beyond ensuring compliance with standards. The elimination of switching-related stress on the gearboxes in some cases reduces maintenance requirements and extends the life of the equipment. Furthermore, because sudden voltage disturbances on the collector bus are mitigated, by using this solution, the wind farm has enhanced ability to ride through transient high or low voltage conditions. This maximizes the megawatt output and increases revenues.

For utilities, the D-VAR system eliminates large VAR demands and the resulting voltage swings caused by uncompensated wind farm operation. With this system in place, the wind farm looks to the utility much more like a conventional synchronous generator, in terms of the ability to dynamically control voltage. This mitigates or eliminates the need to install capacitor banks on the transmission system to control voltage. In cases where capacitor banks are called for, solutions may involve a smaller number of units with larger ratings — leading to lower costs for the utility with the added ability of the D-VAR system to offset these larger step voltage changes and smoothly switch capacitor banks.

With its integral control system, the patented D-VAR system can be custom-fitted to specific wind farm facilities. For example, a small (8 MVA) D-VAR device can be combined with a number of low-cost, medium-voltage capacitor banks to create an integrated, effective voltage and power factor control system for a wind farm.

AMSC has also developed DVC™ (Dynamic VAR Compensator) solutions and SuperVAR® machines that can address similar issues as the D-VAR system. DVC systems have been developed to address the need for large-scale solutions requiring hundreds of megaVARs (MVARs) of reactive compensation connected directly to the transmission grid. AMSC's DVC solutions are based on the widely successful D-VAR platform. They are a hybrid STATCOM/SVC solution that utilizes inverter-based FACTs (Flexible AC Transmission Systems) technology similar to D-VAR systems along with proprietary fast-switched capacitors and reactors.

SuperVAR machines use standard synchronous condenser frames and stator coils paired with advanced power-dense rotor coils made from AMSC's superconductor wire. The result is a synchronous condenser that is more efficient than conventional rotating machines — without the high rotor maintenance costs typical of older, conventional synchronous condensers.

SuperVAR machines are specifically designed for continuous, steady-state dynamic VAR support, with lower standby losses, higher output, and greater reliability than conventional synchronous condensers.

SuperVAR machines are cost-effective solutions that can provide tight voltage regulation and power factor correction to alleviate fluctuating voltage and VAR demands at wind farms.

How D-VAR Systems Work

D-VAR systems are dynamic reactive power sources of the flexible AC transmission system (FACTS) classification. As depicted in Figure 1, D-VAR devices are installed on the wind farm collector bus, continuously monitor the voltage at the point of grid interconnection, and take precise, instantaneous action as necessary. The variable output of the D-VAR device is typically the first source used to regulate voltage. As additional compensation is required, the patented control system of the D-VAR system will switch a capacitor bank (or reactor) in or out. At the exact moment of switching, the DVAR device instantaneously injects (or absorbs) the same amount of VARs as the capacitor bank, thereby eliminating the step voltage change that would otherwise occur. The D-VAR system then resumes its normal voltage regulation mode, dynamically injecting or absorbing VARs as required. Notably, because of the capacitive and inductive capabilities of the D-VAR system it can handle a significant percentage of the events that would otherwise traditionally trigger a capacitor-bank switch; the annual number of capacitor switching events can be reduced. This results in less maintenance time and lower cost of ownership of the capacitor bank switches or breakers.

In addition to the operation inside the wind farm that Figure 2 shows, the D-VAR system can also help protect the wind farm from voltage disturbances that normally occur on the transmission grid (such as voltage sags or swells). The sensing and control scheme of the D-VAR system continuously monitors the voltage at the wind farm collector bus or point of connection to the transmission grid. When the voltage rises or

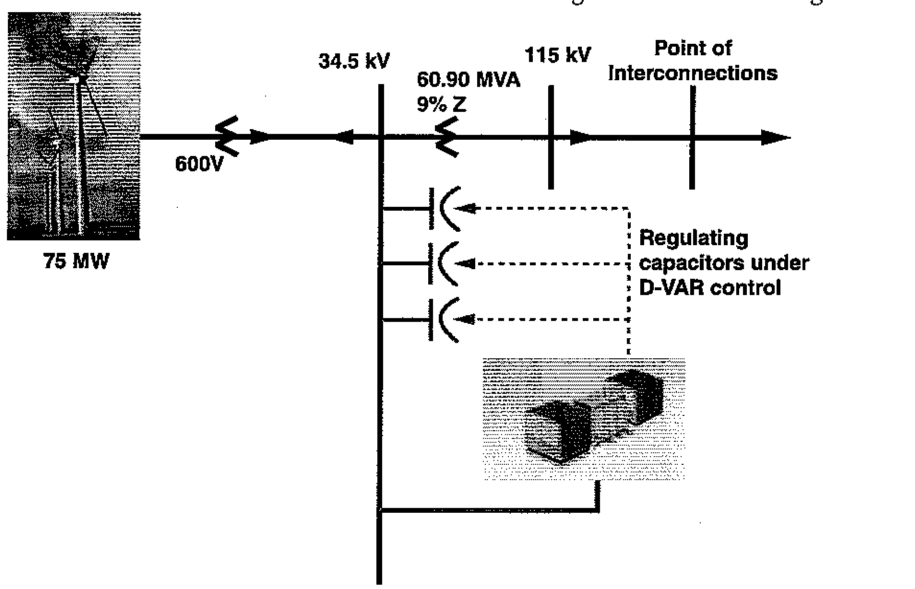


Figure 1: Typical Dynamic VAR System and Capacitors Connected to a Wind Farm. The dynamic VAR system shown in the figure continuously monitors the collector bus and/or transmission grid voltage of a typical wind farm to ensure that the voltage remains within the utility specified range. Continuous voltage regulation is accomplished by a combination of VAR injection or absorption from the dynamic VAR system, and by controlled, seamless switching of capacitor banks. In addition, the system mitigates voltage transients that typically originate on the transmission grid and can cause the wind turbine generators to trip off-line.

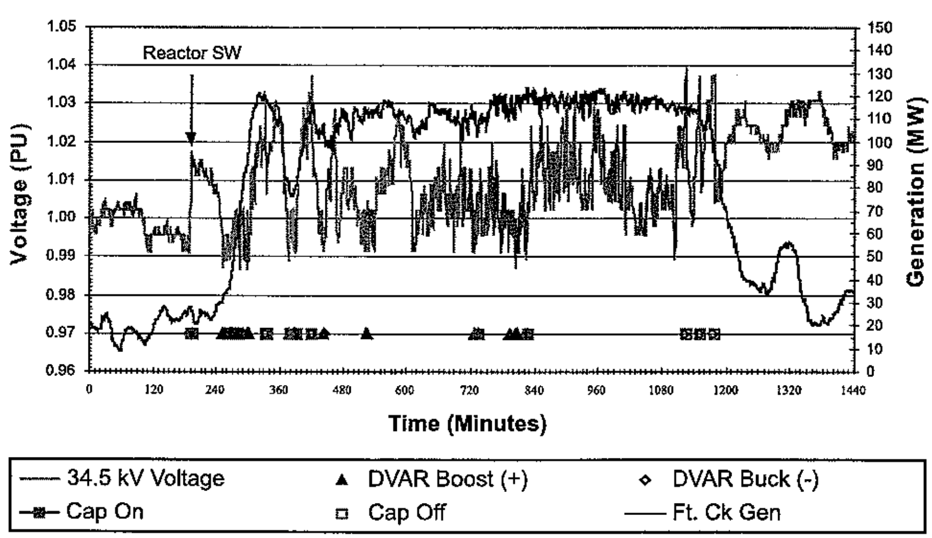


Figure 2: Example of a tight voltage profile maintained through varying wind conditions at an existing 130MW wind farm using a D-VAR system solution.

falls to a level outside a preset target or bandwidth, the D-VAR system responds instantaneously. It injects or absorbs sufficient reactive power to fully offset the event, maintaining the voltage inside the desired bandwidth levels.

Considerations in Developing a Site-Specific D-VAR Solution

Although there are some factors that are common to all wind farm sites, each has unique aspects that must be considered when specifying the voltage and power factor control solution. Some wind farms will be fortunate enough to interconnect with a very strong grid that can tolerate the VAR demand of the wind farm without the assistance of anything more than simple capacitor banks. Other wind farms may be small enough that their operation does not negatively affect the transmission grid or they fall below the minimum MW size to which less stringent standards apply.

> *"Wind power's rapid growth provides what is potentially the quickest and best supply-side option to ease the natural gas shortage."*
>
> Arthouros Zervos
> Chairman, Global Wind Energy Council
> September 2005

These situations are somewhat unusual, however, due to two aspects of the basic economics of wind energy. First, scale economies are driving the construction of larger wind farms that have higher output relative to the local capacity of the grid. Second, wind farms by their nature tend to be located in remote areas where power delivery grids are not as strong. As a result of these factors, many wind farms require a voltage control strategy both to ensure compliance with regulatory interconnection standards as well as to ensure optimal operation. Factors to consider include the strength of the local grid connection, the size of the wind farm, the type of wind turbine generator and the interconnection specification of the grid owner. The best way to develop a strategy for voltage control is to do a site-specific analysis. This includes a detailed technical analysis of the grid strength and requirements, and results in an in-depth report with recommendations.

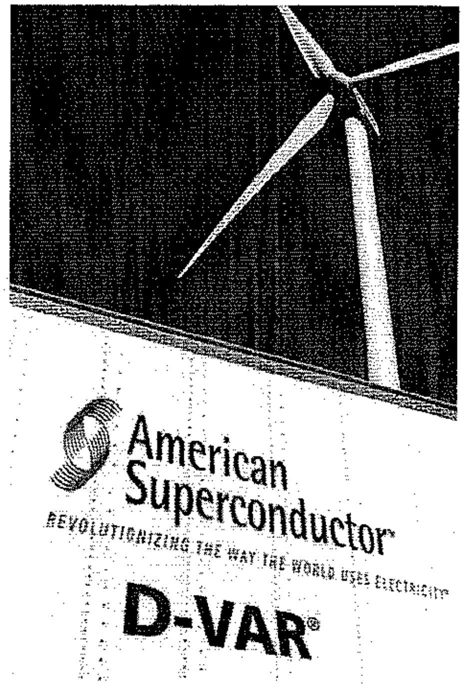
American Superconductor's staff of very experienced utility transmission planners will provide these studies free of charge or obligation. The company makes these services available to its customers because it believes it is the first step in understanding system requirements that will lead to recommendations for the best and most economic solution to meet these needs.

Some Cost of Ownership Factors

Wind generation facilities are long-term investments, so in order to accurately evaluate the reactive compensation options, ongoing and cumulative cost of ownership must be factored in with the initial cost of infrastructure elements. Most often this includes a calculation of the cost of running a system over time, taking into account losses and efficiencies. These losses include the amount of power necessary to operate the balance of plant equipment, including reactive compensation solutions — power that must be paid for.

For example, as with almost all power equipment, cooling is a consideration. With power electronic devices, the two basic choices are liquid cooling and air cooling. Air cooling, of course, is much less complicated because it does not require plumbing, pumps, etc., and the ongoing operational and maintenance costs are also substantially lower because the more simple air-cooled system draws significantly less auxiliary power than a conventional liquid cooled system.

Another factor to consider is the flexibility of the control system. This is not only important in the initial phases



of the installation but also after the wind farm is up and running because it governs how closely the equipment can be further tuned to the specific wind farm conditions and requirements. One important item to consider in designing a wind farm is the willingness of the supplier to customize their product. Conditions are also likely to change over time, and the inherent capability of the control system to be adapted as the wind farm changes or expands is also critical. In addition, like all similar equipment, dynamic VAR devices have maintenance requirements. Is the manufacturer able to offer sufficient levels of support? For example, some systems such as the D-VAR system or DVC devices from AMSC can be monitored 24/7/365 by the manufacturer, either at very modest cost or as part of an annual maintenance package. This kind of service reassures wind farm owners that the devices are working properly and providing the protection and reliability they expect. Other services should include full hardware and software support specific to the installation. The maintenance factor is part of the ongoing and lifetime cost of ownership.

Summary

It is very commonplace for today's generation of wind farms – larger-scale operations located in remote areas of the grid – to require more sophisticated voltage control strategies than their early predecessors. Wind farms also can have unique circumstances and operational considerations that warrant evaluation of the merits of traditional "voltage control by capacitor banks" approach. Employing dynamic VAR devices, sometimes in combination with control of capacitor banks, eliminates many of the negative consequences of traditional solutions. Both the wind farm developer/owner and ultimately the utility benefit from this approach.

The D-VAR system advantages for the wind farm include:

- Grid interconnection standards are met.
- Voltage sags or swells originating from the transmission grid are mitigated. This enhances the ability of the wind farm to stay online and helps to prevent nuisance tripping of the wind turbine generators. This also helps maximize the power output of the wind farm which leads to increased revenues.
- Step-voltage changes due to local or remote capacitor-bank switching are mitigated, or eliminated, thus preventing excess gearbox stress or failure.
- Capacitor-bank switching events are minimized, which reduces switch maintenance costs.
- Overall grid interconnection costs are minimized.

The D-VAR system advantages for the utility:

- Large VAR demands are eliminated, as are the resulting voltage swings caused by uncompensated wind farm operation. The wind farm maintains a consistent, smooth voltage profile.
- In some cases, the need to install additional capacitor banks on the transmission system is eliminated.
- If transmission capacitor banks are installed for any reason, their impact to the local wind farm is minimized.

About American Superconductor Corporation

American Superconductor (AMSC) is the manufacturer of the D-VAR and DVC dynamic reactive compensation systems which provide voltage support to utility transmission and distribution systems. In addition to wind farms, AMSC D-VAR systems are also being used worldwide to address a variety of grid-related problems such as voltage instability, power transfer constraints and steady-state voltage regulation.

AMSC is the world's principal vendor of high temperature superconductor (HTS) wire and large rotating superconductor machinery, and it is a world leading supplier of dynamic reactive power grid stabilization products. AMSC's HTS wire and power electronic converters are at the core of a broad range of new electricity transmission and distribution, transportation, medical and industrial processing applications, including dynamic reactive power grid stabilization solutions, large ship propulsion motors and generators, smart, controllable, superconductor power cables and advanced defense systems. The company's products are supported by hundreds of patents and licenses covering technologies fundamental to Revolutionizing the Way the World Uses Electricity™. More information is available at http://www.amsuper.com.

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www.amsuper.com

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Transmission Grid Solutions

DVC™ - Dynamic VAR Compensator Solutions

American Superconductor's (AMSC™) DVC (Dynamic VAR Compensators) solutions are based on the widely successful D-VAR® system. They are a hybrid STATCOM/SVC solution that utilizes inverter-based FACTs (Flexible AC Transmission systems) technology similar to D-VAR systems along with proprietary fast-switched capacitors and reactors. AMSC has developed DVC solutions to address the need for large-scale solutions requiring hundreds of megaVARs (MVARs) of reactive compensation.

The DVC systems are modular and scalable. They can be customized to meet any dynamic reactive compensation need and are built in sizes ranging up to several hundred MVAR connected to a single point on the transmission grid.

The illustration below shows the basic configuration of a typical DVC solution. The combination of proven inverter-based dynamic VARs and fast-switched shunt elements provides large-scale DVC solutions that have high availability and performance and are more cost effective than STATCOM and SVC solutions. The AMSC D-VAR® modules at the heart of the DVC solution have a proven track record in the field and have performed with the highest of reliability.

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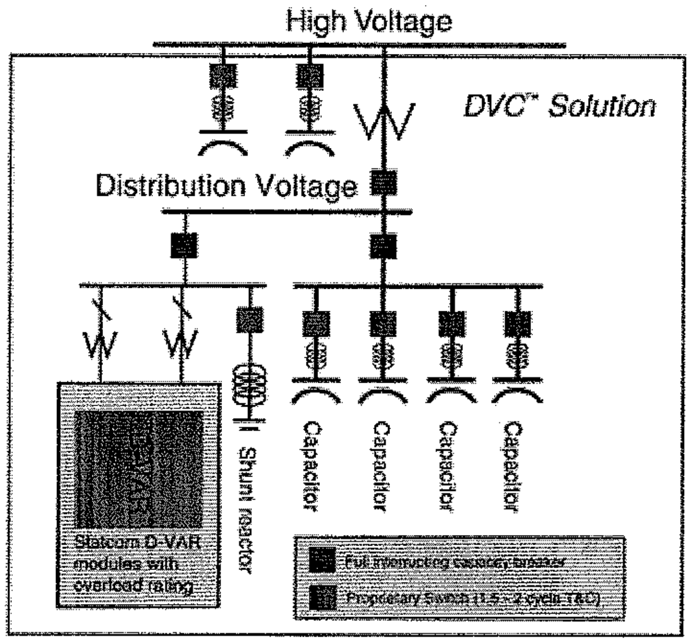

AMSC's PowerModule™ power converters are the building blocks that make up the D-VAR systems that are integrated into the DVC system. These inverters are highly power dense and have transient overload capability which allows the DVC solution to be even more cost effective.

DVC systems are modular and easily expandable to meet ever-changing grid conditions and customer needs. DVC solutions can help address reactive compensation problems for various applications. Some of the applications include:

- Voltage Stability / Voltage Collapse - uncontrolled rapid decline in system voltage
- Steady-state Voltage Regulation - radial line, wind farms
- Import / Transfer Capability Restrictions - limited ability to reliably import, export or transfer power

Where Can I Get More Information About DVC Solutions?

AMSC's grid solutions team has decades of experience in utility transmission and distribution planning and will work with you to identify a highly effective, low cost solution that will meet your specific needs and requirements. For more information about DVC systems for a more reliable grid, contact:

American Superconductor
Tim Poor, Director of Sales
8401 Murphy Drive
Middleton, WI 53562
Ph: 608-831-5773
tpoor@amsuper.com

American Superconductor™

REVOLUTIONIZING THE WAY THE WORLD USES ELECTRICITY™

Dynamic Reactive Power Compensation

Utilizing State of the Art Power Electronics Technology

Benefits

- Hybrid Statcom/SVC technology — Builds off of widely successful D-VAR STATCOM platform
- Modular components — easily expandable
- Less cost than conventional SVC solution

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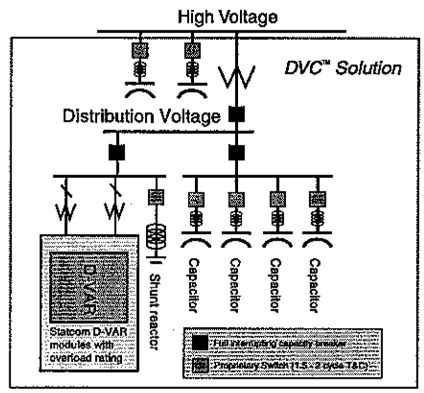

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Applications
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- INDUSTRIAL
- WIND ENERGY
- ▸ UTILITY
- SHIP PROPULSION

Utility

Flexible AC Transmission Systems (FACTS) for Utility Applications

As electricity demand continues to rise rapidly, there is an immediate need to increase the quality and reliability of power supplying today's highly complex and digital economy. Environmental concerns, permitting issues and high costs have slowed the expansion and rebuilding of the current power network. Solution options such as FACTS (Flexible AC Transmission Systems) devices can optimize new and existing transmission and distribution lines, making them highly efficient and capable of reliably delivering better quality power to satisfy rapidly growing energy demands.

Some of the benefits of installing a FACTS device include:

- Dynamic reactive power compensation
- Steady-state and transient stability enhancement
- Voltage regulation
- Power transfer capacity increase
- Three-phase voltage balancing
- Reduced transmission losses
- Flicker mitigation
- Oscillation damping

Static VAR Compensators (SVC)

American Superconductor (AMSC) is North America's only static var compensator (SVC) manufacturer. AMSC's SVC is a solid-state FACTS device that provides dynamic reactive power compensation based on proven thyristor technology. SVC's can respond to the fastest of voltage transients that appear on power systems and can reduce the risk of detrimental voltage collapse. The vernier control provided by the SVC also allows for steady state voltage regulation, maintaining a smooth voltage profile. AMSC's SVC solutions can be configured to meet specific customer requirements. Our highly experienced power systems engineering team can optimize the SVC configuration to best fit your needs. AMSC provides full turnkey services and offers extensive maintenance and monitoring capabilities. >>More information on AMSC SVC

D-VAR STATCOMS

D-VAR® (Dynamic VAR) STATCOMS provide a powerful and

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cost-effective source of dynamic VARs for a wide range of operational needs. D-VAR systems utilize a proprietary and advanced control and monitoring system that detects and instantaneously compensates for voltage disturbances by injecting leading or lagging reactive power. At the heart of each D-VAR system are American Superconductor's (AMSC) PowerModule™ advanced power electronic converters. PowerModule inverters are an intelligent, fully integrated four-quadrant power converter with high power density. D-VAR STATCOMS can respond to voltage events that are both rapid and slow, providing the same level of security, reliability, and enhancement to the grid as an SVC. >>More information on AMSC D-VAR systems

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- MOTORS, GENERATORS & SYNCHRONOUS CONDENSERS
- INDUSTRIAL POWER QUALITY SOLUTIONS
- POWER CONVERTERS
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Applications

- SEMICONDUCTOR
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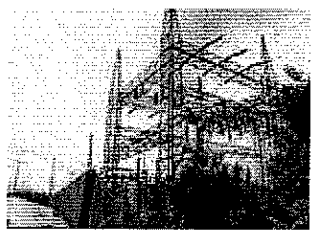
Transmission Grid Solutions

Solutions for Improving Reliability and Security of Transmission Grids



American Superconductor offers a range of products and services to address the need to make transmission grids more reliable and secure. Our dynamic reactive power grid stabilization products are powerful and economical solutions for addressing grid reliability problems. There are a number of configurations to optimize a transmission reliability system that is best suited to their exact requirements.

At the heart of AMSC's reactive power grid stabilization solutions are AMSC's state-of-the-art PowerModule™ PM1000 advanced power electronic converters for D-VARÂ® systems or AMSC's high temperature superconductor (HTS) rotating machines. Each of these dynamic reactive compensation devices is capable of injecting large amounts of real and/or reactive power to boost voltage on the transmission network within milliseconds.

AMSC works with cable manufacturers to design HTS cable systems to increase power system capcity and expand the "solution space" for grid planners and operators.

Transmission Planning Expertise

American Superconductor is a world leader in developing HTS cable projects. AMSC combines knowledge of transmission planning, refrigeration system integration and project execution to provide a seamless transmission solution. AMSC starts with a customer's transmission planning team to determine the best solution for their network. Should an HTS cable be the correct solution, AMSC develops a project specification and works with the cable system and refrigeration system manufacturers to provide solutions on time and within budget.

Comprehensive Transmission Solution Planning:

- Load flow studies

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- Fault Curren
- D-VAR® sys
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- Secure Supe System
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- Dynamic and stability analysis
- Transfer capability studies
- Power quality and reliability studies

For more information or to request a transmission planning study now, please click here.

Dynamic Reactive Power Products

Dynamic reactive compensation devices can be configured to meet a wide range of customer requirements.

D-VAR®

AMSC's Dynamic-VAR, or D-VAR®, systems provide dynamic reactive compensation to mitigate low voltage or voltage instability on transmission networks. D-VARÂ units are modular in size, ranging from +/- 1.0 to 8.0 continuous and +/- 3.0 to 24.0 instantaneous MVAR output.AMSC's dynamic reactive compensation devices can:

Eliminate low system voltage / voltage collapse as obstacles to increased load serving capacity (10-50% increase)

Provide both real and reactive power to mitigate voltage stability problems within milliseconds

Defer new transmission line construction until thermal line limits are reached

Because D-VAR systems are mobile assets they can be located exactly where voltage mitigation is needed most in the network.

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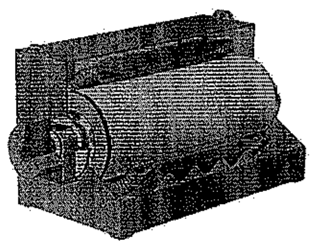
Motors, Generators & Synchronous Condensers

10 MVAR SuperVAR® Dynamic Synchronous Condenser



The primary function of the 10 MVAR SuperVAR Dynamic Synchronous Condenser (DSC) is to compensate the reactive power on the utility grid. Reactive power, the out-of-phase component of AC power, can be either inductive (voltage leading current, corresponding to inductive reactance) or capacitive (voltage lagging current, corresponding to capacitive reactance). Reactive power does not provide useful energy at the load; however it is a common component of AC power grids and their loads, which are usually inductive but at times can also be capacitive.

Reactive power limits the amount of real power that can be handled on a transmission or distribution grid. A synchronous condenser compensates either an inductive or a capacitive reactance by introducing the opposite type of reactance thus optimizing the useful in-phase power throughput of the grid. The SuperVAR™ condenser design is based on AMSC's proprietary rotating machine design and hardware expertise developed during the last decade.

The SuperVAR design offers a cost-effective alternative to reactive power compensation compared to synchronous generators (the traditional method for compensating reactive power). The DSC allows the generators to operate optimally in producing real power for which a power company is ultimately paid. It is also cost-effective compared to alternatives which use capacitor banks or power electronic systems.

Specifications

- 10 MVAR, 13.8 kV at 60 Hertz
- Steady state continuous duty
- Economic source for dynamic VAR support
- Supports transient loads at multiples of machine rating

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- 10 MVAR

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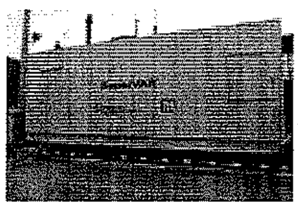
- High machine operating efficiency
- Long winding life

Motors, Generators & Synchronous Condensers

SuperVAR® Dynamic Synchronous Condensers



American Superconductor's SuperVAR dynamic synchronous condenser is a new, breakthrough product that stabilizes grid voltages, increases service reliability and can help maximize transmission capacity.

Utilities today face an ever-growing demand for higher quality, reliable power and increased transmission capacity. The key to increasing reliability and capacity is ensuring that grid voltage is properly regulated. This helps prevent service disruptions, damage to electrical service equipment, generating plants and other components of the AC power grid and can help maximize transmission capacity. Utilities keep voltage levels stable by maintaining a balance of real power (watts) and reactive power (VARs) on their transmission grids.

American Superconductor's SuperVAR machines are rotating machines, much like motors and generators, and utilize high temperature superconductor technology and serve as reactive power "shock absorbers" for the grid, dynamically generating or absorbing reactive power (VARs), depending on the voltage level of the transmission system.

AMSC's SuperVAR machines use standard synchronous condenser frames and stator coils mated with new, power-dense rotor coils made from AMSC's HTS wire. The result is a synchronous condenser that is more efficient than conventional machines - without the typically high rotor maintenance costs. SuperVAR machines are specifically designed for continuous, steady-state dynamic VAR support while having multiples of their rated output in reserve for transient problems. The HTS rotor enables these machines to provide up to eight times their rated capacity for short periods. AMSC expects to also extend the product line to include units of substantially larger ratings.

Benefits

- Transient dynamic voltage support and stability

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(leading and lagging VARs) at a multiple of the machines rating

- Economic transmission voltage support and stability improvement
- Increased transmission capacity by reducing transmission losses
- Power factor correction during steady state operation
- Stable operation up to its rated load in either leading or lagging mode
- Minimizes operating power consumption
- Minimizes harmonic content
- Requires less maintenance on machine rotor windings
- Modular transportable design
- Easy installation

VARs and Reactive Power

Voltage is the "pressure" that drives electrical current through power lines. Reactive power, which is measured in VARs (volt-ampere-reactive), is the component of electricity that maintains the proper level of voltage in transmission lines to drive "real power," which is measured in Watts, through the power lines to customers.

Reactive power cannot be stored and must be externally supplied to the power grid.

Synchronous condensers share much of their architecture with electric synchronous motors and generators. Their primary function is to stabilize grid voltage by injecting or absorbing reactive power. Reactive power, which can also be understood as the "out-of-phase" component of AC power, can be either lagging (current lagging voltage, corresponding to inductive reactance) or leading (current leading voltage, corresponding to capacitive reactance).

As power demands increase in any AC system, the need for reactive power generally increases. When the transmission grid is forced to deliver large amounts of reactive power over long distances, it can limit the amount of real power that can be generated and delivered across a transmission grid. Therefore, it is advantageous to produce the necessary reactive power close to the loads.

The HTS Advantage

By utilizing AMSC's HTS wire, SuperVAR machines provide a more efficient system with significant advantages over conventional synchronous condensers such as lower standby losses, higher output, lower cost and higher reliability. In addition, the HTS rotor design increases the device's over-excitation and under-excitation output limits to its full-rating without loss of critical clearing time following a transient fault. SuperVAR machines do not experience thermal fatigue of the field coils as the VAR output is varied from no-load to full-load allowing SuperVAR synchronous condensers to be used for peaking as well as base load applications without worries of loss of life due to frequent load changes. These machines do not introduce harmonics into the grid, but do retain high operating efficiency (losses versus VARs) down to 20% of its rated output.

Demand for electric power continues to grow and utilities are looking for ways to leverage their existing grid assets to meet rising customer demand for more reliable power. SuperVAR machines enable existing transmission assets to be operated at higher capacities thereby minimizing the need to construct new power generating facilities or install additional transmission lines in areas of increasing demand. SuperVAR machines can also serve as lower cost replacements for old, polluting inner city Reliability-Must-Run (RMR) generating facilities which are required to operate in order to maintain system reliability and voltage support. The innovative design of SuperVAR synchronous condensers provides a highly efficient alternative to dynamic voltage grid support available from other devices.

Is SuperVAR® or D-VAR® the Right Solution for my Grid?

The SuperVAR machine is a new product that complements AMSC's family of reactive power grid stabilization solutions which includes AMSC's D-VAR (dynamic VAR) systems.

- SuperVAR synchronous condensers are specifically designed for continuous, steady-state dynamic VAR support and they maintain a reserve for transient problems.

- D-VAR systems - which are based on AMSC's PowerModule™ power electronic converters - are designed to solve local voltage issues through a controlled, directed output thus addressing more specific existing or known transient problems.

Transmission and distribution grids are complex systems that can require a combination of steady-state dynamic and transient VAR support to ensure reliable power delivery. AMSC's transmission planning and sales teams have decades of experience in the power industry. AMSC works together with utilities and power system operators and conducts extensive studies in order to deliver optimized transmission grid solutions.

Sheet

American Superconductor™

REVOLUTIONIZING THE WAY THE WORLD USES ELECTRICITY™

Dynamic Reactive Power Compensation

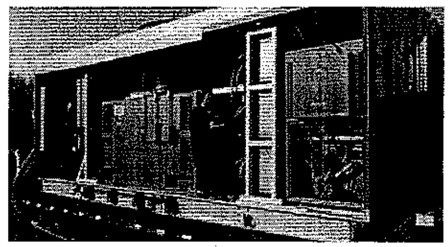
High Temperature Superconductor Technology

Benefits

- Provides cost effective, steady state voltage regulation
- Delivers superior transient response
- Improves grid reliability by stabilizing voltage
- Generates/absorbs VARs dynamically
- Mobile version enables quick deployment
- Adds beneficial inertia to system for greater stability
- More compact, lighter and less costly to operate than conventional synchronous condensers
- High efficiency, even under partial loads (down to 0.3 pu)
- Field windings not affected by thermal cycling

What are SuperVAR Synchronous Condensers?

SuperVAR™ synchronous condensers use High Temperature Superconductor (HTS) technology and can dynamically inject or absorb reactive power (VARs), depending on transmission or distribution system needs.



SuperVAR synchronous condensers serve as reactive power "shock absorbers" for the grid.

SuperVAR systems continuously regulate grid voltages to preserve the desired steady state voltage profile and avoid high or low transient voltages, helping to prevent service disruption and damage to electrical service equipment, generating plants and other components of the AC power grid.

Operational Description

SuperVAR systems feature a low cost, efficient synchronous HTS rotating machine that helps solve the imbalance between supply and consumption of VARs in order to keep the power system working in an optimum state. SuperVAR systems also add inertia to transmission systems and contribute to overall system stability by acting as a shock absorber for system transients.

SuperVAR systems monitor voltage at the transmission and/or distribution level and depending on the system's need, can dynamically inject or absorb VARs to keep grid voltages within the desired range. SuperVAR systems offer fast-reacting transient dynamic voltage support and can be overloaded at multiples of their ratings for up to 2 minutes.

SuperVAR systems are shunt-connected and have an output of 13.8 kilovolts (kV). SuperVAR systems produce minimal harmonic content and, therefore, require no special filtering.

SuperVAR communication and control systems allow for remote adjustment of voltage set points and can also control multiple shunt capacitors or reactors to expand total dynamic VAR range.

Specifications

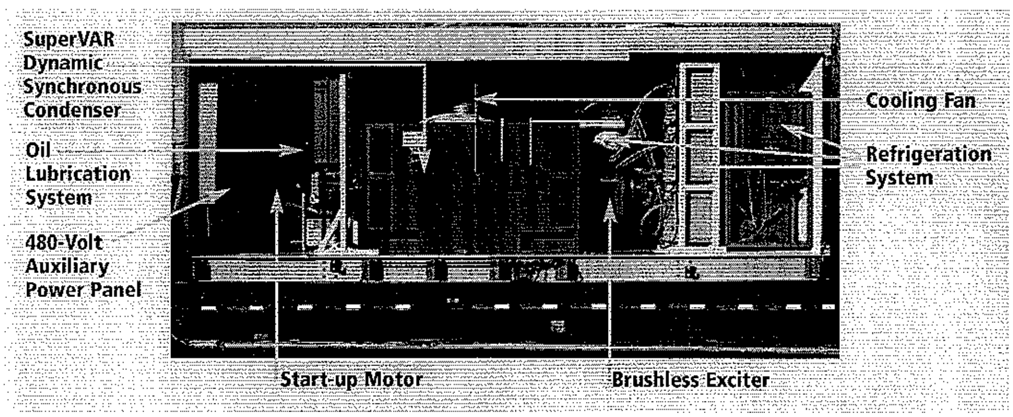
Continuous Rating:	±10 MVAR
Transient Overload Rating:	2 - 8 pu
Voltage Rating:	13.8 kV line to line
Losses:	Less than 1.7% of rating
Communication:	Remote adjustment of VARs
Connections:	NEMA enclosures
Auxiliary Power:	480V, 3-phase, 75 kW
Design Standards:	IEE/ANSI C50.13-2002
Dimensions:	Typically 8' x 10' x 24'
Other:	System packaged in enclosure Minimal on-site installation Contains all auxiliary systems Remote monitoring Self-protecting

Product Applications

SuperVAR Dynamic Synchronous Condensers help alleviate voltage problems in many applications including:

- Reactive Compensation - Transmission and Distribution Systems
- Steady State Voltage Regulation - Long Radial Delivery Systems
- Dynamic Power Factor Correction - Large Industrial Sites
- Flicker Mitigation for Sensitive Power Quality - Steel Mills, Mines, Arc Furnaces

The first SuperVAR synchronous condenser (rated at ±8 MVAR) is being used by the Tennessee Valley Authority to mitigate voltage flicker at a steel mill in Gallatin, Tennessee



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10 September 2003

Superconducting Dynamic Synchronous Condenser For Improved Grid Voltage Support

Swarn Kalsi, David Madura, Ray Howard, Greg Snitchler and Tim MacDonald
and
Dale Bradshaw, Ian Grant and Mike Ingram

Abstract-- **Synchronous condensers are an attractive source of dynamic VARs (both inductive and capacitive) to improve system stability and maintain voltages under varying load conditions and contingencies. A synchronous condenser is a rotating machine that runs synchronized with the grid. Its field is controlled with a voltage regulator to either generate or absorb reactive power as needed by the power system. American Superconductor Corporation's (AMSC) proprietary SuperVAR™ Dynamic Superconducting Condenser (DSC) machines upgrade existing technology by using a conventional armature mated with a field winding made from High Temperature Superconducting (HTS) wires. The result is a DSC that is both more efficient and has lower maintenance than conventional machines. It can provide up to 8 pu current for short periods to support transient VAR requirements. The Tennessee Valley Authority (TVA) is sponsoring the development and field testing of an 8 MVAR prototype unit to be followed by five 10 MVAR production units. Larger units are planned for the future. This paper describes features of the DSC and its performance in grid applications.**

Index Terms—**Superconducting motors and generators, High temperature superconductors, Superconducting rotating machines, Synchronous condensers, Superconducting condensers**

I. NOMENCLATURE

HTS – High Temperature Superconductors
LTS – Low Temperature Superconductors
DSC - Dynamic Superconducting Condenser
BSCCO – First-generation HTS superconductors
DVAR - A statcom applied at distribution voltage, may include energy storage
FACTS - Flexible AC transmission systems

II. INTRODUCTION

Dynamic VARs are an important requirement for increasing the electric loading of transmission lines. While static capacitors are widely used, a dynamic response is often essential to maintain dynamic and voltage stability and prevent voltage collapse. Superconducting synchronous condensers are expected to be a lower cost and more reliable device and thus superior to FACTS devices in this application.

The following quote from a paper by Prof. Wollenberg[i] summarizes the importance of VARs in a grid - *"...But why should we want to transmit reactive power anyway? Is it not just a troublesome concept, invented by the theoreticians, that is best disregarded? The answer is that reactive power is consumed not only by most of the network elements, but also by most of the consumer loads, so it must be supplied somewhere. If we can't transmit it very easily, then it ought to be generated where is needed."*

Reactive power does not provide useful energy at the load (useful energy is supplied by the in-phase component); however it is a common component of AC power grids and their loads which are usually inductive but at times can be capacitive too. Over a given AC line, as power demand increases the need for reactive power increases more rapidly as shown in Figure 1 for a 200 km long 500 kV transmission line with 1000 MW Surge Impedance Loading (SIL) . Lack of reactive support can limit the amount of real power that can be delivered across a transmission grid and cause congestion, resulting in Transmission line Loading Relief calls (TLRs). It is advantageous to produce the necessary reactive power close to the loads. This applies equally for both static and dynamic VARs.

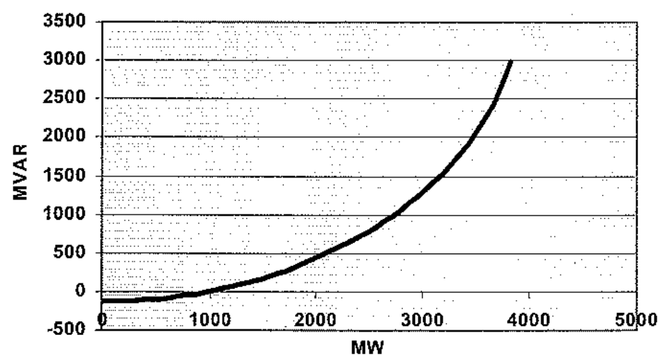

Figure 1: MVARs requirement increases rapidly as real power on the sending end increases

III. PERFORMANCE FEATURES

A synchronous condenser shares much of its architecture with electric synchronous motors and generators. Its primary function is to compensate the reactive power on the grid.

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10 September 2003

Reactive power, the out-of-phase component of AC power, can be either lagging (current lagging voltage, corresponding to inductive reactance) or leading (current leading voltage, corresponding to capacitive reactance).

A DSC is capable of generating or absorbing reactive power (MVARs) at needed locations on a power grid. DSC machines are inherently capable of continuous steady-state as well as dynamic reactive compensation while having multiples of their rated output in reserve for transient events. DSC units with superior dynamic capabilities can be applied throughout the grid to supply or absorb VARs as needed.

Table 1 compares DSC with other competing products. Key benefits of a DSC are summarized as follows[ii]:

- Fast reacting transient dynamic voltage support and stability (leading and lagging VARs) at a multiple of the machines rating
- Fully capable of either leading or lagging VARs mode
- Low losses
- Low maintenance and high reliability
- Does not generate harmonics
- Simple installation
- Can be manufactured for 13.8 kV and higher voltage ratings
- Easily made resistant to poor quality or lost auxiliary power including severe voltage sags
- Contains virtually no environmentally sensitive materials (small quantities of lubricating oil)

By utilizing the current-generation HTS wire (BSCCO-2223), DSC machines provide[iii] a more efficient system with significant advantages over conventional synchronous condensers such as lower standby losses, higher output, lower cost and higher reliability. In addition the HTS rotor design increases the device's over-excitation and under-excitation output limits to full-rating without loss of critical clearing time following a transient fault. DSC machines do not experience thermal fatigue of the field coils as the VAR output is varied from no-load to full-load. Thus DSC synchronous condensers can be used for peaking as well as base load applications without loss of life due to frequent load changes. These machines do not introduce harmonics into the grid, and do retain high operating efficiency (losses versus VARS) down to 20% of their rated output.

TABLE 1: COMPARISON OF SUPERVAR™ DSC WITH OTHER COMPETING TECHNOLOGIES

Functional Characteristics	Capacitors	STATCOM	SVC	D-VAR	SuperVAR DSC
Solution type	Steady-state	Steady-state and Dynamic	Steady-state and Dynamic	Steady-state and Dynamic	Steady-state and Dynamic
Continuous VARS output	Leading	Leading / Lagging	Leading / Lagging	Leading / Lagging	Leading / Lagging
Inherent transient overload rating	No	No	No	3x	up to 8x nominal
Real power output	None	None	None	Optional	None
Response to transient events	Slow	Sub-cycle	Sub-cycle	Sub-cycle	Sub-cycle
Response to severe (deep) voltage dips	No	Sub-cycle	No	Sub-cycle	Sub-cycle
Ability to control other devices	None	Yes	Yes	Yes	Yes
Independent phase control	None	Yes	None	Yes	None
Discretely controlled output	No	Fast	Fast	Fast	Slow
Harmonic compensation required	Application dependent	Yes	Yes	Application dependent	No
Creation of over voltage spikes	Yes	No	No	No	No
Output dependent on bus voltage	Decreases with square of voltage	Decreases linear with voltage	Decreases with square of voltage	Decreases linear with voltage	Independent of bus voltage
Efficiency	99%	98-99%	98-99%	98-99%	98-99%
Foot print	Small	Medium	Large	Small	Small
Ease of installation	Simple	Complex	Complex	Simple	Simple
Cooling	Ambient air	Liquid	Liquid	Ambient air	Air/Liquid
Availability and delivery time	6 months	12 months	12 months	6 months	6 months
Losses	Low	High	Medium	Low	Low
Inertia adds to system stability	No	No	No	No	Yes

The HTS field winding is maintained at essentially constant temperature for all levels of field current. The stationary reference frame employs refrigeration elements which are high-reliability devices available from other applications. On the other hand in a conventional machine, the field winding current typically varies from 1 to 3 pu which changes conductor temperature. As a result of this conductors experience significant thermal expansion which causes mechanical fatigue of the insulation leading to eventual failure.

Sensitivity to Auxiliary Voltage

An important issue that is often overlooked and which directly affects reliability is the auxiliary supply to FACTs devices. Supply for control equipment, electronics devices, and cooling is often obtained directly from the same voltage source that the FACTs device is supporting. When a fault occurs, poor quality of the auxiliary supply to the FACTs equipment may trip the device at exactly the moment that it is needed. A DSC is largely immune to this concern, since its refrigeration equipment has significant thermal inertia and its control equipment has a low load and can easily be supported on a small UPS.

IV. Design Configuration

The major components of a DSC are shown in Figure 2. Only the field winding employs HTS windings cooled with a cryocooler subsystem to about 35-40K. The cryocooler modules are located in a stationary frame and a fluid such as gaseous helium or liquid neon is employed to cool components on the rotor. The stator winding employs conventional copper windings.

Cooling systems have been developed for cooling HTS field windings to 30 K. These systems employ Gifford-McMahon (GM) cryocoolers, which are the same components widely used by MRI and vacuum system industries and are available as catalog items with a high implicit reliability. There is substantial operating experience with both HTS field windings and cryocooling systems. A typical cryocooler and its compressor are shown in Figure 3 with cryocooler heads about 4-in diameter and 14-in tall. A typical compressor is a cube with 24-in side dimension weighing about 260 lbs that could be located remotely from the machine if desired, for example to simplify maintenance access outside the high voltage area. For the prototype, compressors will be cooled with a closed cycle water circuit, and the DSC stator and compressor will be air-cooled.

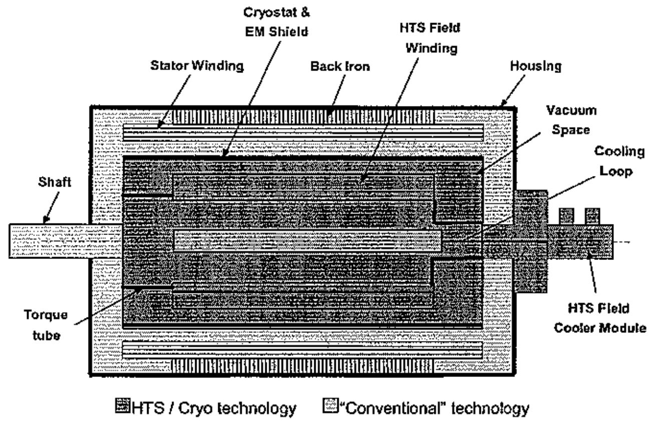

Figure 2: Block diagram of a DSC synchronous machine showing superconducting field winding and its cooling system and conventional armature winding

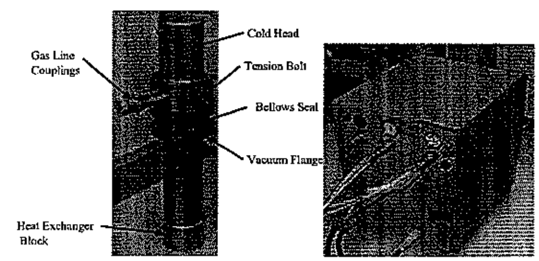

Figure 3: A cryocooler (left) and its compressor (right)

Prototype Details

A prototype DSC presently being manufactured for TVA will have an 8 mega-VAR (MVAR) continuous rating. The DSC is rated for 13.8 kV line to line voltage.. The machine employs a closed loop cryogenic system and a brushless exciter. The DSC is shown in Figure 4. For a short-circuit fault at the machine terminals it can deliver short-circuit current of 8 pu (first peak) and an average of 6.5 pu over the first 5 cycles. This machine will also withstand a 2 pu current loading for up to 60 seconds. The machine is designed to operate in an ambient temperature of -30°C to +40°C in an outdoor installation. The prototype will be locally and remotely monitored for adjusting VAR loading and for its electrical, mechanical and thermal states.

Prior to installation of the prototype a detailed PSS/E model (just developed) will be used in a system simulation to enable optimum setting of the controls and to predict the system behavior with the unit. It is presently planned to operate the prototype in the field for 12 months in a location close to an arc furnace that will provide essentially continuous dynamic operation of the unit.

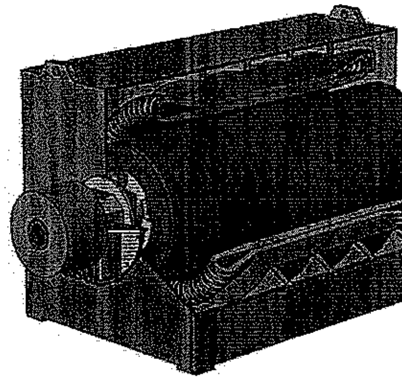

Figure 4: DSC employs superconducting field winding and conventional stator

The DSC is expected to have a life expectancy of over 30 years and should have 50% less losses than conventional synchronous condensers.

The DSC design being developed for TVA is based on a successful demonstration of an HTS superconducting motor[v] (5,000 HP, 1800-RPM) in July 2001. The motor shown in Figure 5 undergoing factory testing was tested up to 5,900 hp (steady-state) in the fall of 2001. Similar confidence in the technology comes from a 70 MVA generator employing low temperature superconductors has been demonstrated[vi] by Hitachi in Japan, where it was demonstrated that it could be operated at 100% of its rated capacity and zero power factor (70 MVARs) without overheating.

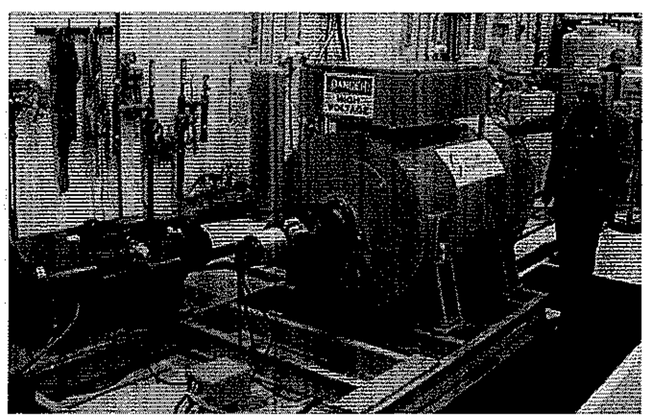

Figure 5: A 5,000 hp, 1800-RPM HTS motor undergoing testing in 2001

The prototype DSC will be housed in an ISO container 8ft wide x 8ft tall x 20ft long. It will weigh 40,000 lbs., which includes the DSC, its support equipment, and the ISO container. It is expected that DSCs would normally be pad mounted but for convenience the TVA prototype will be installed on a trailer. The prototype requires about 30 kW of auxiliary power and this will be obtained from a dry-type transformer connected to the 13.8 kV station bus. Later production units will employ a single cryocooler rather than three as in the prototype.

V. Operational Features

The DSC has low synchronous reactance (x_d = 0.5 pu) which assures dynamic stability within its MVA rating and provides better voltage regulation than a conventional machine. The benefits of lower x_d are summarized below:

- The superconducting machines exhibit lower voltage difference between no-load and full-load operations
- The voltage (E) behind the synchronous reactance is only 1.5 pu at the rated load at zero pf (lagging – over-excited). Since E is proportional to the field current, the DSC will experience a maximum of only 50% field current change as compared to 200% change in a conventional machine.
- E is 50% less than that in a conventional machine.

The sub transient reactance (x_d") of the machine is also low (0.11 pu) which lets the machine provide up to 8 pu first peak current for a terminal short circuit. The major parameters of the machine are shown in Figure 6.

Figure 7 compares the efficiency of the DSC with a conventional synchronous condenser. The HTS field winding eliminates 50% of conventional machine field losses which provides improved efficiency. Additional efficiency is made possible through windage reductions. The DSC also generates very low harmonics. Total Harmonic Distortion (THD) is less than 2.3%.

Synchronous reactance (x_d), pu	0.5
Transient reactance (x_d'), pu	0.22
Sub-transient reactance (x_d"), pu	0.11
Sub-transient reactance (x_q"), pu	0.12
Armature short-circuit time constant (τ_{sc}), s	0.045
D-axis Transient short-circuit time constant (τ_d'), hr	7.31
D-axis Sub-transient short-circuit time constant (τ_d"), s	0.01
D-axis Transient open-circuit time constant (τ_{do}'), hr	15.55
D-axis Sub-transient open-circuit time constant (τ_{do}"), s	0.02
Q-axis Sub-transient short-circuit time constant (τ_q")., s	0.011
Q-axis Sub-transient open-circuit time constant (τ_{qo}"), s	0.043
Armature resistance (r_a), pu	0.007
Inertial constant, s	1.55

Figure 6: Performance parameters of the DSC

Performance

The DSC has no dynamic stability limit within its MVA rating. The machine can run stably without requiring any feedback control for dynamic voltage stabilization. This machine also has a superior dynamic stability during small oscillations and requires no field forcing for damping such oscillations. Figure 8 shows its damping of oscillations following a sudden change of load.

DSC transient stability was studied using a single machine model shown in Figure 9. A 10 MVAR machine was connected to a station bus through a 0.02 pu impedance transformer (assumed model for a 100 MVA station transformer). The substation in turn was connected to a remote bus through two transmission lines with 0.063 pu and 0.19 pu impedances (on a 10 MVA base). Prior to the fault the machine was assumed to be synchronized with the grid. A 3-phase fault was assumed on the high voltage side of the transformer on the 0.063 pu line. Recovery of the DSC from 3-phase faults is shown in Figures 10 through 13. Further studies are underway with the new PSS/E model.

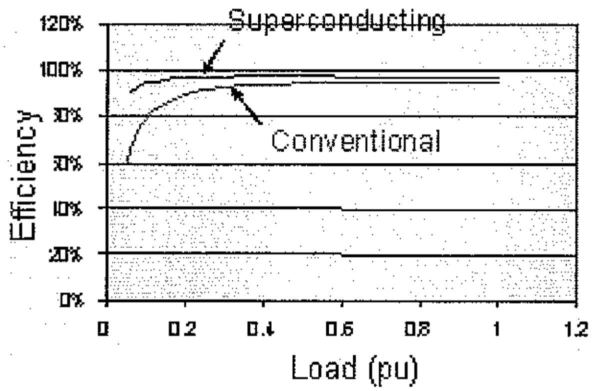

Figure 7: DSC versus conventional machine efficiency

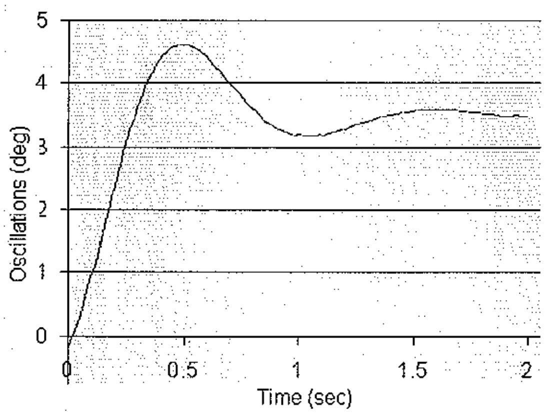

Figure 8: DSC damping of low frequency oscillations following a sudden load change

Figure 10 shows the recovery of a DSC from a fault on the high voltage side of the transformer. The fault duration was 25 cycles. Well-damped rotor oscillations in Figure 10 confirm that this machine can recover from such a fault. The 25 cycle fault duration is much longer than the time needed by a typical protection system to clear a fault.

The current during the fault and recovery periods is shown in Figure 11. In order to obtain a symmetrical fault current waveform the fault was assumed to occur at the peak of armature phase-A voltage. The first peak of the phase A fault current is ~ 8 pu with an average of 6 pu for the first 5 cycles. Fault current settled to about 4 pu for the remainder of the fault period. During a fault the machine slows down, and once the fault is cleared it must draw energy from the grid to recover lost speed. The machine draws about 5 pu current (1st peak) after the fault is cleared and returns to its pre-fault current level in about a second.

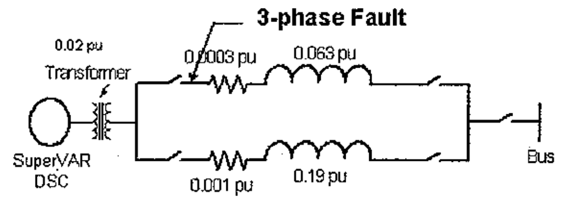

Figure 9: A DSC connected to a remote bus through a dual transmission line for fault studies

Machine terminal voltage during pre-fault, fault and post-fault periods is shown in Figure 12. The machine terminal voltage before the fault is nominal 1.0 pu. In this state the machine was connected to the grid but supplies no current. During the fault machine terminal voltage was depressed to 0.1 pu. Once the fault was cleared, the machine terminal voltage started to recover and achieved its pre-fault level in about a second. This voltage recovery was achieved without any change in the field excitation.

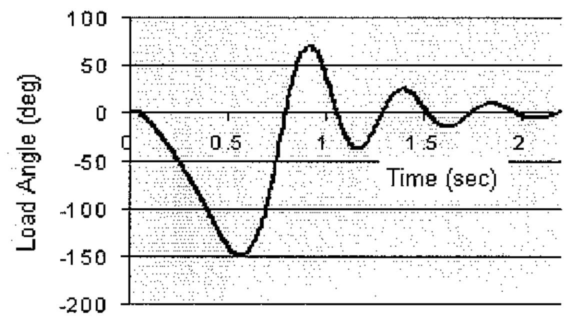

Figure 10: Load angle swing due to a 25 cycle fault on the high voltage side of the transformer

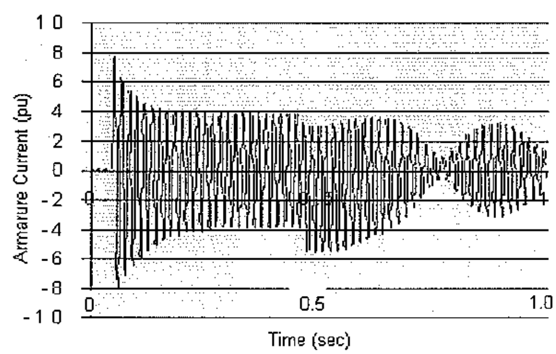

Figure 11: DSC contributes 6 pu current (average) to the fault during a fault and once the fault is cleared, it draws 5 pu current from the grid to make up the lost speed

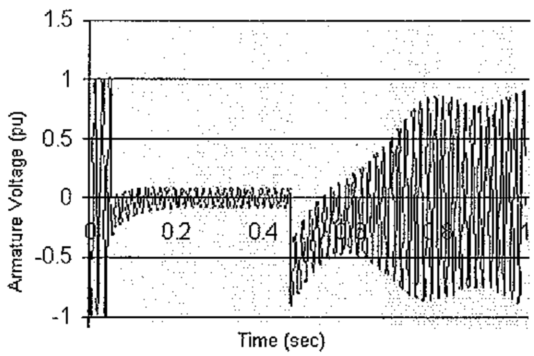

Figure 12: DSC recovers its terminal voltage in about a second without requiring adjustment of the field current

The DSC synchronized with the grid required 1.0 pu field current when delivering no stator current. However, during a fault the armature reaction raised the field current to 2.0 pu. Once the fault was cleared the field current returned to its pre-fault value in about a second. This field current behavior is shown in Figure 13.

These fault studies were also conducted when the machine was delivering its full rating (lagging or leading VARs). Figure 14 summarizes results of these studies. It shows maximum fault duration from which the machine can recover for the following three cases;

- machine initially absorbing VARs (under-excited),
- machine initially delivering no current, and
- machine initially generating VARs (over-excited).

The DSC recovered from a 23 cycle fault while carrying rated MVAR loading – lagging or leading. Its contribution to the fault current (5 cycle average) was higher than 6.6 pu in the over-excited mode as compared to 4.9 pu for the under-excited mode.

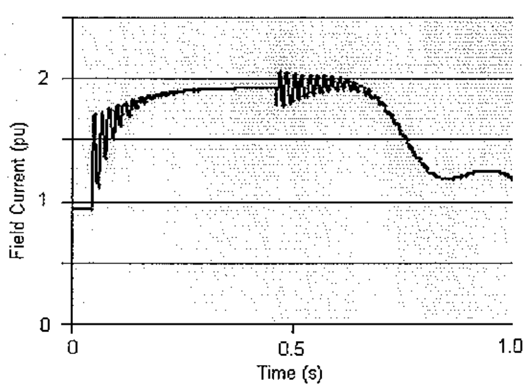

Figure 13: Field current experiences changes due to armature reaction during fault and post-fault periods, but returns to its pre-fault value in about a second

Pre-Fault Condition	MVARS Loading	Fault Duration (Cycles)	Field Current (pu)	Fault Curret (pu) Fist Peak	Fault Curret (pu) Average of first 5-peaks
Under-Excited	-8	23	0.5	7.1	4.9
No current	0	25	1	7.7	5.7
Over-excited	8	23	1.5	8.5	6.6

Figure 14: DSC recovers from 23-cycle faults when delivering rated MVAR (lagging or leading)

If the DSC were required to start direct-on-line, the machine would take about 12 seconds from standstill to achieve rated speed. During this period it would draw a starting current of 5.7 pu., assuming a 0.02pu impedance supply transformer.

If a DSC were subjected to a 3-phase terminal fault that cannot be cleared then it would be necessary to remove the field excitation in order to protect the machine. The machine would otherwise continue to deliver 4 pu current into the fault for a long period of time. In such a situation the DSC protection system must de-excite the field winding. The field current can be reduced to an insignificant value in about 6 seconds limiting total energy deposited in the armature winding to about 2 MJ. This energy is absorbed by the armature with an adiabatic temperature rise of about 10°C.

VI. Conclusions

The innovative design of the DSC is believed to offer a highly efficient low cost alternative for dynamic VAR supply. A prototype unit of 8 MVAR rating is being constructed for TVA, to be followed by 5 10 MVAR units. Units of larger ratings (100-300 MVAr) are expected to be built in the future.

VII. Acknowledgements

The authors acknowledge support of the Tennessee Valley Authority for the development of the DSC. They also acknowledge the support of the AMSC SuperMachines Business Unit engineering and technical staff.

VIII. References

[i] Wollenberg, B.F., 'Transmission system reactive power compensation', Presented at IEEE Power Engineering Society meeting, New York, January 2002

[ii] Miller, T. J. E., 'Reactive Power Control in Electric Systems', John Wiley & Sons, 1982

[iii] SuperVARTM Dynamic Synchronous Condensers, http://www.amsuper.com/html/products/motorsgenerators/quickvar.html

[v] Gamble, B., et al, 'Status of HTS motors', Presented at IEEE Power Engineering Society meeting, Chicago, July 2002

[vi] K. Yamaguchi, et al, '70 MW Class Superconducting Generator Test', IEEE Transactions on Applied Superconductivity, Vol. 9, No. 2, June 1999, page 1209

APPENDIX 11
HYDRO EMAILS – FINANCIAL MODEL INPUT INFORMATION

APPENDIX 11
HYDRO EMAILS – FINANCIAL MODEL INPUT INFORMATION

HYDRO Email No. 1

Hearn, Bill G.

From: AndreaMacDonald@nlh.nl.ca
Sent: Friday, October 26, 2007 12:31 PM
To: Hearn, Bill G.
Cc: NSeymour@nlh.nl.ca
Subject: Fw: Request for Stats for Hardwoods and Stephenville GT's Info

Further info regarding annual forecasted MWhrs. Please see the attached e-mail. Thanks.

Andrea

Andrea MacDonald, P. Eng.
Engineering Services - Mechanical
Newfoundland and Labrador Hydro
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St. John's, NL A1B 4K7
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Phone: 709-737-1205
Fax: 709-737-1900

----- Forwarded by Andrea MacDonald/NLHydro on 10/26/2007 12:58 PM -----

Art Bursey/NLHydro

10/26/2007 11:12 AM

To Andrea MacDonald/NLHydro@NLHydro
cc
Subject Re: Fw: Request for Stats for Hardwoods and Stephenville GT's InfoLink

Andrea,

The forecast average MWhrs loading for the gas turbine for the next 15 years is a very variable number as the future requirements of the gas turbine will change depending upon a number of factors. Our forecast uses a value of 100 MWhrs monthly or 1200 MWhrs yearly. The past five years show the average MWhrs is closer to 300 to 600 MWHrs.

In the forecast the units for energy is giga watt hours (1000 MWhrs). This would make the average 1.2 GWhrs and the past five year average of 0.6 GWHrs, which is approximately 1 GWHrs.

I would recommend that we could use the 1.2 GWhrs or 1200 MWhrs value for both Hardwoods and Stephenville, but make reference that this number could change significantly over the next 15 years.

Thanks,

Art

Art Bursey
Senior System Operations Engineer
System Operations & Customer Services

Newfoundland & Labrador Hydro

Phone (709) 737-1395
Fax (709) 737-1318
e-mail: abursey@nlh.nl.ca

Andrea MacDonald/NLHydro

10/17/2007 09:00 AM

To Art Bursey/NLHydro@NLHydro
cc
Subject Fw: Request for Stats for Hardwoods and Stephenville GT's Info

Hi Art,

For the Stephenville gas turbine facility: if we take the average MWhrs for the last 5 years and use that as the average power every 5 years for the next 15 years, how accurate will this be? Please advise. Thanks.

Andrea

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Engineering Services - Mechanical
Newfoundland and Labrador Hydro
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Phone: 709-737-1205
Fax: 709-737-1900

----- Forwarded by Andrea MacDonald/NLHydro on 10/17/2007 08:57 AM -----

Nelson Seymour/NLHydro

10/16/2007 05:09 PM

To Andrea MacDonald/NLHydro@NLHydro
cc
Subject Re: Fw: Request for Stats for Hardwoods and Stephenville GT's InfoLink

I suggest we use the average for Hwds as you proposed. Not so sure about Svl and the estimated effect that the closing of the paper mill will have. Consult with Art Bursey to get his thoughts.

Nelson

Andrea MacDonald/NLHydro

10/16/2007 10:53 AM

To Nelson Seymour/NLHydro@NLHydro
cc
Subject Fw: Request for Stats for Hardwoods and Stephenville GT's Info

Hi Nelson,

From the attached information from operations, N&G has noted that the MWhrs vary greatly from year to year. Over the 5 year span, the numbers vary from a low of 115 MWhrs in 2004 to a high of 1123 MWhrs in 2003. Should they use the 5 year average for their life cycle analysis for the next 15 years? If not, what do you suggest?

Please advise.
Thanks.

Andrea

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Fax: 709-737-1900

----- Forwarded by Andrea MacDonald/NLHydro on 10/16/2007 10:48 AM -----

Art Bursey/NLHydro

10/15/2007 03:47 PM

To Hughie Ireland/NLHydro@NLHydro
cc Andrea MacDonald/NLHydro@NLHydro, James Wheeler/NLHydro@NLHydro, Nelson Seymour/NLHydro@NLHydro, Steve Carter/NLHydro@NLHydro
Subject Re: Request for Stats for Hardwoods and Stephenville GT's InfoLink

Hughie,

Questions are answered below in red.

Thanks,

Art

Art Bursey
Senior System Operations Engineer
System Operations & Customer Services
Newfoundland & Labrador Hydro

Phone (709) 737-1395
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e-mail: abursey@nlh.nl.ca

Hughie Ireland/NLHydro

10/10/2007 11:25 AM

To Art Bursey/NLHydro@NLHydro
cc Steve Carter/NLHydro@NLHydro, Nelson Seymour/NLHydro@NLHydro, James Wheeler/NLHydro@NLHydro, Andrea MacDonald/NLHydro@NLHydro
Subject Request for Stats for Hardwoods and Stephenville GT's Info

As a result of the ongoing project to complete a condition assessment of HWD and SVL GTs , the consultant N&G have requested the following information with the hope to receive this by the middle of next week in order for them to maintain their current project schedule.

1. Annual MWhrs for each year for the last 5 years for each site.

	Hardwoods Gross MWhrs	Stephenville Gross MWhrs
2002	245	14
2003	1,123	785
2004	115	36
2005	612	194
2006	1,116	706

2. Synchronous Condenser Operating hours last 5 years for each site.

HWD - 15,512.67 hours
SVL - 4,799.20 hours

3. Number of failed starts/stops last five years for each end at each site.(If not by end then by site will be acceptable)

HWD - 7
SVL - 5

4. Number of successful start/stops in last five years for each end at each site. (If not by end then by site will be acceptable)

HWD - 127
SVL- 72

The data above is for the period of January 1, 2002 to Decmeber 31, 2006

Thanks

Hughie

----- Forwarded by Hughie Ireland/NLHydro on 10/10/2007 10:29 AM -----

Andrea MacDonald/NLHydro

10/10/2007 09:38 AM

To James Wheeler/NLHydro@NLHydro
cc Hughie Ireland/NLHydro@NLHydro, Steve Carter/NLHydro@NLHydro, Nelson Seymour/NLHydro@NLHydro
Subject Re: Fw: Hardwoods and Stephenville GT's InfoLink

Hi Jim,

I've reviewed the X drive information. The only thing missing is the semi-annual inspection data for Hardwoods.

New information arising from Aug 21 2007 meeting:

As per the minutes (attached), N&G has requested operational data. Please see item 5 - Operational Data - Hardwoods and Stephenville (pages 8 and 9).

Please let me know whether or not this information is something that we can supply.

Thanks.

Andrea
[attachment "2007-09-05 - Hardwoods GT Kick-off Meeting Minutes.pdf" deleted by Andrea MacDonald/NLHydro]

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Fax: 709-737-1900

James Wheeler/NLHydro

10/09/2007 09:09 PM

To Hughie Ireland/NLHydro@NLHydro
cc Andrea MacDonald/NLHydro@NLHydro, Steve Carter/NLHydro@NLHydro
Subject Re: Fw: Hardwoods and Stephenville GT's InfoLink

I haven't done much with the latest request. I can't access the x: drive where the data was located for Andrea to find and pass on to N & G. I remember populating the fields with all the data we were able to find at the time.

Andrea / Steve:
Could you review the information on the X: drive and determine if there is anything else we can get. Other items like run hours, run mode and start / stops would have to be addressed by the operators in conjunction with maybe the ECC. Steve, would you supply to Andrea whatever information the operators may have logged. There may be other items listed on pages 7 and 8 of Nelson's Sept 5 email.

Hughie:
You are the only person who can supply any information on the financial side.

Jim

Hughie Ireland/NLHydro

10/09/2007 02:55 PM

To James Wheeler/NLHydro@NLHydro
cc
Subject Fw: Hardwoods and Stephenville GT's

Have you done anything with this request ? I will handle the request regarding the budget.

Regards,

Hughie

----- Forwarded by Hughie Ireland/NLHydro on 10/09/2007 02:54 PM -----

Andrea MacDonald/NLHydro

10/05/2007 12:26 PM

To Hughie Ireland/NLHydro@NLHydro
cc Nelson Seymour/NLHydro@NLHydro
Subject Fw: Hardwoods and Stephenville GT's

Hi Hughie,

Please see the attached e-mail. Since Jim is on vacation, perhaps you could assist us with gathering this information? Thanks.

Andrea

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----- Forwarded by Andrea MacDonald/NLHydro on 10/05/2007 12:25 PM -----

Andrea MacDonald/NLHydro

10/02/2007 04:23 PM

To James Wheeler/NLHydro
cc
Subject Hardwoods and Stephenville GT's

Hi Jim,

Please advise whether information will be soon available on the following items or whether no information could be found:

1. Operational Data - Hardwoods and Stephenville. (page 8 of the minutes dated Aug 21, 2007, and e-mailed on Sept 5 2007 by Nelson)

2. Semi-annual inspections for Hardwoods (page 7 of the minutes dated Aug 21, 2007)

Thanks very much.

Andrea

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HYDRO Email No. 2

Hearn, Bill G.

From: AndreaMacDonald@nlh.nl.ca
Sent: Friday, November 02, 2007 9:16 AM
To: Hearn, Bill G.
Subject: Fw: Gas Turbine MVARS for each site
Follow Up Flag: Follow up
Flag Status: Blue
Attachments: GT Loading.xls

Bill,
Please see the attached file for the requested information on gas turbine site MVARS.

Andrea

Andrea MacDonald, P. Eng.
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www.nlh.nl.ca
Phone: 709-737-1205
Fax: 709-737-1900

----- Forwarded by Andrea MacDonald/NLHydro on 11/02/2007 09:43 AM -----

Art Bursey/NLHydro
11/02/2007 09:38 AM

To James Wheeler/NLHydro@NLHydro
cc Andrea MacDonald/NLHydro@NLHydro
Subject Re: Fw: Gas Turbine QuestionLink

Jim,

Please refer to the attached spreadsheet with the daily average and maximum MVAR for Hardwoods and Stephenville Gas Turbines from June 10, 2006 to Nov 1, 2007.

Thanks,

Art

Art Bursey
Senior System Operations Engineer
System Operations & Customer Services
Newfoundland & Labrador Hydro

Phone (709) 737-1395
Fax (709) 737-1318
e-mail: abursey@nlh.nl.ca

James Wheeler/NLHydro

10/31/2007 11:38 AM

To Art Bursey/NLHydro@NLHydro

cc

Subject Fw: Gas Turbine Question

Art:
Could you let me know what the typical daily and maximum MVAR load is for both HWD and SVL GT's.

Thanks
Jim

----- Forwarded by James Wheeler/NLHydro on 10/31/2007 11:06 AM -----

Andrea MacDonald/NLHydro

10/31/2007 10:35 AM

To James Wheeler/NLHydro@NLHydro

cc

Subject Gas Turbine Question

Hi Jim,

Neill and Gunter has one last question regarding the gas turbine sites:

What is a typical (any given day) MVAR load for each of the GT sites. In addition, what would be the Maximum MVAR load experienced at each site.

Please forward this information to be. If it is not possible to obtain, please let me know that as well.

Thanks.

Andrea

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Hardwoods

	Daily Average MVAR	Daily Max MVAR
June 10, 2006	-1.40	15.45
June 11, 2006	-3.27	6.45
June 12, 2006	4.37	15.36
June 13, 2006	-7.77	13.92
June 14, 2006	-4.49	9.51
June 15, 2006	0.17	15.18
June 16, 2006	-3.25	14.19
June 17, 2006	0.38	9.06
June 18, 2006	7.34	18.24
June 19, 2006	3.91	14.55
June 20, 2006	2.33	20.04
June 21, 2006	2.51	15.01
June 22, 2006	1.07	18.96
June 23, 2006	6.37	17.52
June 24, 2006	3.90	16.89
June 25, 2006	-0.02	10.23
June 26, 2006	-4.01	18.33
June 27, 2006	2.42	17.54
June 28, 2006	0.23	12.03
June 29, 2006	-2.45	12.48
June 30, 2006	9.31	23.37
July 1, 2006	2.50	12.84
July 2, 2006	0.04	13.02
July 3, 2006	-0.24	21.39
July 4, 2006	1.32	22.38
July 5, 2006	-3.51	11.76
July 6, 2006	-9.16	9.15
July 7, 2006	-2.26	13.29
July 8, 2006	5.19	11.31
July 9, 2006	0.93	11.76
July 10, 2006	-1.84	10.59
July 11, 2006	10.85	21.30
July 12, 2006	-3.08	9.69
July 13, 2006	3.51	11.58
July 14, 2006	-6.40	4.29
July 15, 2006	-4.96	12.66
July 16, 2006	-9.50	8.34
July 17, 2006	-2.08	10.05
July 18, 2006	1.74	16.17
July 19, 2006	7.07	21.84
July 20, 2006	3.55	11.49
July 21, 2006	2.72	6.18
July 22, 2006	5.15	15.63
July 23, 2006	-1.74	18.33
July 24, 2006	-9.73	-3.17
July 25, 2006	-4.19	6.36
July 26, 2006	-1.01	4.74
July 27, 2006	0.06	0.06
July 28, 2006	0.06	0.06
July 29, 2006	4.09	17.34
July 30, 2006	7.74	18.06
July 31, 2006	2.93	15.64
August 1, 2006	0.13	12.48
August 2, 2006	-2.59	0.15
August 3, 2006	-0.82	15.81
August 4, 2006	1.52	16.44
August 5, 2006	-3.78	7.71
August 6, 2006	-0.70	8.25
August 7, 2006	-8.09	12.75

Stephenville

	Daily Average MVAR	Daily Max MVAR
June 10, 2006	-2.58	1.50
June 11, 2006	-7.13	1.41
June 12, 2006	-6.17	1.41
June 13, 2006	-5.95	-0.30
June 14, 2006	-5.71	-0.30
June 15, 2006	-0.30	-0.30
June 16, 2006	-5.73	-0.30
June 17, 2006	-9.26	1.50
June 18, 2006	-0.30	-0.30
June 19, 2006	-0.30	-0.30
June 20, 2006	-0.30	-0.30
June 21, 2006	-6.13	-0.30
June 22, 2006	-0.30	-0.30
June 23, 2006	-0.30	-0.30
June 24, 2006	-0.30	-0.30
June 25, 2006	-0.30	-0.30
June 26, 2006	-0.30	-0.30
June 27, 2006	-0.30	-0.30
June 28, 2006	-0.30	-0.30
June 29, 2006	-0.30	-0.30
June 30, 2006	-0.30	-0.30
July 1, 2006	-0.96	-0.30
July 2, 2006	-0.30	-0.30
July 3, 2006	-0.30	-0.30
July 4, 2006	-3.07	0.15
July 5, 2006	-0.30	-0.30
July 6, 2006	-0.30	-0.30
July 7, 2006	-0.30	-0.30
July 8, 2006	-0.30	-0.30
July 9, 2006	-0.30	-0.30
July 10, 2006	-0.54	-0.30
July 11, 2006	-5.14	4.02
July 12, 2006	-0.30	-0.30
July 13, 2006	-0.30	-0.30
July 14, 2006	-1.82	1.23
July 15, 2006	-0.30	-0.30
July 16, 2006	-0.30	-0.30
July 17, 2006	-0.30	-0.30
July 18, 2006	-0.34	-0.30
July 19, 2006	-0.45	-0.39
July 20, 2006	-0.45	-0.39
July 21, 2006	-0.45	-0.39
July 22, 2006	-10.53	1.23
July 23, 2006	-0.39	-0.39
July 24, 2006	-0.39	-0.39
July 25, 2006	-0.41	-0.39
July 26, 2006	-0.39	-0.39
July 27, 2006	-0.41	-0.39
July 28, 2006	-0.39	-0.39
July 29, 2006	-4.03	0.24
July 30, 2006	-4.84	0.15
July 31, 2006	-10.58	-5.42
August 1, 2006	-9.24	-1.07
August 2, 2006	-0.42	-0.30
August 3, 2006	-4.82	2.49
August 4, 2006	-3.51	0.06
August 5, 2006	-0.30	-0.30
August 6, 2006	-0.30	-0.30
August 7, 2006	-0.30	-0.30

August 8, 2006	-0.62	11.46
August 9, 2006	-4.25	7.26
August 10, 2006	-0.83	13.20
August 11, 2006	-3.93	9.06
August 12, 2006	-1.29	0.96
August 13, 2006	-4.78	0.06
August 14, 2006	2.63	12.48
August 15, 2006	3.82	12.48
August 16, 2006	3.06	11.85
August 17, 2006	2.31	14.55
August 18, 2006	2.16	13.92
August 19, 2006	6.48	21.30
August 20, 2006	6.53	14.73
August 21, 2006	-3.90	6.54
August 22, 2006	6.18	18.51
August 23, 2006	6.50	15.27
August 24, 2006	-0.35	13.38
August 25, 2006	4.56	19.59
August 26, 2006	-4.56	15.45
August 27, 2006	1.41	11.31
August 28, 2006	0.40	8.97
August 29, 2006	1.92	12.84
August 30, 2006	5.15	14.10
August 31, 2006	6.28	26.61
September 1, 2006	3.87	17.52
September 2, 2006	0.13	9.78
September 3, 2006	1.45	13.29
September 4, 2006	1.43	15.81
September 5, 2006	-5.63	18.87
September 6, 2006	-3.72	6.27
September 7, 2006	5.79	14.82
September 8, 2006	2.13	9.87
September 9, 2006	-1.35	9.60
September 10, 2006	-0.41	9.87
September 11, 2006	5.27	17.25
September 12, 2006	-2.23	8.70
September 13, 2006	-0.99	10.14
September 14, 2006	6.96	13.47
September 15, 2006	-4.48	13.65
September 16, 2006	-2.14	15.36
September 17, 2006	4.54	23.28
September 18, 2006	-2.57	11.67
September 19, 2006	0.38	10.95
September 20, 2006	1.86	6.81
September 21, 2006	-1.11	12.21
September 22, 2006	4.21	11.58
September 23, 2006	-3.47	5.10
September 24, 2006	1.77	11.58
September 25, 2006	-1.29	12.48
September 26, 2006	-4.87	6.00
September 27, 2006	5.11	10.50
September 28, 2006	1.57	13.29
September 29, 2006	1.43	8.34
September 30, 2006	-1.57	10.05
October 1, 2006	-1.93	13.74
October 2, 2006	1.49	11.31
October 3, 2006	0.06	0.06
October 4, 2006	0.06	0.06
October 5, 2006	0.06	0.06
October 6, 2006	0.06	0.06
October 7, 2006	0.06	0.06
October 8, 2006	0.06	0.06
October 9, 2006	0.06	0.06
October 10, 2006	1.55	7.26
October 11, 2006	0.08	0.15
October 12, 2006	0.06	0.06

August 8, 2006	-0.30	-0.30
August 9, 2006	-0.54	-0.30
August 10, 2006	-0.30	-0.30
August 11, 2006	-0.30	-0.30
August 12, 2006	-0.30	-0.30
August 13, 2006	-0.30	-0.30
August 14, 2006	-0.30	-0.30
August 15, 2006	-0.30	-0.30
August 16, 2006	-0.30	-0.30
August 17, 2006	-0.30	-0.30
August 18, 2006	-2.01	0.51
August 19, 2006	-0.30	-0.30
August 20, 2006	-0.30	-0.30
August 21, 2006	-0.30	-0.30
August 22, 2006	-0.30	-0.30
August 23, 2006	-0.30	-0.30
August 24, 2006	-0.30	-0.30
August 25, 2006	-6.20	-0.30
August 26, 2006	-2.77	0.24
August 27, 2006	-7.83	-0.30
August 28, 2006	-4.78	-0.30
August 29, 2006	-0.30	-0.30
August 30, 2006	-0.30	-0.30
August 31, 2006	-3.75	-0.30
September 1, 2006	-5.87	-0.30
September 2, 2006	-0.30	-0.30
September 3, 2006	-0.30	-0.30
September 4, 2006	-16.17	-0.30
September 5, 2006	-9.37	0.78
September 6, 2006	-2.53	-0.30
September 7, 2006	-0.31	-0.30
September 8, 2006	-0.30	-0.30
September 9, 2006	-0.30	-0.30
September 10, 2006	-0.30	-0.30
September 11, 2006	-12.28	-0.30
September 12, 2006	-0.30	-0.30
September 13, 2006	-16.96	-0.30
September 14, 2006	-4.39	1.32
September 15, 2006	-0.30	-0.30
September 16, 2006	-0.30	-0.30
September 17, 2006	-0.30	-0.30
September 18, 2006	-0.30	-0.30
September 19, 2006	-0.30	-0.30
September 20, 2006	-0.30	-0.30
September 21, 2006	-0.30	-0.30
September 22, 2006	-0.30	-0.30
September 23, 2006	-0.30	-0.30
September 24, 2006	-0.30	-0.30
September 25, 2006	-3.71	3.48
September 26, 2006	-0.30	-0.30
September 27, 2006	-0.30	-0.30
September 28, 2006	-0.30	-0.30
September 29, 2006	-3.27	1.50
September 30, 2006	-0.30	-0.30
October 1, 2006	-0.27	-0.21
October 2, 2006	-6.82	-0.26
October 3, 2006	-8.89	-0.30
October 4, 2006	-5.11	5.46
October 5, 2006	-8.02	4.83
October 6, 2006	-6.31	1.14
October 7, 2006	-0.30	-0.30
October 8, 2006	-5.26	-0.30
October 9, 2006	-2.48	0.42
October 10, 2006	-3.95	0.60
October 11, 2006	-0.30	-0.30
October 12, 2006	-0.30	-0.30

October 13, 2006	0.06	0.06
October 14, 2006	0.06	0.06
October 15, 2006	0.06	0.06
October 16, 2006	-1.83	5.91
October 17, 2006	-1.61	2.67
October 18, 2006	-4.09	0.69
October 19, 2006	0.20	14.19
October 20, 2006	0.06	0.06
October 21, 2006	0.06	0.06
October 22, 2006	0.07	0.09
October 23, 2006	-0.16	6.54
October 24, 2006	1.82	19.14
October 25, 2006	-3.96	8.61
October 26, 2006	4.61	14.10
October 27, 2006	-2.49	10.50
October 28, 2006	-1.20	9.26
October 29, 2006	0.24	10.59
October 30, 2006	1.40	5.91
October 31, 2006	0.06	0.06
November 1, 2006	0.06	0.06
November 2, 2006	0.06	0.06
November 3, 2006	0.06	0.06
November 4, 2006	0.06	0.06
November 5, 2006	0.06	0.06
November 6, 2006	0.06	0.15
November 7, 2006	0.06	0.06
November 8, 2006	0.06	0.06
November 9, 2006	0.06	0.06
November 10, 2006	-0.04	14.28
November 11, 2006	-0.95	3.30
November 12, 2006	-2.35	9.51
November 13, 2006	4.95	20.13
November 14, 2006	0.79	13.65
November 15, 2006	-2.64	10.77
November 16, 2006	-3.84	6.09
November 17, 2006	1.64	14.46
November 18, 2006	-1.86	0.06
November 19, 2006	0.06	0.06
November 20, 2006	1.21	12.48
November 21, 2006	5.16	22.20
November 22, 2006	12.34	22.29
November 23, 2006	8.56	23.46
November 24, 2006	-1.67	10.32
November 25, 2006	-0.70	12.12
November 26, 2006	0.49	11.94
November 27, 2006	5.84	20.49
November 28, 2006	6.14	22.20
November 29, 2006	4.39	10.95
November 30, 2006	7.13	22.74
December 1, 2006	2.78	15.90
December 2, 2006	-3.01	17.79
December 3, 2006	0.60	9.87
December 4, 2006	7.29	23.91
December 5, 2006	2.38	15.90
December 6, 2006	2.74	24.09
December 7, 2006	1.97	27.59
December 8, 2006	0.06	0.06
December 9, 2006	3.08	14.91
December 10, 2006	-0.01	0.15
December 11, 2006	0.63	9.15
December 12, 2006	1.44	15.99
December 13, 2006	5.39	31.10
December 14, 2006	7.67	22.02
December 15, 2006	-0.92	14.19
December 16, 2006	-1.46	15.09
December 17, 2006	2.37	17.34

October 13, 2006	-0.30	-0.30
October 14, 2006	-0.31	-0.30
October 15, 2006	-10.28	-0.30
October 16, 2006	-7.01	29.03
October 17, 2006	1.28	32.81
October 18, 2006	-2.19	24.90
October 19, 2006	2.34	7.53
October 20, 2006	2.34	35.87
October 21, 2006	-4.49	-0.30
October 22, 2006	-0.30	-0.30
October 23, 2006	-0.75	-0.30
October 24, 2006	-11.25	1.95
October 25, 2006	-3.84	4.29
October 26, 2006	-6.85	-0.30
October 27, 2006	-7.90	1.14
October 28, 2006	-16.82	-0.30
October 29, 2006	-9.45	-0.30
October 30, 2006	-12.12	-3.44
October 31, 2006	-14.47	-7.76
November 1, 2006	-7.03	4.74
November 2, 2006	-7.22	9.60
November 3, 2006	-10.54	2.22
November 4, 2006	-9.08	-0.30
November 5, 2006	-4.88	0.15
November 6, 2006	-0.33	-0.21
November 7, 2006	-3.00	8.25
November 8, 2006	-5.64	6.00
November 9, 2006	-5.50	9.33
November 10, 2006	-0.55	-0.30
November 11, 2006	-5.86	-0.30
November 12, 2006	-7.97	-0.30
November 13, 2006	-9.69	1.86
November 14, 2006	-1.45	-0.30
November 15, 2006	-8.86	7.08
November 16, 2006	-20.86	-11.81
November 17, 2006	-20.95	-18.29
November 18, 2006	-32.53	71.95
November 19, 2006	-19.80	-17.48
November 20, 2006	-15.81	-6.32
November 21, 2006	-20.59	-17.84
November 22, 2006	-18.29	-10.82
November 23, 2006	-16.74	-12.98
November 24, 2006	-19.84	-17.66
November 25, 2006	-17.10	-5.06
November 26, 2006	-10.88	0.15
November 27, 2006	-17.90	0.51
November 28, 2006	-6.71	2.67
November 29, 2006	-14.76	1.23
November 30, 2006	-14.32	0.15
December 1, 2006	-15.06	-0.93
December 2, 2006	-15.55	-11.00
December 3, 2006	-16.54	-11.72
December 4, 2006	-15.13	-11.54
December 5, 2006	-17.50	-2.37
December 6, 2006	-10.75	0.15
December 7, 2006	-13.00	0.15
December 8, 2006	-14.10	3.03
December 9, 2006	-8.35	3.57
December 10, 2006	-14.83	-11.00
December 11, 2006	-15.80	-12.08
December 12, 2006	-14.67	-11.18
December 13, 2006	-11.37	-4.88
December 14, 2006	-20.67	-18.38
December 15, 2006	-18.67	-13.88
December 16, 2006	-16.34	-11.72
December 17, 2006	-18.70	-15.50

December 18, 2006	7.12	18.69
December 19, 2006	7.41	24.45
December 20, 2006	4.26	16.35
December 21, 2006	6.29	21.48
December 22, 2006	3.07	13.47
December 23, 2006	8.43	20.13
December 24, 2006	4.05	14.10
December 25, 2006	0.02	0.06
December 26, 2006	2.11	12.93
December 27, 2006	3.09	20.94
December 28, 2006	9.99	26.52
December 29, 2006	14.95	31.64
December 30, 2006	13.98	29.48
December 31, 2006	8.01	27.05
January 1, 2007	7.01	19.68
January 2, 2007	8.01	17.88
January 3, 2007	9.77	27.59
January 4, 2007	1.77	16.08
January 5, 2007	1.95	15.54
January 6, 2007	1.38	13.20
January 7, 2007	-1.88	4.56
January 8, 2007	-0.07	9.33
January 9, 2007	3.00	20.76
January 10, 2007	10.22	20.04
January 11, 2007	11.77	22.20
January 12, 2007	11.18	20.85
January 13, 2007	2.36	6.90
January 14, 2007	9.66	21.84
January 15, 2007	9.04	26.79
January 16, 2007	6.37	16.98
January 17, 2007	10.95	24.99
January 18, 2007	9.48	18.51
January 19, 2007	2.91	16.17
January 20, 2007	2.99	16.44
January 21, 2007	1.20	10.77
January 22, 2007	6.63	28.76
January 23, 2007	4.71	19.50
January 24, 2007	1.35	4.74
January 25, 2007	0.93	6.09
January 26, 2007	4.25	23.46
January 27, 2007	10.09	24.72
January 28, 2007	2.51	8.61
January 29, 2007	6.73	28.22
January 30, 2007	11.76	28.94
January 31, 2007	5.28	21.30
February 1, 2007	8.90	23.28
February 2, 2007	-0.89	1.77
February 3, 2007	-0.03	0.06
February 4, 2007	3.72	20.31
February 5, 2007	2.43	16.44
February 6, 2007	3.97	19.86
February 7, 2007	2.50	13.02
February 8, 2007	4.27	15.63
February 9, 2007	2.16	5.73
February 10, 2007	4.03	13.92
February 11, 2007	5.75	22.29
February 12, 2007	4.08	17.79
February 13, 2007	7.70	14.46
February 14, 2007	10.13	17.79
February 15, 2007	11.18	21.03
February 16, 2007	1.37	5.55
February 17, 2007	3.06	17.79
February 18, 2007	4.86	20.04
February 19, 2007	8.47	23.73
February 20, 2007	6.36	17.70
February 21, 2007	3.34	18.24

December 18, 2006	-17.47	-12.98
December 19, 2006	-17.29	-13.34
December 20, 2006	-15.89	-6.14
December 21, 2006	-14.16	-10.28
December 22, 2006	-14.29	-10.10
December 23, 2006	-8.79	-1.83
December 24, 2006	-15.32	-4.70
December 25, 2006	-20.41	-17.12
December 26, 2006	-18.67	-9.74
December 27, 2006	-15.39	-6.50
December 28, 2006	-10.03	1.05
December 29, 2006	0.16	4.65
December 30, 2006	-5.01	0.15
December 31, 2006	0.15	0.15
January 1, 2007	0.15	0.15
January 2, 2007	0.15	0.15
January 3, 2007	-4.96	0.15
January 4, 2007	-2.29	0.51
January 5, 2007	0.15	0.15
January 6, 2007	0.15	0.15
January 7, 2007	-6.26	0.15
January 8, 2007	-7.16	0.15
January 9, 2007	-9.21	0.15
January 10, 2007	0.15	0.15
January 11, 2007	-1.19	0.15
January 12, 2007	0.15	0.15
January 13, 2007	0.15	0.15
January 14, 2007	0.15	0.15
January 15, 2007	0.15	0.15
January 16, 2007	0.10	0.15
January 17, 2007	0.15	0.15
January 18, 2007	0.15	0.15
January 19, 2007	0.15	0.15
January 20, 2007	0.15	0.15
January 21, 2007	0.15	0.15
January 22, 2007	0.15	0.15
January 23, 2007	0.15	0.15
January 24, 2007	-0.11	4.65
January 25, 2007	0.02	0.15
January 26, 2007	0.07	0.15
January 27, 2007	0.15	0.15
January 28, 2007	0.15	0.15
January 29, 2007	0.15	0.15
January 30, 2007	0.15	0.15
January 31, 2007	0.15	0.15
February 1, 2007	0.15	0.15
February 2, 2007	0.09	0.15
February 3, 2007	0.15	0.15
February 4, 2007	0.15	0.15
February 5, 2007	0.15	0.15
February 6, 2007	0.15	0.15
February 7, 2007	0.15	0.15
February 8, 2007	0.14	0.15
February 9, 2007	0.15	0.15
February 10, 2007	-1.34	0.15
February 11, 2007	-3.13	0.15
February 12, 2007	-0.15	0.33
February 13, 2007	-4.91	0.87
February 14, 2007	-0.33	0.15
February 15, 2007	-2.96	0.15
February 16, 2007	0.15	0.15
February 17, 2007	0.15	0.15
February 18, 2007	0.15	0.15
February 19, 2007	0.15	0.15
February 20, 2007	0.15	0.15
February 21, 2007	0.15	0.15

February 22, 2007	1.09	11.58
February 23, 2007	5.84	19.86
February 24, 2007	4.62	18.42
February 25, 2007	-1.71	4.74
February 26, 2007	-1.97	8.43
February 27, 2007	3.26	19.05
February 28, 2007	3.94	22.20
March 1, 2007	7.81	26.97
March 2, 2007	4.01	17.43
March 3, 2007	5.32	20.04
March 4, 2007	0.06	0.06
March 5, 2007	6.28	19.05
March 6, 2007	-0.86	12.93
March 7, 2007	14.53	29.39
March 8, 2007	9.00	28.04
March 9, 2007	14.33	27.59
March 10, 2007	2.17	9.69
March 11, 2007	-0.04	0.06
March 12, 2007	4.99	21.57
March 13, 2007	0.52	6.63
March 14, 2007	-0.09	1.32
March 15, 2007	0.06	0.06
March 16, 2007	0.06	0.06
March 17, 2007	3.01	21.39
March 18, 2007	0.06	0.06
March 19, 2007	0.06	0.06
March 20, 2007	0.62	10.68
March 21, 2007	1.56	12.84
March 22, 2007	6.17	26.52
March 23, 2007	1.05	11.49
March 24, 2007	0.14	2.49
March 25, 2007	0.90	10.23
March 26, 2007	7.71	15.00
March 27, 2007	1.33	4.74
March 28, 2007	1.85	14.28
March 29, 2007	0.90	10.59
March 30, 2007	0.06	0.06
March 31, 2007	0.06	0.06
April 1, 2007	3.92	20.67
April 2, 2007	1.97	23.46
April 3, 2007	1.19	5.37
April 4, 2007	4.44	10.68
April 5, 2007	0.06	0.06
April 6, 2007	0.06	0.06
April 7, 2007	0.06	0.06
April 8, 2007	0.06	0.06
April 9, 2007	0.06	0.06
April 10, 2007	1.84	8.88
April 11, 2007	0.06	1.23
April 12, 2007	-0.95	6.36
April 13, 2007	0.06	0.06
April 14, 2007	3.57	21.57
April 15, 2007	0.77	9.87
April 16, 2007	2.98	16.17
April 17, 2007	3.30	23.10
April 18, 2007	0.82	4.20
April 19, 2007	7.85	15.81
April 20, 2007	2.01	16.71
April 21, 2007	0.06	0.06
April 22, 2007	0.06	0.06
April 23, 2007	0.26	4.56
April 24, 2007	0.06	0.06
April 25, 2007	0.06	0.06
April 26, 2007	0.06	0.06
April 27, 2007	1.21	17.25
April 28, 2007	4.79	17.97

February 22, 2007	0.15	0.15
February 23, 2007	0.15	0.15
February 24, 2007	0.15	0.15
February 25, 2007	0.15	0.15
February 26, 2007	0.15	0.15
February 27, 2007	0.15	0.15
February 28, 2007	0.15	0.15
March 1, 2007	0.15	0.15
March 2, 2007	0.15	0.15
March 3, 2007	0.15	0.15
March 4, 2007	0.15	0.15
March 5, 2007	-0.04	0.15
March 6, 2007	0.20	1.41
March 7, 2007	0.15	0.15
March 8, 2007	-0.12	0.15
March 9, 2007	0.18	1.77
March 10, 2007	0.15	0.15
March 11, 2007	0.15	0.15
March 12, 2007	0.15	0.15
March 13, 2007	-0.76	0.51
March 14, 2007	0.12	0.16
March 15, 2007	0.15	0.15
March 16, 2007	0.15	0.15
March 17, 2007	1.16	8.43
March 18, 2007	0.15	0.15
March 19, 2007	0.15	0.15
March 20, 2007	0.15	0.15
March 21, 2007	0.15	0.15
March 22, 2007	0.15	0.15
March 23, 2007	-0.76	0.15
March 24, 2007	-6.32	0.15
March 25, 2007	-4.14	1.95
March 26, 2007	-4.87	2.67
March 27, 2007	0.15	0.15
March 28, 2007	-3.98	0.15
March 29, 2007	-1.18	0.15
March 30, 2007	0.15	0.15
March 31, 2007	0.15	0.15
April 1, 2007	0.15	0.15
April 2, 2007	-0.09	0.15
April 3, 2007	0.14	0.15
April 4, 2007	-0.16	1.59
April 5, 2007	0.15	0.15
April 6, 2007	0.09	0.15
April 7, 2007	-1.28	1.23
April 8, 2007	0.15	0.15
April 9, 2007	0.18	3.39
April 10, 2007	-0.77	1.59
April 11, 2007	-2.50	0.15
April 12, 2007	-7.66	0.15
April 13, 2007	-0.34	0.15
April 14, 2007	0.15	0.15
April 15, 2007	0.15	0.15
April 16, 2007	0.09	0.15
April 17, 2007	0.21	0.51
April 18, 2007	0.15	0.15
April 19, 2007	0.09	0.15
April 20, 2007	-0.02	0.07
April 21, 2007	-4.26	0.15
April 22, 2007	-3.82	1.95
April 23, 2007	0.15	0.15
April 24, 2007	0.09	0.15
April 25, 2007	0.11	0.15
April 26, 2007	0.15	0.15
April 27, 2007	-0.45	0.15
April 28, 2007	-0.72	0.15

April 29, 2007	0.09	0.15
April 30, 2007	0.06	0.06
May 1, 2007	0.06	0.06
May 2, 2007	0.06	0.06
May 3, 2007	0.06	0.06
May 4, 2007	0.06	0.06
May 5, 2007	0.06	0.06
May 6, 2007	-0.06	0.06
May 7, 2007	0.06	0.06
May 8, 2007	0.06	0.06
May 9, 2007	0.06	0.06
May 10, 2007	0.06	0.06
May 11, 2007	0.06	0.06
May 12, 2007	0.06	0.06
May 13, 2007	0.06	0.06
May 14, 2007	0.06	0.06
May 15, 2007	0.06	0.06
May 16, 2007	0.06	0.06
May 17, 2007	0.06	0.06
May 18, 2007	0.06	0.06
May 19, 2007	0.06	0.06
May 20, 2007	0.06	0.06
May 21, 2007	0.04	0.06
May 22, 2007	0.05	0.06
May 23, 2007	0.06	0.06
May 24, 2007	0.06	0.06
May 25, 2007	0.06	0.06
May 26, 2007	0.06	0.06
May 27, 2007	0.06	0.06
May 28, 2007	0.06	0.06
May 29, 2007	0.06	0.06
May 30, 2007	0.06	0.06
May 31, 2007	-0.17	0.06
June 1, 2007	0.05	0.06
June 2, 2007	0.03	0.06
June 3, 2007	0.06	0.06
June 4, 2007	0.06	0.06
June 5, 2007	0.06	0.06
June 6, 2007	0.06	0.06
June 7, 2007	0.04	0.06
June 8, 2007	0.06	0.06
June 9, 2007	0.06	0.06
June 10, 2007	0.06	0.06
June 11, 2007	1.43	15.09
June 12, 2007	1.24	13.33
June 13, 2007	0.06	0.06
June 14, 2007	0.06	0.06
June 15, 2007	0.06	0.06
June 16, 2007	0.06	0.06
June 17, 2007	0.05	0.06
June 18, 2007	0.05	0.06
June 19, 2007	-0.07	16.71
June 20, 2007	-0.02	0.06
June 21, 2007	0.06	0.06
June 22, 2007	0.03	0.06
June 23, 2007	3.12	7.98
June 24, 2007	1.72	12.93
June 25, 2007	0.06	0.06
June 26, 2007	0.06	0.06
June 27, 2007	0.06	0.06
June 28, 2007	1.01	6.90
June 29, 2007	-1.13	2.58
June 30, 2007	-0.31	7.62
July 1, 2007	-4.21	2.04
July 2, 2007	1.92	18.78
July 3, 2007	7.36	14.28

April 29, 2007	-5.72	1.41
April 30, 2007	-7.56	0.15
May 1, 2007	-8.34	0.15
May 2, 2007	-3.89	0.15
May 3, 2007	-3.04	0.15
May 4, 2007	-2.71	0.15
May 5, 2007	0.15	0.15
May 6, 2007	-5.00	0.33
May 7, 2007	0.15	0.15
May 8, 2007	-2.84	0.15
May 9, 2007	-3.70	0.15
May 10, 2007	-5.24	0.15
May 11, 2007	-5.40	0.15
May 12, 2007	-6.62	1.77
May 13, 2007	-12.11	0.51
May 14, 2007	-9.22	-1.29
May 15, 2007	-14.38	-0.21
May 16, 2007	0.12	0.15
May 17, 2007	0.15	0.15
May 18, 2007	0.04	0.15
May 19, 2007	-5.40	1.77
May 20, 2007	-7.72	0.13
May 21, 2007	-5.79	0.15
May 22, 2007	-4.17	0.15
May 23, 2007	0.15	0.15
May 24, 2007	-5.37	0.15
May 25, 2007	-7.39	0.15
May 26, 2007	-9.28	0.15
May 27, 2007	-9.90	0.15
May 28, 2007	-6.19	0.15
May 29, 2007	-5.65	0.15
May 30, 2007	0.15	0.15
May 31, 2007	-1.85	0.15
June 1, 2007	-3.70	0.15
June 2, 2007	-7.32	0.51
June 3, 2007	0.15	0.15
June 4, 2007	-3.55	0.15
June 5, 2007	-2.71	0.15
June 6, 2007	-14.80	0.15
June 7, 2007	-13.68	-9.20
June 8, 2007	-7.95	1.59
June 9, 2007	-8.19	2.31
June 10, 2007	-12.59	-5.24
June 11, 2007	-10.79	3.03
June 12, 2007	-9.53	-2.37
June 13, 2007	-7.56	0.15
June 14, 2007	-3.84	0.15
June 15, 2007	-10.89	1.77
June 16, 2007	-17.54	-15.32
June 17, 2007	-16.04	-11.90
June 18, 2007	-8.77	0.15
June 19, 2007	-18.41	-15.32
June 20, 2007	-11.68	-4.88
June 21, 2007	-12.22	-8.30
June 22, 2007	-10.62	-5.78
June 23, 2007	-13.22	-10.82
June 24, 2007	-11.35	-8.12
June 25, 2007	-14.46	-5.96
June 26, 2007	-10.37	0.51
June 27, 2007	-18.84	-15.68
June 28, 2007	-17.26	-14.60
June 29, 2007	-12.52	0.15
June 30, 2007	-16.25	-13.35
July 1, 2007	-17.12	-10.64
July 2, 2007	-15.85	-11.00
July 3, 2007	-11.11	-6.86

July 4, 2007	4.49	13.38
July 5, 2007	-0.09	10.41
July 6, 2007	-0.91	17.25
July 7, 2007	-2.33	3.93
July 8, 2007	-4.74	3.39
July 9, 2007	-1.22	5.55
July 10, 2007	3.24	14.64
July 11, 2007	-1.67	1.77
July 12, 2007	-1.53	7.62
July 13, 2007	-3.57	6.18
July 14, 2007	-6.33	3.12
July 15, 2007	-2.66	6.90
July 16, 2007	-0.95	12.03
July 17, 2007	2.38	11.67
July 18, 2007	3.36	8.52
July 19, 2007	2.26	8.97
July 20, 2007	-0.32	0.06
July 21, 2007	-1.15	5.28
July 22, 2007	0.92	6.45
July 23, 2007	-0.93	6.54
July 24, 2007	0.32	12.48
July 25, 2007	1.96	10.05
July 26, 2007	3.18	7.80
July 27, 2007	-2.78	1.77
July 28, 2007	-2.03	6.72
July 29, 2007	-0.40	14.73
July 30, 2007	7.27	23.46
July 31, 2007	3.66	19.68
August 1, 2007	-0.29	15.27
August 2, 2007	-2.61	13.74
August 3, 2007	-1.00	14.19
August 4, 2007	0.97	18.33
August 5, 2007	3.03	14.82
August 6, 2007	5.60	18.96
August 7, 2007	1.82	5.91
August 8, 2007	2.67	14.10
August 9, 2007	8.81	19.41
August 10, 2007	-2.13	4.65
August 11, 2007	6.11	23.55
August 12, 2007	-2.11	6.81
August 13, 2007	-6.43	17.52
August 14, 2007	0.94	12.21
August 15, 2007	0.58	10.86
August 16, 2007	0.09	11.04
August 17, 2007	2.84	21.12
August 18, 2007	-7.73	9.15
August 19, 2007	-0.88	11.13
August 20, 2007	2.46	16.17
August 21, 2007	-5.17	11.67
August 22, 2007	-3.26	10.23
August 23, 2007	-2.55	13.74
August 24, 2007	-1.80	7.35
August 25, 2007	-1.11	8.79
August 26, 2007	0.61	11.31
August 27, 2007	7.14	20.22
August 28, 2007	7.73	23.55
August 29, 2007	1.05	10.77
August 30, 2007	-3.19	14.73
August 31, 2007	2.87	17.25
September 1, 2007	1.51	13.02
September 2, 2007	2.43	13.20
September 3, 2007	-6.39	4.06
September 4, 2007	-2.97	13.29
September 5, 2007	1.63	20.22
September 6, 2007	-4.24	17.52
September 7, 2007	0.70	12.82

July 4, 2007	-17.35	-15.14
July 5, 2007	-15.52	-12.26
July 6, 2007	-16.05	-11.54
July 7, 2007	-14.07	-2.55
July 8, 2007	-9.70	-3.26
July 9, 2007	-9.04	-6.68
July 10, 2007	-11.91	-5.60
July 11, 2007	-8.71	0.69
July 12, 2007	-18.78	-14.42
July 13, 2007	-18.94	-13.88
July 14, 2007	-18.71	-16.40
July 15, 2007	-17.21	-12.80
July 16, 2007	-12.28	-3.80
July 17, 2007	-9.98	5.73
July 18, 2007	-17.02	-8.66
July 19, 2007	-13.45	-0.75
July 20, 2007	-13.69	-7.40
July 21, 2007	-14.68	-9.74
July 22, 2007	-19.14	-15.14
July 23, 2007	-18.67	-13.88
July 24, 2007	-17.09	-12.98
July 25, 2007	-11.89	0.15
July 26, 2007	-17.23	-12.80
July 27, 2007	-17.53	-14.06
July 28, 2007	-18.43	-15.86
July 29, 2007	-17.02	-12.44
July 30, 2007	-16.56	-13.70
July 31, 2007	-15.97	-13.16
August 1, 2007	-15.66	-11.18
August 2, 2007	-17.69	-13.88
August 3, 2007	-17.29	-14.78
August 4, 2007	-18.08	-8.12
August 5, 2007	-19.51	-10.82
August 6, 2007	-18.67	-14.24
August 7, 2007	-15.70	0.15
August 8, 2007	-15.76	-10.64
August 9, 2007	-18.45	-14.06
August 10, 2007	-16.56	0.15
August 11, 2007	-15.40	-10.82
August 12, 2007	-19.09	-16.94
August 13, 2007	-18.29	-15.32
August 14, 2007	-17.78	-14.06
August 15, 2007	-19.36	-15.86
August 16, 2007	-20.09	-17.66
August 17, 2007	-20.09	-17.30
August 18, 2007	-19.56	-18.02
August 19, 2007	-20.04	-18.92
August 20, 2007	-19.07	-16.94
August 21, 2007	-19.41	-17.48
August 22, 2007	-8.54	0.15
August 23, 2007	-7.86	1.41
August 24, 2007	-4.87	0.15
August 25, 2007	-10.00	-8.66
August 26, 2007	-10.07	-7.40
August 27, 2007	-6.68	0.15
August 28, 2007	-7.55	0.15
August 29, 2007	-3.30	0.15
August 30, 2007	0.15	0.15
August 31, 2007	-2.38	0.15
September 1, 2007	-17.19	-15.50
September 2, 2007	-17.16	-16.22
September 3, 2007	-18.27	-13.52
September 4, 2007	-17.55	-13.52
September 5, 2007	-17.21	-15.50
September 6, 2007	-16.35	-13.88
September 7, 2007	-17.14	-14.78

September 8, 2007	-1.86	9.69
September 9, 2007	5.06	12.75
September 10, 2007	2.73	8.88
September 11, 2007	1.90	14.01
September 12, 2007	-1.91	13.92
September 13, 2007	-0.54	2.94
September 14, 2007	0.22	4.02
September 15, 2007	10.10	18.78
September 16, 2007	-1.16	14.55
September 17, 2007	3.13	10.23
September 18, 2007	4.12	17.16
September 19, 2007	1.43	12.12
September 20, 2007	4.03	15.09
September 21, 2007	-0.11	11.22
September 22, 2007	-0.63	6.09
September 23, 2007	-2.52	11.04
September 24, 2007	-5.84	2.13
September 25, 2007	-2.87	8.34
September 26, 2007	0.01	8.07
September 27, 2007	3.87	12.03
September 28, 2007	1.43	13.20
September 29, 2007	-4.31	6.90
September 30, 2007	-1.35	9.69
October 1, 2007	2.21	14.55
October 2, 2007	-0.21	8.20
October 3, 2007	-5.72	3.21
October 4, 2007	-0.31	10.59
October 5, 2007	4.38	7.80
October 6, 2007	4.45	18.60
October 7, 2007	6.71	12.39
October 8, 2007	1.52	11.22
October 9, 2007	5.54	13.29
October 10, 2007	2.08	16.98
October 11, 2007	-1.11	4.75
October 12, 2007	-0.12	3.66
October 13, 2007	4.18	9.96
October 14, 2007	-1.06	6.90
October 15, 2007	0.13	0.51
October 16, 2007	0.06	0.06
October 17, 2007	0.06	0.06
October 18, 2007	-2.51	14.55
October 19, 2007	-2.24	11.49
October 20, 2007	1.41	13.47
October 21, 2007	-1.67	12.57
October 22, 2007	-4.34	2.76
October 23, 2007	-4.73	0.87
October 24, 2007	2.86	7.98
October 25, 2007	1.39	6.90
October 26, 2007	-0.22	4.20
October 27, 2007	0.82	9.33
October 28, 2007	0.45	9.42
October 29, 2007	0.19	8.25
October 30, 2007	3.20	7.71
October 31, 2007	2.20	9.24
November 1, 2007	3.32	11.31

September 8, 2007	-14.13	-10.46
September 9, 2007	-14.26	-12.44
September 10, 2007	-15.05	-8.48
September 11, 2007	-12.61	-7.94
September 12, 2007	-14.91	-11.90
September 13, 2007	-13.52	-10.46
September 14, 2007	-12.87	-8.66
September 15, 2007	-14.31	-12.26
September 16, 2007	-13.34	-11.00
September 17, 2007	-12.74	-10.64
September 18, 2007	-15.05	-13.23
September 19, 2007	-16.03	-13.70
September 20, 2007	-19.94	-17.66
September 21, 2007	-20.39	-19.28
September 22, 2007	-19.91	-18.74
September 23, 2007	-20.21	-18.38
September 24, 2007	-19.98	-18.02
September 25, 2007	-14.85	8.43
September 26, 2007	-15.06	0.15
September 27, 2007	-13.48	-11.36
September 28, 2007	-14.62	-9.92
September 29, 2007	-16.45	-12.80
September 30, 2007	-16.04	-14.60
October 1, 2007	-16.11	-14.06
October 2, 2007	-16.30	-12.80
October 3, 2007	-17.58	-15.68
October 4, 2007	-20.60	-18.02
October 5, 2007	-20.54	-20.39
October 6, 2007	-20.49	-19.64
October 7, 2007	-20.65	-15.50
October 8, 2007	-20.46	-19.64
October 9, 2007	-20.73	-19.46
October 10, 2007	-20.77	-20.00
October 11, 2007	-20.62	-18.38
October 12, 2007	-20.51	-19.82
October 13, 2007	-20.91	-20.18
October 14, 2007	-20.57	-19.46
October 15, 2007	-20.40	-19.64
October 16, 2007	-8.72	1.41
October 17, 2007	-10.52	-6.50
October 18, 2007	-6.03	7.35
October 19, 2007	-16.65	-13.52
October 20, 2007	-13.54	-10.82
October 21, 2007	-20.29	-14.42
October 22, 2007	-20.58	-17.30
October 23, 2007	-11.18	0.87
October 24, 2007	-16.60	-13.52
October 25, 2007	-20.53	-18.56
October 26, 2007	-20.65	-18.20
October 27, 2007	-16.30	-0.75
October 28, 2007	-2.78	2.31
October 29, 2007	-5.13	0.15
October 30, 2007	-5.55	3.57
October 31, 2007	0.06	0.15
November 1, 2007	-2.52	7.89

HYDRO Email No. 3

Hearn, Bill G.

From: AndreaMacDonald@nlh.nl.ca
Sent: Wednesday, October 24, 2007 8:25 AM
To: Hearn, Bill G.
Subject: Fw: HWD and SVL GT O&M Cost 2002 to 2006
Attachments: HWD and SVL GT O & M Cost 2002 to 2006.xls

More information for the gas turbine project. Please see the attached e-mail and spreadsheet.

Andrea

Andrea MacDonald, P. Eng.
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www.nlh.nl.ca
Phone: 709-737-1205
Fax: 709-737-1900

----- Forwarded by Andrea MacDonald/NLHydro on 10/24/2007 08:53 AM -----

Hughie Ireland/NLHydro

10/24/2007 12:40 AM

To Andrea MacDonald/NLHydro@NLHydro
cc
Subject HWD and SVL GT O&M Cost 2002 to 2006

Andrea, I meant to send this sometime ago... Hope it is not too late .

Attached is a breakdown of the O&M cost for HWD and SVL gas Turbines. Please note this does not include fuel cost.

HWD and SVLGT O&M Cost 2002 to 2006
(Excluding Fuel Cost)

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

HYDRO Email No. 4

Hearn, Bill G.

From: AndreaMacDonald@nlh.nl.ca
Sent: Thursday, October 11, 2007 10:41 AM
To: Hearn, Bill G.
Subject: Fuel Prices - Stephenville and Hardwoods
Attachments: Fuel Prices - Hardwoods and Stephenville - Oct 10 2007.xls

Hi Bill,
Please see the attached file for the fuel prices for Stephenville and Hardwoods gas turbine facilities. This completes # 6 (item 4 - Annual Projected Fuel Costs Going Forward) of the Aug 21, 2007 minutes.
If you have any questions please let me know.
Thanks.
Andrea

Andrea MacDonald, P. Eng.
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#2 Gas Turbine Fuel Price Forecast for NLH Hardwoods and Stephenville Sites

(Nominal Dollars)

	Hardwoods ($Cdn/l)	Stephenville ($Cdn/l)
2008	0.624	0.686
2009	0.552	0.613
2010	0.557	0.619
2011	0.578	0.640
2012	0.606	0.668
2013	0.631	0.694
2014	0.666	0.730
2015	0.686	0.752
2016	0.721	0.788
2017	0.751	0.820
2018	0.786	0.856
2019	0.816	0.888
2020	0.847	0.919
2021	0.867	0.941
2022	0.882	0.957
2023	0.902	0.979
2024	0.922	1.001
2025	0.942	1.022
2026	0.957	1.039
2027	0.977	1.061
2028	1.002	1.088
2029	1.022	1.109
2030	1.042	1.131
2031	1.062	1.153
2032	1.087	1.180
2033	1.107	1.202
2034	1.132	1.229
2035	1.157	1.256
2036	1.177	1.278
2037	1.202	1.306

Note:
1. Gas Turbine prices reflect existing fuel supplier contract specifications and margins.
2. Pricing is consistent with NLH thermal fuel price forecast for Fall 2007.

Source:
- PIRA Energy Group, Oil Price Forecast 10-04-07
- Market Analysis Section, System Planning Dept.

10-Oct-07
Market Analysis Section, System Planning Department

HYDRO Email No. 5

Hearn, Bill G.

From: AndreaMacDonald@nlh.nl.ca
Sent: Friday, October 26, 2007 8:39 AM
To: Hearn, Bill G.
Subject: Updated
Attachments: NLH Inflation & Escalation Forecast - Fall 2007.xls

Bill,
Please see the attached file for the newly updated 2007 escalation and inflation forecast details. I had previously sent you the 2006 version while I was waiting for this updated version.

Andrea

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TABLE 1

NLH INFLATION AND ESCALATION FORECAST

(1997 = 1.000)

	General Inflation		Electric Utility Construction Price Escalation					Operating & Maintenance (O&M)	
	GDP Implicit Price Deflator	Canadian CPI	Thermal Plant Construction	Hydraulic Plant Construction	Transmission Line Construction	Transformer Station Construction	Distribution Line Construction	More Material Less Labour	More Labor Less Material
2000	1.055	1.055	1.058	1.069	1.081	1.076	1.091	1.057	1.059
2001	1.067	1.082	1.072	1.097	1.091	1.102	1.098	1.079	1.092
2002	1.078	1.106	1.102	1.116	1.107	1.123	1.106	1.098	1.121
2003	1.115	1.137	1.115	1.128	1.101	1.089	1.107	1.140	1.168
2004	1.148	1.158	1.180	1.177	1.141	1.101	1.111	1.174	1.204
2005	1.184	1.183	1.217	1.206	1.155	1.121	1.132	1.202	1.223
2006p	1.210	1.207	1.247	1.245	1.205	1.151	1.208	1.228	1.249
2007f	1.254	1.236	1.282	1.281	1.228	1.168	1.235	1.259	1.286
2008	1.285	1.267	1.320	1.319	1.259	1.191	1.266	1.290	1.325
2009	1.311	1.292	1.360	1.359	1.290	1.215	1.304	1.322	1.365
2010	1.337	1.318	1.401	1.400	1.322	1.239	1.343	1.355	1.406
2011	1.364	1.344	1.443	1.442	1.355	1.270	1.383	1.389	1.448
2012	1.391	1.371	1.486	1.485	1.389	1.302	1.424	1.424	1.491
2013	1.419	1.398	1.531	1.530	1.431	1.335	1.467	1.460	1.536
2014	1.447	1.426	1.577	1.576	1.474	1.368	1.511	1.497	1.582
2015	1.476	1.455	1.624	1.623	1.518	1.402	1.556	1.534	1.629
2016	1.506	1.484	1.673	1.672	1.564	1.437	1.603	1.572	1.678
2017	1.536	1.514	1.723	1.722	1.611	1.473	1.651	1.611	1.728
2018	1.567	1.544	1.775	1.774	1.659	1.510	1.701	1.651	1.780
2019	1.598	1.575	1.828	1.827	1.709	1.548	1.752	1.692	1.833
2020	1.630	1.607	1.883	1.882	1.760	1.587	1.805	1.734	1.888
2021	1.663	1.639	1.939	1.938	1.813	1.627	1.859	1.777	1.945
2022	1.696	1.672	1.997	1.996	1.867	1.668	1.915	1.821	2.003
2023	1.730	1.705	2.057	2.056	1.923	1.710	1.972	1.867	2.063
2024	1.765	1.739	2.119	2.118	1.981	1.753	2.031	1.914	2.125
2025	1.800	1.774	2.183	2.182	2.040	1.797	2.092	1.962	2.189
2026	1.836	1.809	2.248	2.247	2.101	1.842	2.155	2.011	2.255
2027	1.873	1.845	2.315	2.314	2.164	1.888	2.220	2.061	2.323

Notes:
1. p is preliminary Statistic's Canada data for Electric Utility Construction Price escalation.
2. General inflation post 2007 is a composite of inflation forecasts provided by Conference Board of Canada.
3. Project specific escalation for the Lower Churchill project is being developed by the LCP Division.

Data Sources: Statistics Canada
Conference Board of Canada

Oct-07
H:\Economic Analysis\Escalation\Fall 2007\[Draft Escalation Forecast for Fall 2007.xls]Indices
Market Analysis Section, System Planning Dept.

HYDRO Email No. 6

Hearn, Bill G.

From:	NSeymour@nlh.nl.ca
Sent:	Tuesday, November 13, 2007 12:16 PM
To:	Hearn, Bill G.
Cc:	AndreaMacDonald@nlh.nl.ca
Subject:	Fw: NLH Gas Turbine Condition Assessment, fuel reports.

Bill,

Please see the annual fuel consumptions for each of the Hwds and Svl gas turbine sites. We only have reports for the past 4 years.

Nelson
----- Forwarded by Nelson Seymour/NLHydro on 11/13/2007 12:43 PM -----

Steve Carter/NLHydro

11/13/2007 08:55 AM

To
Nelson Seymour/NLHydro@NLHydro

cc
Andrea MacDonald/NLHydro@NLHydro, Hughie Ireland/NLHydro@NLHydro, James Wheeler/NLHydro@NLHydro

Subject
NLH Gas Turbine Condition Assessment, fuel reports.(Document link: Nelson Seymour)

Nelson,
I have the fuel reports for the last 4 years only.

2004...HWD...95288 litres, SVL...50241 litres.
2005...HWD...433380 litres, SVL...147566 litres.
2006...HWD...738552 litres, SVL...389686 litres.
2007...HWD...262691 litres, SVL...204485 litres.

Regards
Steve

Nelson Seymour/NLHydro

11/09/2007 01:42 PM

To
Steve Carter/NLHydro@NLHydro, James Wheeler/NLHydro@NLHydro

cc
Andrea MacDonald/NLHydro@NLHydro, Hughie Ireland/NLHydro@NLHydro

Subject
Fw: 21061 - NLH Gas Turbine Condition Assessment

Gentlemen,

Andrea is away until Wednesday. Can you forward this info. to myself next Tuesday please whereby I will relay to Bill Hearn? They are hoping to have a draft report ready for us next week.

Thks,
Nelson
----- Forwarded by Nelson Seymour/NLHydro on 11/09/2007 01:38 PM -----

"Hearn, Bill G." <Bill.Hearn@stantec.com>

11/09/2007 12:26 PM

To
<NSeymour@nlh.nl.ca>, <AndreaMacDonald@nlh.nl.ca>

cc
"King, Brian" <Brian.King@stantec.com>

Subject
21061 - NLH Gas Turbine Condition Assessment

Andrea / Nelson:

Please provide asap, fuel consumption data at the Hardwoods and Stephenville sites on an annual basis for each of the past 5 years. We need this for our ongoing life cycle cost analysis work.

Thanks,
Bill

Bill Hearn, P. Eng
Senior Consultant - Power
Stantec (formerly Neill & Gunter)
#1 South 130 Eileen Stubbs Avenue
Dartmouth NS B3B 2C4
Ph: (902) 434-7331
Fx: (902) 462-1660
Bill.Hearn@stantec.com
stantec.com

APPENDIX 12
FINANCIAL COST ANALYSIS MODEL RUNS

Project Cost/Benefit Analysis Template

Home Page

Current year
2007

Project Title	Hardwoods/Stephenville GT's (Base Cases - Subcase 1)
Project In-Service Year	2008
Number of Years in Study Analysis	16
Discount Rate	**7.0%**
Present Worth Year	2007

(costs are present worthed to January of that year)

Print Home Page

REV 07.01

PROJECT COST / BENEFIT ANALYSIS TEMPLATE

Hardwoods/Stephenville GT's (Base Ca

Hardwoods Refurb - Base Case 1A

HW Refurb - BC1A

Note: Costs are shown as positive values;Benefits as negative values

Current Year	**2007**
Present Worth Year	2007
Number of Years in Study	16
Discount Rate	7.0%
Total In-service Project Cost	$ 8,017,554
In-service Year	2008
Other Project Cost ***after*** In-service (if applicable)	
Other Project Year (if applicable)	
Replacement Cost (if applicable)	$ 11,782,903
Replacement Year (if applicable)	2023
Project cost in Ending (**E**) or Beginning (**B**) Year $$	E
O&M costs - 75% Materials, 25% Labour (**75**) or 50% Materials, 50% Labour (**50**) or User (**U**)	50

A	B	C	D	E	F	G	H	I	J	K	L
Year		**Annual O&M Cost $**	**Annual Fuel Price (if applicable)**	**Annual Fuel Cost $**	**Other Cost $**	**Total Costs $**	**Benefit 1 *(specify)* $**	**Benefit 2 *(specify)* $**	**NET $**	**P.W. January 2007**	**Cumulative Present Worth**
0	2007	-		-	-	-	-	-	-	-	-
1	2008	-		-	-	8,017,554	-	-	8,017,554	7,002,842	7,002,842
2	2009	271,602	0.55	280,083	-	551,685	-	-	551,685	450,339	7,453,181
3	2010	277,849	0.56	282,620	-	560,469	-	-	560,469	427,579	7,880,760
4	2011	284,240	0.58	293,275	-	577,514	-	-	577,514	411,760	8,292,520
5	2012	291,346	0.61	307,482	-	598,827	-	-	598,827	399,024	8,691,544
6	2013	298,629	0.63	320,167	-	618,796	-	-	618,796	385,355	9,076,899
7	2014	306,095	0.67	337,926	-	644,021	-	-	644,021	374,826	9,451,725
8	2015	313,747	0.69	348,074	-	661,821	-	-	661,821	359,987	9,811,712
9	2016	321,591	0.72	365,833	-	687,423	-	-	687,423	349,451	10,161,163
10	2017	329,631	0.75	381,054	-	710,685	-	-	710,685	337,641	10,498,804
11	2018	337,871	0.79	398,813	-	736,685	-	-	736,685	327,097	10,825,901
12	2019	346,318	0.82	414,035	-	760,353	-	-	760,353	315,520	11,141,421
13	2020	354,976	0.85	429,764	-	784,741	-	-	784,741	304,336	11,445,757
14	2021	363,851	0.87	439,912	-	803,763	-	-	803,763	291,321	11,737,077
15	2022	372,947	0.88	447,523	-	820,470	-	-	820,470	277,922	12,014,999
16	2023	382,271	0.90	456,656	-	12,621,830	-	-	12,621,830	3,995,748	16,010,747
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Assumptions & Notes:

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PROJECT COST / BENEFIT ANALYSIS TEMPLATE

Hardwoods/Stephenville GT's (Base Ca
Hardwoods Refurb - Base Case 1B
HW Refurb - BC1B

Note: Costs are shown as positive values;Benefits as negative values

Current Year	**2007**
Present Worth Year	2007
Number of Years in Study	16
Discount Rate	7.0%
Total In-service Project Cost	$ 4,624,059
In-service Year	2008
Other Project Cost ***after*** In-service (if applicable)	
Other Project Year (if applicable)	
Replacement Cost (if applicable)	$ 6,795,693
Replacement Year (if applicable)	2023
Project cost in Ending (**E**) or Beginning (**B**) Year $$	E
O&M costs - 75% Materials, 25% Labour (**75**) or 50% Materials, 50% Labour (**50**) or User (**U**)	50

A	B	C	D	E	F	G	H	I	J	K	L
Year		Annual O&M Cost $	Annual Fuel Price (if applicable)	Annual Fuel Cost $	Other Cost $	Total Costs $	Benefit 1 *(specify)* $	Benefit 2 *(specify)* $	NET $	P.W. January 2007	Cumulative Present Worth
0	2007	-		-	-	-	-	-	-	-	-
1	2008	-		-	-	4,624,059	-	-	4,624,059	4,038,832	4,038,832
2	2009	271,602	0.55	280,083	-	551,685	-	-	551,685	450,339	4,489,171
3	2010	277,849	0.56	282,620	-	560,469	-	-	560,469	427,579	4,916,750
4	2011	284,240	0.58	293,275	-	577,514	-	-	577,514	411,760	5,328,510
5	2012	291,346	0.61	307,482	-	598,827	-	-	598,827	399,024	5,727,534
6	2013	298,629	0.63	320,167	-	618,796	-	-	618,796	385,355	6,112,889
7	2014	306,095	0.67	337,926	-	644,021	-	-	644,021	374,826	6,487,715
8	2015	313,747	0.69	348,074	-	661,821	-	-	661,821	359,987	6,847,702
9	2016	321,591	0.72	365,833	-	687,423	-	-	687,423	349,451	7,197,153
10	2017	329,631	0.75	381,054	-	710,685	-	-	710,685	337,641	7,534,794
11	2018	337,871	0.79	398,813	-	736,685	-	-	736,685	327,097	7,861,891
12	2019	346,318	0.82	414,035	-	760,353	-	-	760,353	315,520	8,177,411
13	2020	354,976	0.85	429,764	-	784,741	-	-	784,741	304,336	8,481,747
14	2021	363,851	0.87	439,912	-	803,763	-	-	803,763	291,321	8,773,067
15	2022	372,947	0.88	447,523	-	820,470	-	-	820,470	277,922	9,050,989
16	2023	382,271	0.90	456,656	-	7,634,620	-	-	7,634,620	2,416,925	11,467,914
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Assumptions & Notes:

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PROJECT COST / BENEFIT ANALYSIS TEMPLATE

Hardwoods/Stephenville GT's (Base Ca

Stephenville Refurb - Base Case 2A

SV ReFurb - BC2A

Note: Costs are shown as positive values;Benefits as negative values

Current Year	**2007**
Present Worth Year	2007
Number of Years in Study	16
Discount Rate	7.0%
Total In-service Project Cost	$ 8,050,389
In-service Year	2008
Other Project Cost ***after*** In-service (if applicable)	
Other Project Year (if applicable)	
Replacement Cost (if applicable)	$ 11,831,159
Replacement Year (if applicable)	2023
Project cost in Ending (**E**) or Beginning (**B**) Year $$	E
O&M costs - 75% Materials, 25% Labour (**75**) or 50% Materials, 50% Labour (**50**) or User (**U**)	50

A	B	C	D	E	F	G	H	I	J	K	L
Year		**Annual O&M Cost $**	**Annual Fuel Price** (if applicable)	**Annual Fuel Cost $**	**Other Cost $**	**Total Costs $**	**Benefit 1 *(specify)* $**	**Benefit 2 *(specify)* $**	**NET $**	**P.W. January 2007**	**Cumulative Present Worth**
0	2007	-		-	-	-	-	-	-	-	-
1	2008	-		-	-	8,050,389	-	-	8,050,389	7,031,522	7,031,522
2	2009	157,035	0.61	165,489	-	322,524	-	-	322,524	263,276	7,294,797
3	2010	160,647	0.62	167,109	-	327,755	-	-	327,755	250,043	7,544,840
4	2011	164,341	0.64	172,778	-	337,120	-	-	337,120	240,362	7,785,202
5	2012	168,450	0.67	180,337	-	348,787	-	-	348,787	232,412	8,017,614
6	2013	172,661	0.69	187,356	-	360,018	-	-	360,018	224,201	8,241,814
7	2014	176,978	0.73	197,075	-	374,053	-	-	374,053	217,702	8,459,517
8	2015	181,402	0.75	203,014	-	384,417	-	-	384,417	209,097	8,668,614
9	2016	185,937	0.79	212,733	-	398,670	-	-	398,670	202,664	8,871,278
10	2017	190,586	0.82	221,372	-	411,958	-	-	411,958	195,718	9,066,996
11	2018	195,350	0.86	231,091	-	426,441	-	-	426,441	189,345	9,256,341
12	2019	200,234	0.89	239,730	-	439,964	-	-	439,964	182,569	9,438,910
13	2020	205,240	0.92	248,099	-	453,339	-	-	453,339	175,813	9,614,723
14	2021	210,371	0.94	254,038	-	464,409	-	-	464,409	168,323	9,783,046
15	2022	215,630	0.96	258,357	-	473,988	-	-	473,988	160,556	9,943,602
16	2023	221,021	0.98	264,567	-	12,316,747	-	-	12,316,747	3,899,167	13,842,768
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Assumptions & Notes:

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PROJECT COST / BENEFIT ANALYSIS TEMPLATE

Hardwoods/Stephenville GT's (Base Ca

Stephenville Refurb - Base Case 2B

SV ReFurb - BC2B

Note: Costs are shown as positive values;Benefits as negative values

Current Year	**2007**
Present Worth Year	2007
Number of Years in Study	16
Discount Rate	7.0%
Total In-service Project Cost	$ 4,656,894
In-service Year	2008
Other Project Cost ***after*** In-service (if applicable)	
Other Project Year (if applicable)	
Replacement Cost (if applicable)	$ 6,843,949
Replacement Year (if applicable)	2023
Project cost in Ending (**E**) or Beginning (**B**) Year $$	E
O&M costs - 75% Materials, 25% Labour (**75**) or 50% Materials, 50% Labour (**50**) or User (**U**)	50

A	B	C	D	E	F	G	H	I	J	K	L
Year		**Annual O&M Cost $**	**Annual Fuel Price (if applicable)**	**Annual Fuel Cost $**	**Other Cost $**	**Total Costs $**	**Benefit 1 *(specify)* $**	**Benefit 2 *(specify)* $**	**NET $**	**P.W. January 2007**	**Cumulative Present Worth**
0	2007	-		-	-	-	-	-	-	-	-
1	2008	-		-	-	4,656,894	-	-	4,656,894	4,067,512	4,067,512
2	2009	157,035	0.61	165,489	51,765	374,289	-	-	374,289	305,531	4,373,043
3	2010	160,647	0.62	167,109	-	327,755	-	-	327,755	250,043	4,623,086
4	2011	164,341	0.64	172,778	66,488	403,607	-	-	403,607	287,766	4,910,853
5	2012	168,450	0.67	180,337	-	348,787	-	-	348,787	232,412	5,143,264
6	2013	172,661	0.69	187,356	93,138	453,156	-	-	453,156	282,203	5,425,467
7	2014	176,978	0.73	197,075	-	374,053	-	-	374,053	217,702	5,643,169
8	2015	181,402	0.75	203,014	98,044	482,461	-	-	482,461	262,427	5,905,596
9	2016	185,937	0.79	212,733	-	398,670	-	-	398,670	202,664	6,108,260
10	2017	190,586	0.82	221,372	-	411,958	-	-	411,958	195,718	6,303,978
11	2018	195,350	0.86	231,091	-	426,441	-	-	426,441	189,345	6,493,323
12	2019	200,234	0.89	239,730	-	439,964	-	-	439,964	182,569	6,675,892
13	2020	205,240	0.92	248,099	-	453,339	-	-	453,339	175,813	6,851,705
14	2021	210,371	0.94	254,038	-	464,409	-	-	464,409	168,323	7,020,028
15	2022	215,630	0.96	258,357	-	473,988	-	-	473,988	160,556	7,180,584
16	2023	221,021	0.98	264,567	150,491	7,480,028	-	-	7,480,028	2,367,985	9,548,569
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Assumptions & Notes:

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PROJECT COST / BENEFIT ANALYSIS TEMPLATE

Hardwoods/Stephenville GT's (Base Ca

DVAR - Hardwoods

DVAR

Note: Costs are shown as positive values;Benefits as negative values

Current Year	**2007**
Present Worth Year	2007
Number of Years in Study	16
Discount Rate	7.0%
Total In-service Project Cost	$ 10,000,000
In-service Year	2008
Other Project Cost ***after*** In-service (if applicable)	
Other Project Year (if applicable)	
Replacement Cost (if applicable)	
Replacement Year (if applicable)	2023
Project cost in Ending (**E**) or Beginning (**B**) Year $$	E
O&M costs - 75% Materials, 25% Labour (**75**) or 50% Materials, 50% Labour (**50**) or User (**U**)	U

A	B	C	D	E	F	G	H	I	J	K	L
Year		**Annual O&M Cost $**	**Annual Fuel Price (if applicable)**	**Annual Fuel Cost $**	**Other Cost $**	**Total Costs $**	**Benefit 1 *(specify)* $**	**Benefit 2 *(specify)* $**	**NET $**	**P.W. January 2007**	**Cumulative Present Worth**
0	2007	-		-	-	-	-	-	-	-	-
1	2008	-		-	-	10,000,000	-	-	10,000,000	8,734,387	8,734,387
2	2009	27,479		-	-	27,479	-	-	27,479	22,431	8,756,819
3	2010	28,304		-	-	28,304	-	-	28,304	21,593	8,778,412
4	2011	29,153		-	-	29,153	-	-	29,153	20,786	8,799,197
5	2012	30,028		-	-	30,028	-	-	30,028	20,009	8,819,206
6	2013	30,928		-	-	30,928	-	-	30,928	19,261	8,838,466
7	2014	31,856		-	-	31,856	-	-	31,856	18,541	8,857,007
8	2015	32,812		-	-	32,812	-	-	32,812	17,847	8,874,854
9	2016	33,796		-	-	33,796	-	-	33,796	17,180	8,892,035
10	2017	34,810		-	-	34,810	-	-	34,810	16,538	8,908,573
11	2018	35,854		-	-	35,854	-	-	35,854	15,920	8,924,493
12	2019	36,930		-	-	36,930	-	-	36,930	15,325	8,939,817
13	2020	38,038		-	-	38,038	-	-	38,038	14,752	8,954,569
14	2021	39,179		-	-	39,179	-	-	39,179	14,200	8,968,769
15	2022	40,354		-	-	40,354	-	-	40,354	13,669	8,982,439
16	2023	41,565		-	-	41,565	-	-	41,565	13,158	8,995,597
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Assumptions & Notes:

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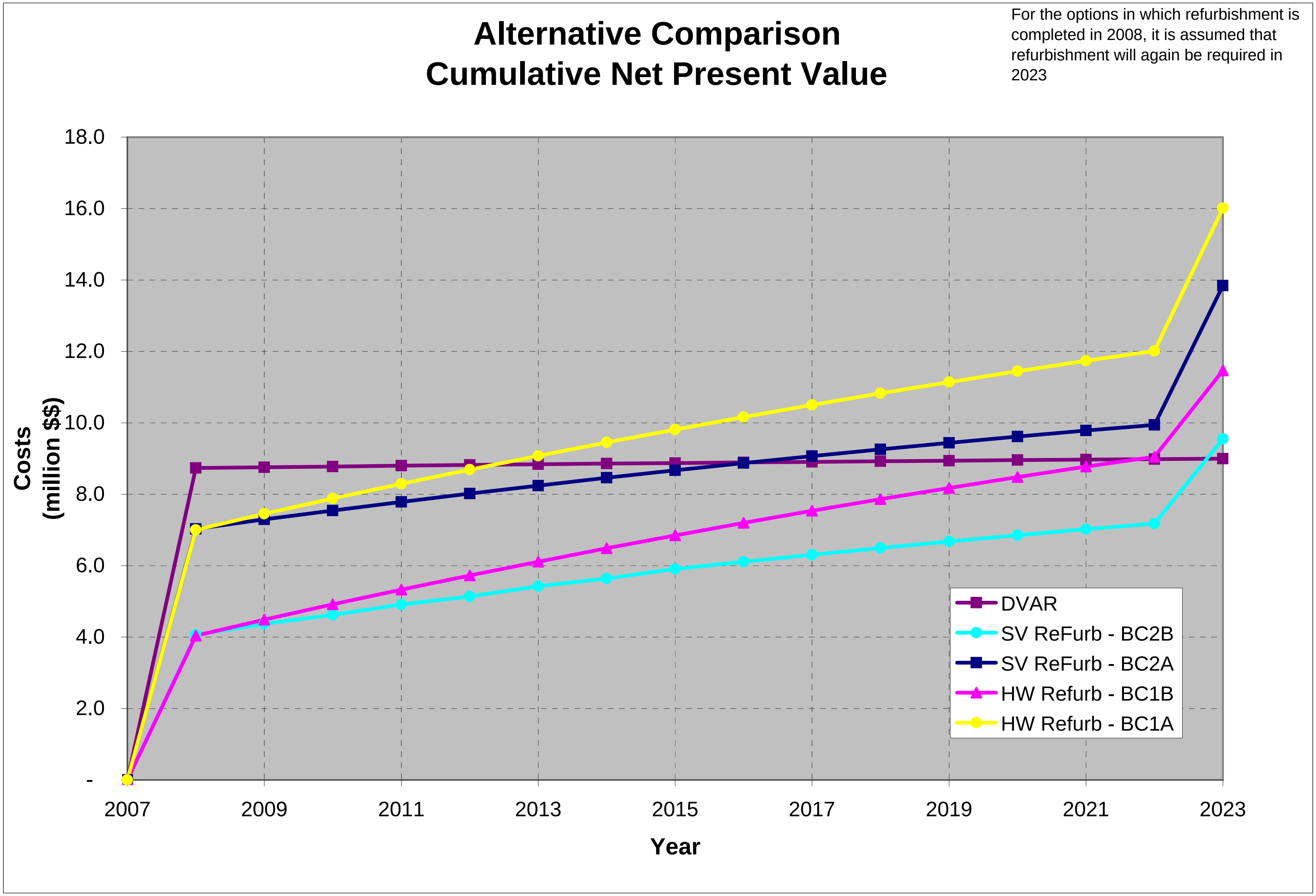
Alternative Comparison
Cumulative Net Present Value
For the options in which refurbishment is completed in 2008, it is assumed that refurbishment will again be required in 2023
Costs
(million $$)
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14.0
12.0
10.0
8.0
6.0
4.0
2.0
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2007
2009
2011
2013
2015
2017
2019
2021
2023
Year
DVAR
SV ReFurb - BC2B
SV ReFurb - BC2A
HW Refurb - BC1B
HW Refurb - BC1A

Hardwoods/Stephenville GT's (Base Cases - Subcase 1)

Alternative Comparison

Cumulative Net Present Value

To The Year

2023

Alternatives	Cumulative Net Present Value (CPW)	CPW Difference between Alternative and the Least Cost Alternative
Hardwoods Refurb - Base Case 1A	16,010,747	7,015,150
Hardwoods Refurb - Base Case 1B	11,467,914	2,472,317
Stephenville Refurb - Base Case 2A	13,842,768	4,847,171
Stephenville Refurb - Base Case 2B	9,548,569	552,972
DVAR - Hardwoods	8,995,597	0

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Project Cost/Benefit Analysis Template

Home Page

Current year
2007

Project Title	Hardwoods/Stephenville GT's (Base Cases - Subcase 2)
Project In-Service Year	2008
Number of Years in Study Analysis	16
Discount Rate	7.0%
Present Worth Year	2007

(costs are present worthed to January of that year)

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REV 07.01

PROJECT COST / BENEFIT ANALYSIS TEMPLATE

Hardwoods/Stephenville GT's (Base Ca

Hardwoods Refurb - Base Case 1A

HW Refurb - BC1A

Note: Costs are shown as positive values;Benefits as negative values

Current Year	**2007**
Present Worth Year	2007
Number of Years in Study	16
Discount Rate	7.0%
Total In-service Project Cost	$ 8,017,554
In-service Year	2008
Other Project Cost ***after*** In-service (if applicable)	
Other Project Year (if applicable)	
Replacement Cost (if applicable)	$ 55,639,618
Replacement Year (if applicable)	2023
Project cost in Ending (**E**) or Beginning (**B**) Year $$	E
O&M costs - 75% Materials, 25% Labour (**75**) or 50% Materials, 50% Labour (**50**) or User (**U**)	50

A	B	C	D	E	F	G	H	I	J	K	L
Year		Annual O&M Cost $	Annual Fuel Price (if applicable)	Annual Fuel Cost $	Other Cost $	Total Costs $	Benefit 1 *(specify)* $	Benefit 2 *(specify)* $	NET $	P.W. January 2007	Cumulative Present Worth
0	2007	-		-	-	-	-	-	-	-	-
1	2008	-		-	-	8,017,554	-	-	8,017,554	7,002,842	7,002,842
2	2009	271,602	0.55	280,083	-	551,685	-	-	551,685	450,339	7,453,181
3	2010	277,849	0.56	282,620	-	560,469	-	-	560,469	427,579	7,880,760
4	2011	284,240	0.58	293,275	-	577,514	-	-	577,514	411,760	8,292,520
5	2012	291,346	0.61	307,482	-	598,827	-	-	598,827	399,024	8,691,544
6	2013	298,629	0.63	320,167	-	618,796	-	-	618,796	385,355	9,076,899
7	2014	306,095	0.67	337,926	-	644,021	-	-	644,021	374,826	9,451,725
8	2015	313,747	0.69	348,074	-	661,821	-	-	661,821	359,987	9,811,712
9	2016	321,591	0.72	365,833	-	687,423	-	-	687,423	349,451	10,161,163
10	2017	329,631	0.75	381,054	-	710,685	-	-	710,685	337,641	10,498,804
11	2018	337,871	0.79	398,813	-	736,685	-	-	736,685	327,097	10,825,901
12	2019	346,318	0.82	414,035	-	760,353	-	-	760,353	315,520	11,141,421
13	2020	354,976	0.85	429,764	-	784,741	-	-	784,741	304,336	11,445,757
14	2021	363,851	0.87	439,912	-	803,763	-	-	803,763	291,321	11,737,077
15	2022	372,947	0.88	447,523	-	820,470	-	-	820,470	277,922	12,014,999
16	2023	382,271	0.90	456,656	-	56,478,545	-	-	56,478,545	17,879,661	29,894,660
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PROJECT COST / BENEFIT ANALYSIS TEMPLATE

Hardwoods/Stephenville GT's (Base Ca
Hardwoods Refurb - Base Case 1B
HW Refurb - BC1B

Note: Costs are shown as positive values;Benefits as negative values

Current Year	**2007**
Present Worth Year	2007
Number of Years in Study	16
Discount Rate	7.0%
Total In-service Project Cost	$ 4,624,059
In-service Year	2008
Other Project Cost ***after*** In-service (if applicable)	
Other Project Year (if applicable)	
Replacement Cost (if applicable)	$ 55,639,618
Replacement Year (if applicable)	2023
Project cost in Ending (**E**) or Beginning (**B**) Year $$	E
O&M costs - 75% Materials, 25% Labour (**75**) or 50% Materials, 50% Labour (**50**) or User (**U**)	50

A	B	C	D	E	F	G	H	I	J	K	L
Year		Annual O&M Cost $	Annual Fuel Price (if applicable)	Annual Fuel Cost $	Other Cost $	Total Costs $	Benefit 1 *(specify)* $	Benefit 2 *(specify)* $	NET $	P.W. January 2007	Cumulative Present Worth
0	2007	-		-	-	-	-	-	-	-	-
1	2008	-		-	-	4,624,059	-	-	4,624,059	4,038,832	4,038,832
2	2009	271,602	0.55	280,083	-	551,685	-	-	551,685	450,339	4,489,171
3	2010	277,849	0.56	282,620	-	560,469	-	-	560,469	427,579	4,916,750
4	2011	284,240	0.58	293,275	-	577,514	-	-	577,514	411,760	5,328,510
5	2012	291,346	0.61	307,482	-	598,827	-	-	598,827	399,024	5,727,534
6	2013	298,629	0.63	320,167	-	618,796	-	-	618,796	385,355	6,112,889
7	2014	306,095	0.67	337,926	-	644,021	-	-	644,021	374,826	6,487,715
8	2015	313,747	0.69	348,074	-	661,821	-	-	661,821	359,987	6,847,702
9	2016	321,591	0.72	365,833	-	687,423	-	-	687,423	349,451	7,197,153
10	2017	329,631	0.75	381,054	-	710,685	-	-	710,685	337,641	7,534,794
11	2018	337,871	0.79	398,813	-	736,685	-	-	736,685	327,097	7,861,891
12	2019	346,318	0.82	414,035	-	760,353	-	-	760,353	315,520	8,177,411
13	2020	354,976	0.85	429,764	-	784,741	-	-	784,741	304,336	8,481,747
14	2021	363,851	0.87	439,912	-	803,763	-	-	803,763	291,321	8,773,067
15	2022	372,947	0.88	447,523	-	820,470	-	-	820,470	277,922	9,050,989
16	2023	382,271	0.90	456,656	-	56,478,545	-	-	56,478,545	17,879,661	26,930,650
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PROJECT COST / BENEFIT ANALYSIS TEMPLATE
Hardwoods/Stephenville GT's (Base Ca
Stephenville Refurb - Base Case 2A
SV ReFurb - BC2A

Note: Costs are shown as positive values;Benefits as negative values

Current Year	**2007**
Present Worth Year	2007
Number of Years in Study	16
Discount Rate	7.0%
Total In-service Project Cost	$ 8,050,389
In-service Year	2008
Other Project Cost ***after*** In-service (if applicable)	
Other Project Year (if applicable)	
Replacement Cost (if applicable)	$ 55,639,618
Replacement Year (if applicable)	2023
Project cost in Ending (**E**) or Beginning (**B**) Year $$	E
O&M costs - 75% Materials, 25% Labour (**75**) or 50% Materials, 50% Labour (**50**) or User (**U**)	50

A	B	C	D	E	F	G	H	I	J	K	L
Year		Annual O&M Cost $	Annual Fuel Price (if applicable)	Annual Fuel Cost $	Other Cost $	Total Costs $	Benefit 1 *(specify)* $	Benefit 2 *(specify)* $	NET $	P.W. January 2007	Cumulative Present Worth
0	2007	-		-	-	-	-	-	-	-	-
1	2008	-		-	-	8,050,389	-	-	8,050,389	7,031,522	7,031,522
2	2009	157,035	0.61	165,489	-	322,524	-	-	322,524	263,276	7,294,797
3	2010	160,647	0.62	167,109	-	327,755	-	-	327,755	250,043	7,544,840
4	2011	164,341	0.64	172,778	-	337,120	-	-	337,120	240,362	7,785,202
5	2012	168,450	0.67	180,337	-	348,787	-	-	348,787	232,412	8,017,614
6	2013	172,661	0.69	187,356	-	360,018	-	-	360,018	224,201	8,241,814
7	2014	176,978	0.73	197,075	-	374,053	-	-	374,053	217,702	8,459,517
8	2015	181,402	0.75	203,014	-	384,417	-	-	384,417	209,097	8,668,614
9	2016	185,937	0.79	212,733	-	398,670	-	-	398,670	202,664	8,871,278
10	2017	190,586	0.82	221,372	-	411,958	-	-	411,958	195,718	9,066,996
11	2018	195,350	0.86	231,091	-	426,441	-	-	426,441	189,345	9,256,341
12	2019	200,234	0.89	239,730	-	439,964	-	-	439,964	182,569	9,438,910
13	2020	205,240	0.92	248,099	-	453,339	-	-	453,339	175,813	9,614,723
14	2021	210,371	0.94	254,038	-	464,409	-	-	464,409	168,323	9,783,046
15	2022	215,630	0.96	258,357	-	473,988	-	-	473,988	160,556	9,943,602
16	2023	221,021	0.98	264,567	-	56,125,206	-	-	56,125,206	17,767,803	27,711,405
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Assumptions & Notes:

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PROJECT COST / BENEFIT ANALYSIS TEMPLATE

Hardwoods/Stephenville GT's (Base Ca
Stephenville Refurb - Base Case 2B
SV ReFurb - BC2B

Note: Costs are shown as positive values;Benefits as negative values

Current Year	**2007**
Present Worth Year	2007
Number of Years in Study	16
Discount Rate	7.0%
Total In-service Project Cost	$ 4,656,894
In-service Year	2008
Other Project Cost ***after*** In-service (if applicable)	
Other Project Year (if applicable)	
Replacement Cost (if applicable)	$ 55,639,618
Replacement Year (if applicable)	2023
Project cost in Ending (**E**) or Beginning (**B**) Year $$	E
O&M costs - 75% Materials, 25% Labour (**75**) or 50% Materials, 50% Labour (**50**) or User (**U**)	50

A	B	C	D	E	F	G	H	I	J	K	L
Year		**Annual O&M Cost $**	**Annual Fuel Price** (if applicable)	**Annual Fuel Cost $**	**Other Cost $**	**Total Costs $**	**Benefit 1 *(specify)* $**	**Benefit 2 *(specify)* $**	**NET $**	**P.W. January 2007**	**Cumulative Present Worth**
0	2007	-		-	-	-	-	-	-	-	-
1	2008	-		-	-	4,656,894	-	-	4,656,894	4,067,512	4,067,512
2	2009	157,035	0.61	165,489	51,765	374,289	-	-	374,289	305,531	4,373,043
3	2010	160,647	0.62	167,109	-	327,755	-	-	327,755	250,043	4,623,086
4	2011	164,341	0.64	172,778	66,488	403,607	-	-	403,607	287,766	4,910,853
5	2012	168,450	0.67	180,337	-	348,787	-	-	348,787	232,412	5,143,264
6	2013	172,661	0.69	187,356	93,138	453,156	-	-	453,156	282,203	5,425,467
7	2014	176,978	0.73	197,075	-	374,053	-	-	374,053	217,702	5,643,169
8	2015	181,402	0.75	203,014	98,044	482,461	-	-	482,461	262,427	5,905,596
9	2016	185,937	0.79	212,733	-	398,670	-	-	398,670	202,664	6,108,260
10	2017	190,586	0.82	221,372	-	411,958	-	-	411,958	195,718	6,303,978
11	2018	195,350	0.86	231,091	-	426,441	-	-	426,441	189,345	6,493,323
12	2019	200,234	0.89	239,730	-	439,964	-	-	439,964	182,569	6,675,892
13	2020	205,240	0.92	248,099	-	453,339	-	-	453,339	175,813	6,851,705
14	2021	210,371	0.94	254,038	-	464,409	-	-	464,409	168,323	7,020,028
15	2022	215,630	0.96	258,357	-	473,988	-	-	473,988	160,556	7,180,584
16	2023	221,021	0.98	264,567	150,491	56,275,697	-	-	56,275,697	17,815,444	24,996,028
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Assumptions & Notes:

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PROJECT COST / BENEFIT ANALYSIS TEMPLATE

Hardwoods/Stephenville GT's (Base Ca

DVAR - One Site

DVAR

Note: Costs are shown as positive values;Benefits as negative values

Current Year	**2007**
Present Worth Year	2007
Number of Years in Study	16
Discount Rate	7.0%
Total In-service Project Cost	$ 10,000,000
In-service Year	2008
Other Project Cost ***after*** In-service (if applicable)	
Other Project Year (if applicable)	
Replacement Cost (if applicable)	
Replacement Year (if applicable)	2023
Project cost in Ending (**E**) or Beginning (**B**) Year $$	E
O&M costs - 75% Materials, 25% Labour (**75**) or 50% Materials, 50% Labour (**50**) or User (**U**)	U

A	B	C	D	E	F	G	H	I	J	K	L
Year		Annual O&M Cost $	Annual Fuel Price (if applicable)	Annual Fuel Cost $	Other Cost $	Total Costs $	Benefit 1 *(specify)* $	Benefit 2 *(specify)* $	NET $	P.W. January 2007	Cumulative Present Worth
0	2007	-		-	-	-	-	-	-	-	-
1	2008	-		-	-	10,000,000	-	-	10,000,000	8,734,387	8,734,387
2	2009	27,479		-	-	27,479	-	-	27,479	22,431	8,756,819
3	2010	28,304		-	-	28,304	-	-	28,304	21,593	8,778,412
4	2011	29,153		-	-	29,153	-	-	29,153	20,786	8,799,197
5	2012	30,028		-	-	30,028	-	-	30,028	20,009	8,819,206
6	2013	30,928		-	-	30,928	-	-	30,928	19,261	8,838,466
7	2014	31,856		-	-	31,856	-	-	31,856	18,541	8,857,007
8	2015	32,812		-	-	32,812	-	-	32,812	17,847	8,874,854
9	2016	33,796		-	-	33,796	-	-	33,796	17,180	8,892,035
10	2017	34,810		-	-	34,810	-	-	34,810	16,538	8,908,573
11	2018	35,854		-	-	35,854	-	-	35,854	15,920	8,924,493
12	2019	36,930		-	-	36,930	-	-	36,930	15,325	8,939,817
13	2020	38,038		-	-	38,038	-	-	38,038	14,752	8,954,569
14	2021	39,179		-	-	39,179	-	-	39,179	14,200	8,968,769
15	2022	40,354		-	-	40,354	-	-	40,354	13,669	8,982,439
16	2023	41,565		-	-	41,565	-	-	41,565	13,158	8,995,597
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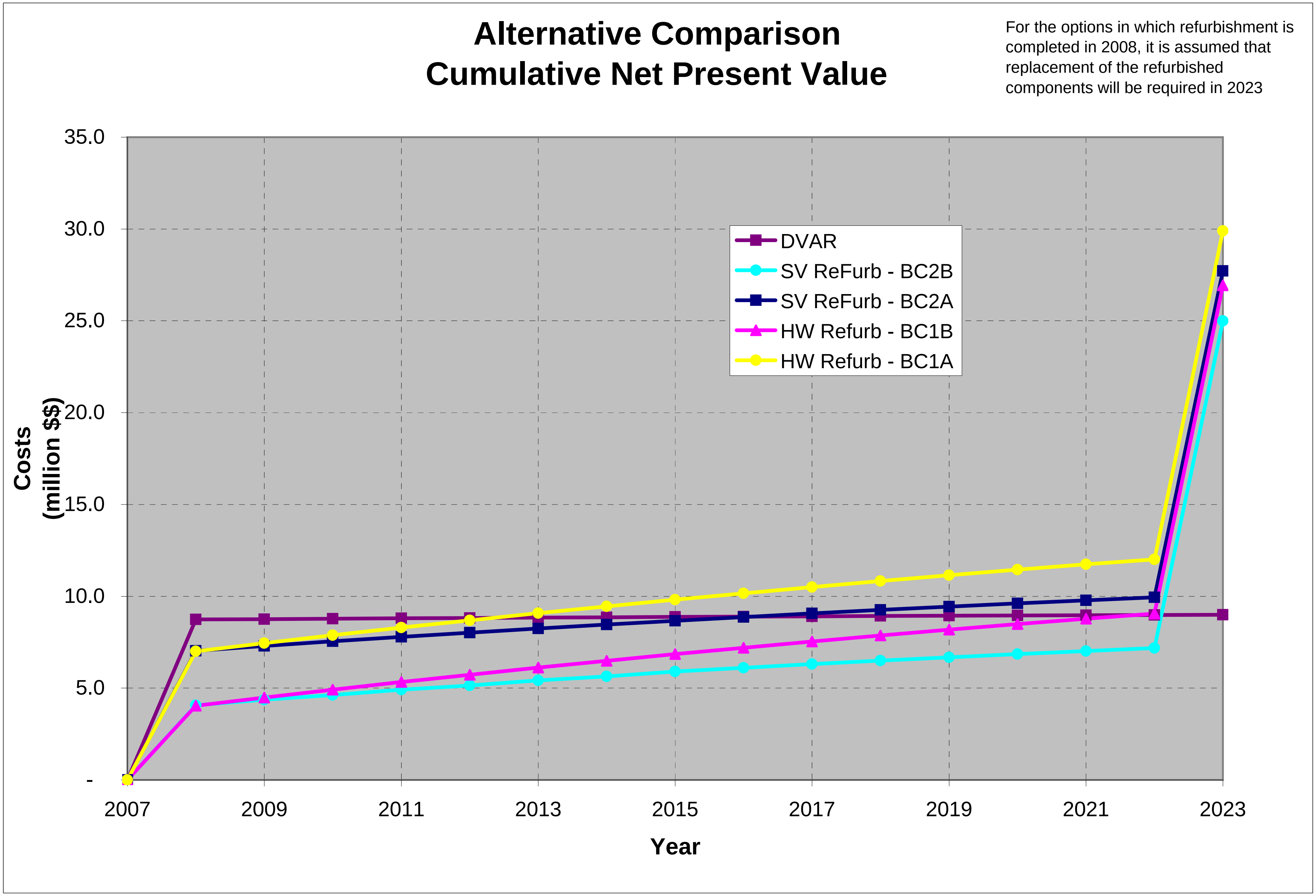
Alternative Comparison
Cumulative Net Present Value
For the options in which refurbishment is completed in 2008, it is assumed that replacement of the refurbished components will be required in 2023
DVAR
SV ReFurb - BC2B
SV ReFurb - BC2A
HW Refurb - BC1B
HW Refurb - BC1A
Costs (million $$)
35.0
30.0
25.0
20.0
15.0
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2007
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2017
2019
2021
2023
Year

Hardwoods/Stephenville GT's (Base Cases - Subcase 2)

Alternative Comparison

Cumulative Net Present Value

To The Year

2023

Alternatives	Cumulative Net Present Value (CPW)	CPW Difference between Alternative and the Least Cost Alternative
Hardwoods Refurb - Base Case 1A	29,894,660	20,899,063
Hardwoods Refurb - Base Case 1B	26,930,650	17,935,053
Stephenville Refurb - Base Case 2A	27,711,405	18,715,807
Stephenville Refurb - Base Case 2B	24,996,028	16,000,431
DVAR - One Site	8,995,597	0

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Project Cost/Benefit Analysis Template

Home Page

Current year
2007

Project Title	Hardwoods/Stephenville GT's (Options Subcase 1)
Project In-Service Year	2008
Number of Years in Study Analysis	16
Discount Rate	7.0%
Present Worth Year	2007

(costs are present worthed to January of that year)

Print Home Page

REV 07.01

PROJECT COST / BENEFIT ANALYSIS TEMPLATE

Hardwoods/Stephenville GT's (Options
Hardwoods Refurb - Base Case 1A
HW Refurb - BC1A

Note: Costs are shown as positive values;Benefits as negative values

Current Year	**2007**
Present Worth Year	2007
Number of Years in Study	16
Discount Rate	7.0%
Total In-service Project Cost	$ 8,017,554
In-service Year	2008
Other Project Cost ***after*** In-service (if applicable)	
Other Project Year (if applicable)	
Replacement Cost (if applicable)	$ 11,782,903
Replacement Year (if applicable)	2023
Project cost in Ending (**E**) or Beginning (**B**) Year $$	E
O&M costs - 75% Materials, 25% Labour (**75**) or 50% Materials, 50% Labour (**50**) or User (**U**)	50

A	B	C	D	E	F	G	H	I	J	K	L
Year		**Annual O&M Cost $**	**Annual Fuel Price** (if applicable)	**Annual Fuel Cost $**	**Other Cost $**	**Total Costs $**	**Benefit 1 *(specify)* $**	**Benefit 2 *(specify)* $**	**NET $**	**P.W. January 2007**	**Cumulative Present Worth**
0	2007	-		-	-	-	-	-	-	-	-
1	2008	-		-	-	8,017,554	-	-	8,017,554	7,002,842	7,002,842
2	2009	271,602	0.55	280,083	-	551,685	-	-	551,685	450,339	7,453,181
3	2010	277,849	0.56	282,620	-	560,469	-	-	560,469	427,579	7,880,760
4	2011	284,240	0.58	293,275	-	577,514	-	-	577,514	411,760	8,292,520
5	2012	291,346	0.61	307,482	-	598,827	-	-	598,827	399,024	8,691,544
6	2013	298,629	0.63	320,167	-	618,796	-	-	618,796	385,355	9,076,899
7	2014	306,095	0.67	337,926	-	644,021	-	-	644,021	374,826	9,451,725
8	2015	313,747	0.69	348,074	-	661,821	-	-	661,821	359,987	9,811,712
9	2016	321,591	0.72	365,833	-	687,423	-	-	687,423	349,451	10,161,163
10	2017	329,631	0.75	381,054	-	710,685	-	-	710,685	337,641	10,498,804
11	2018	337,871	0.79	398,813	-	736,685	-	-	736,685	327,097	10,825,901
12	2019	346,318	0.82	414,035	-	760,353	-	-	760,353	315,520	11,141,421
13	2020	354,976	0.85	429,764	-	784,741	-	-	784,741	304,336	11,445,757
14	2021	363,851	0.87	439,912	-	803,763	-	-	803,763	291,321	11,737,077
15	2022	372,947	0.88	447,523	-	820,470	-	-	820,470	277,922	12,014,999
16	2023	382,271	0.90	456,656	-	12,621,830	-	-	12,621,830	3,995,748	16,010,747
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Assumptions & Notes:

-Refurbishment of engines, alternator and BOP
-Includes allowance for rental mobile equipment during refurbishment period
-Fuel costs based on HYDRO price forecast and historical consumption
-O&M costs based on 90% of historical average
-Assumes refurbishment required in 2023 (reflected as replacement cost)

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PROJECT COST / BENEFIT ANALYSIS TEMPLATE

Hardwoods/Stephenville GT's (Options
Stephenville Refurb - Base Case 2A
SV ReFurb - BC2A

Note: Costs are shown as positive values;Benefits as negative values

Current Year	**2007**
Present Worth Year	2007
Number of Years in Study	16
Discount Rate	7.0%
Total In-service Project Cost	$ 8,050,389
In-service Year	2008
Other Project Cost ***after*** In-service (if applicable)	
Other Project Year (if applicable)	
Replacement Cost (if applicable)	$ 11,831,159
Replacement Year (if applicable)	2023
Project cost in Ending (**E**) or Beginning (**B**) Year $$	E
O&M costs - 75% Materials, 25% Labour (**75**) or 50% Materials, 50% Labour (**50**) or User (**U**)	50

A	B	C	D	E	F	G	H	I	J	K	L
Year		Annual O&M Cost $	Annual Fuel Price (if applicable)	Annual Fuel Cost $	Other Cost $	Total Costs $	Benefit 1 *(specify)* $	Benefit 2 *(specify)* $	NET $	P.W. January 2007	Cumulative Present Worth
0	2007	-		-	-	-	-	-	-	-	-
1	2008	-		-	-	8,050,389	-	-	8,050,389	7,031,522	7,031,522
2	2009	157,035	0.61	165,489	-	322,524	-	-	322,524	263,276	7,294,797
3	2010	160,647	0.62	167,109	-	327,755	-	-	327,755	250,043	7,544,840
4	2011	164,341	0.64	172,778	-	337,120	-	-	337,120	240,362	7,785,202
5	2012	168,450	0.67	180,337	-	348,787	-	-	348,787	232,412	8,017,614
6	2013	172,661	0.69	187,356	-	360,018	-	-	360,018	224,201	8,241,814
7	2014	176,978	0.73	197,075	-	374,053	-	-	374,053	217,702	8,459,517
8	2015	181,402	0.75	203,014	-	384,417	-	-	384,417	209,097	8,668,614
9	2016	185,937	0.79	212,733	-	398,670	-	-	398,670	202,664	8,871,278
10	2017	190,586	0.82	221,372	-	411,958	-	-	411,958	195,718	9,066,996
11	2018	195,350	0.86	231,091	-	426,441	-	-	426,441	189,345	9,256,341
12	2019	200,234	0.89	239,730	-	439,964	-	-	439,964	182,569	9,438,910
13	2020	205,240	0.92	248,099	-	453,339	-	-	453,339	175,813	9,614,723
14	2021	210,371	0.94	254,038	-	464,409	-	-	464,409	168,323	9,783,046
15	2022	215,630	0.96	258,357	-	473,988	-	-	473,988	160,556	9,943,602
16	2023	221,021	0.98	264,567	-	12,316,747	-	-	12,316,747	3,899,167	13,842,768
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Assumptions & Notes:

-Refurbishment of engines, alternator and BOP
-Includes allowance for rental mobile equipment during refurbishment period
-Fuel costs based on HYDRO price forecast and historical consumption
-O&M costs based on 90% of historical average
-Assumes refurbishment required in 2023 (reflected as replacement cost)

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PROJECT COST / BENEFIT ANALYSIS TEMPLATE

Hardwoods/Stephenville GT's (Options

New GT/Refurb Alt - Option 1

New GT - Opt1

Note: Costs are shown as positive values;Benefits as negative values

Current Year	**2007**
Present Worth Year	2007
Number of Years in Study	16
Discount Rate	7.0%
Total In-service Project Cost	$ 30,500,170
In-service Year	2008
Other Project Cost ***after*** In-service (if applicable)	
Other Project Year (if applicable)	
Replacement Cost (if applicable)	$ 5,891,452
Replacement Year (if applicable)	2023
Project cost in Ending (**E**) or Beginning (**B**) Year $$	E
O&M costs - 75% Materials, 25% Labour (**75**) or 50% Materials, 50% Labour (**50**) or User (**U**)	50

A	B	C	D	E	F	G	H	I	J	K	L
Year		Annual O&M Cost $	Annual Fuel Price (if applicable)	Annual Fuel Cost $	Other Cost $	Total Costs $	Benefit 1 *(specify)* $	Benefit 2 *(specify)* $	NET $	P.W. January 2007	Cumulative Present Worth
0	2007	-		-	-	-	-	-	-	-	-
1	2008	-		-	-	30,500,170	-	-	30,500,170	26,640,030	26,640,030
2	2009	226,335	0.55	252,074	-	478,409	-	-	478,409	390,525	27,030,554
3	2010	231,541	0.56	254,358	-	485,898	-	-	485,898	370,690	27,401,244
4	2011	236,866	0.58	263,947	-	500,814	-	-	500,814	357,073	27,758,317
5	2012	242,788	0.61	276,734	-	519,522	-	-	519,522	346,179	28,104,496
6	2013	248,858	0.63	288,150	-	537,008	-	-	537,008	334,421	28,438,918
7	2014	255,079	0.67	304,133	-	559,212	-	-	559,212	325,467	28,764,385
8	2015	261,456	0.69	313,266	-	574,722	-	-	574,722	312,611	29,076,995
9	2016	267,992	0.72	329,249	-	597,242	-	-	597,242	303,607	29,380,603
10	2017	274,692	0.75	342,949	-	617,641	-	-	617,641	293,437	29,674,040
11	2018	281,560	0.79	358,932	-	640,491	-	-	640,491	284,386	29,958,426
12	2019	288,599	0.82	372,632	-	661,230	-	-	661,230	274,387	30,232,813
13	2020	295,814	0.85	386,788	-	682,601	-	-	682,601	264,725	30,497,537
14	2021	303,209	0.87	395,921	-	699,130	-	-	699,130	253,397	30,750,934
15	2022	310,789	0.88	402,771	-	713,560	-	-	713,560	241,707	30,992,642
16	2023	318,559	0.90	410,991	-	6,621,001	-	-	6,621,001	2,096,039	33,088,681
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Assumptions & Notes:

-New engines, refurbishment of alternator and BOP
-Includes allowance for rental mobile equipment during refurbishment period
-Fuel costs based on HYDRO price forecast and historical consumption, with an adjustment for improved efficiency of new engines (10%)
-O&M costs based on 75% of historical average
-Assumes partial refurbishment required in 2023 (reflected as replacement cost)

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PROJECT COST / BENEFIT ANALYSIS TEMPLATE

Hardwoods/Stephenville GT's (Options
New Alt/Refurb GT - Option 2
New Alt - Opt2

Note: Costs are shown as positive values;Benefits as negative values

Current Year	**2007**
Present Worth Year	2007
Number of Years in Study	16
Discount Rate	7.0%
Total In-service Project Cost	$ 10,743,124
In-service Year	2008
Other Project Cost ***after*** In-service (if applicable)	
Other Project Year (if applicable)	
Replacement Cost (if applicable)	$ 5,891,452
Replacement Year (if applicable)	2023
Project cost in Ending (**E**) or Beginning (**B**) Year $$	E
O&M costs - 75% Materials, 25% Labour (**75**) or 50% Materials, 50% Labour (**50**) or User (**U**)	50

A	B	C	D	E	F	G	H	I	J	K	L
Year		Annual O&M Cost $	Annual Fuel Price (if applicable)	Annual Fuel Cost $	Other Cost $	Total Costs $	Benefit 1 *(specify)* $	Benefit 2 *(specify)* $	NET $	P.W. January 2007	Cumulative Present Worth
0	2007	-		-	-	-	-	-	-	-	-
1	2008	-		-	-	10,743,124	-	-	10,743,124	9,383,461	9,383,461
2	2009	241,424	0.55	280,083	-	521,507	-	-	521,507	425,705	9,809,165
3	2010	246,977	0.56	282,620	-	529,596	-	-	529,596	404,027	10,213,192
4	2011	252,657	0.58	293,275	-	545,932	-	-	545,932	389,242	10,602,434
5	2012	258,974	0.61	307,482	-	566,456	-	-	566,456	377,453	10,979,888
6	2013	265,448	0.63	320,167	-	585,615	-	-	585,615	364,692	11,344,579
7	2014	272,084	0.67	337,926	-	610,010	-	-	610,010	355,031	11,699,611
8	2015	278,886	0.69	348,074	-	626,960	-	-	626,960	341,025	12,040,635
9	2016	285,859	0.72	365,833	-	651,691	-	-	651,691	331,287	12,371,922
10	2017	293,005	0.75	381,054	-	674,059	-	-	674,059	320,241	12,692,163
11	2018	300,330	0.79	398,813	-	699,143	-	-	699,143	310,428	13,002,591
12	2019	307,838	0.82	414,035	-	721,874	-	-	721,874	299,552	13,302,143
13	2020	315,534	0.85	429,764	-	745,299	-	-	745,299	289,040	13,591,183
14	2021	323,423	0.87	439,912	-	763,335	-	-	763,335	276,668	13,867,850
15	2022	331,508	0.88	447,523	-	779,032	-	-	779,032	263,885	14,131,735
16	2023	339,796	0.90	456,656	-	6,687,904	-	-	6,687,904	2,117,219	16,248,954
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Assumptions & Notes:

-New alternator, refurbishment of engines and BOP
-Includes allowance for rental mobile equipment during refurbishment period
-Fuel costs based on HYDRO price forecast and historical consumption
-O&M costs based on 80% of historical average
-Assumes partial refurbishment required in 2023 (reflected as replacement cost)

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PROJECT COST / BENEFIT ANALYSIS TEMPLATE

Hardwoods/Stephenville GT's (Options

New Unit Complete - Option 3

New Unit - Opt3

Note: Costs are shown as positive values;Benefits as negative values

Current Year	**2007**
Present Worth Year	2007
Number of Years in Study	16
Discount Rate	7.0%
Total In-service Project Cost	$ 37,859,400
In-service Year	2008
Other Project Cost ***after*** In-service (if applicable)	
Other Project Year (if applicable)	
Replacement Cost (if applicable)	$ 2,000,000
Replacement Year (if applicable)	2023
Project cost in Ending (**E**) or Beginning (**B**) Year $$	E
O&M costs - 75% Materials, 25% Labour (**75**) or 50% Materials, 50% Labour (**50**) or User (**U**)	50

A	B	C	D	E	F	G	H	I	J	K	L
Year		**Annual O&M Cost $**	**Annual Fuel Price (if applicable)**	**Annual Fuel Cost $**	**Other Cost $**	**Total Costs $**	**Benefit 1 *(specify)* $**	**Benefit 2 *(specify)* $**	**NET $**	**P.W. January 2007**	**Cumulative Present Worth**
0	2007	-		-	-	-	-	-	-	-	-
1	2008	-		-	-	37,859,400	-	-	37,859,400	33,067,866	33,067,866
2	2009	211,246	0.55	252,074	-	463,320	-	-	463,320	378,208	33,446,074
3	2010	216,105	0.56	254,358	-	470,462	-	-	470,462	358,914	33,804,987
4	2011	221,075	0.58	263,947	-	485,023	-	-	485,023	345,814	34,150,802
5	2012	226,602	0.61	276,734	-	503,336	-	-	503,336	335,394	34,486,196
6	2013	232,267	0.63	288,150	-	520,417	-	-	520,417	324,090	34,810,285
7	2014	238,074	0.67	304,133	-	542,207	-	-	542,207	315,569	35,125,855
8	2015	244,026	0.69	313,266	-	557,292	-	-	557,292	303,130	35,428,985
9	2016	250,126	0.72	329,249	-	579,376	-	-	579,376	294,525	35,723,510
10	2017	256,379	0.75	342,949	-	599,328	-	-	599,328	284,737	36,008,246
11	2018	262,789	0.79	358,932	-	621,721	-	-	621,721	276,051	36,284,298
12	2019	269,359	0.82	372,632	-	641,990	-	-	641,990	266,403	36,550,701
13	2020	276,093	0.85	386,788	-	662,881	-	-	662,881	257,077	36,807,777
14	2021	282,995	0.87	395,921	-	678,916	-	-	678,916	246,070	37,053,848
15	2022	290,070	0.88	402,771	-	692,841	-	-	692,841	234,689	37,288,537
16	2023	297,322	0.90	410,991	-	2,708,312	-	-	2,708,312	857,382	38,145,919
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Assumptions & Notes:

-New complete unit
-Does not include allowance for rental mobile equipment during refurbishment period
-Fuel costs based on HYDRO price forecast and historical consumption, with an adjustment for improved efficiency of new engines (10%)
-O&M costs based on 70% of historical average
-Allowance for major maintenance included in 2023 (reflected as replacement cost)

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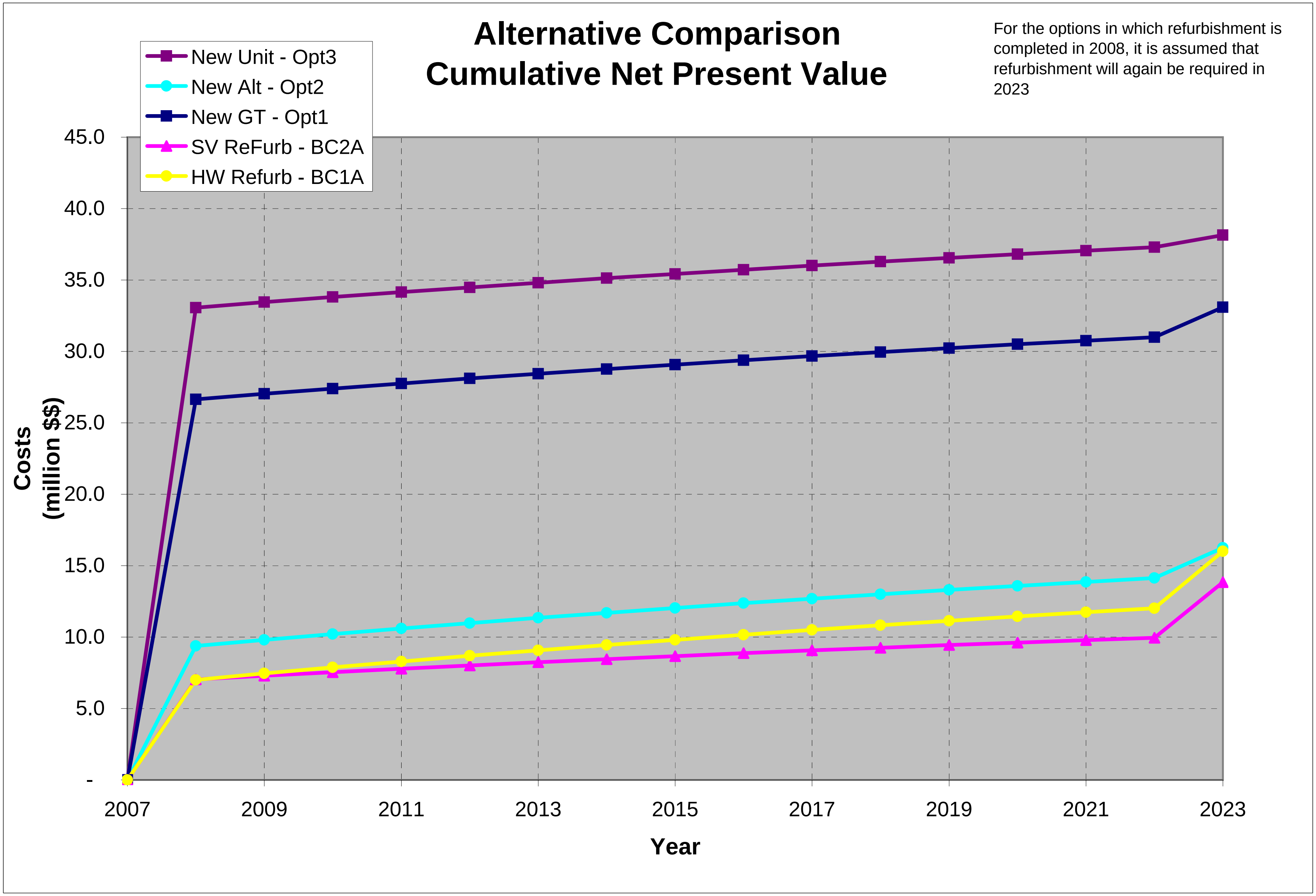
Alternative Comparison
Cumulative Net Present Value
For the options in which refurbishment is completed in 2008, it is assumed that refurbishment will again be required in 2023
New Unit - Opt3
New Alt - Opt2
New GT - Opt1
SV ReFurb - BC2A
HW Refurb - BC1A
Costs (million $$)
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40.0
35.0
30.0
25.0
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5.0
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2007
2009
2011
2013
2015
2017
2019
2021
2023
Year

Hardwoods/Stephenville GT's (Options Subcase 1)

Alternative Comparison

Cumulative Net Present Value

To The Year

2023

Alternatives	Cumulative Net Present Value (CPW)	CPW Difference between Alternative and the Least Cost Alternative
Hardwoods Refurb - Base Case 1A	16,010,747	2,167,979
Stephenville Refurb - Base Case 2A	13,842,768	0
New GT/Refurb Alt - Option 1	33,088,681	19,245,913
New Alt/Refurb GT - Option 2	16,248,954	2,406,186
New Unit Complete - Option 3	38,145,919	24,303,151

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Project Cost/Benefit Analysis Template

Home Page

Current year
2007

Project Title	Hardwoods/Stephenville GT's (Options Subcase 2)
Project In-Service Year	2008
Number of Years in Study Analysis	16
Discount Rate	7.0%
Present Worth Year	2007

(costs are present worthed to January of that year)

Print Home Page

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PROJECT COST / BENEFIT ANALYSIS TEMPLATE

Hardwoods/Stephenville GT's (Options
Hardwoods Refurb - Base Case 1A
HW ReFurb - BC1A

Note: Costs are shown as positive values;Benefits as negative values

Current Year	**2007**
Present Worth Year	2007
Number of Years in Study	16
Discount Rate	7.0%
Total In-service Project Cost	$ 8,017,554
In-service Year	2008
Other Project Cost ***after*** In-service (if applicable)	
Other Project Year (if applicable)	
Replacement Cost (if applicable)	$ 55,639,618
Replacement Year (if applicable)	2023
Project cost in Ending (**E**) or Beginning (**B**) Year $$	E
O&M costs - 75% Materials, 25% Labour (**75**) or 50% Materials, 50% Labour (**50**) or User (**U**)	50

A	B	C	D	E	F	G	H	I	J	K	L
Year		Annual O&M Cost $	Annual Fuel Price (if applicable)	Annual Fuel Cost $	Other Cost $	Total Costs $	Benefit 1 *(specify)* $	Benefit 2 *(specify)* $	NET $	P.W. January 2007	Cumulative Present Worth
0	2007	-		-	-	-	-	-	-	-	-
1	2008	-		-	-	8,017,554	-	-	8,017,554	7,002,842	7,002,842
2	2009	271,602	0.55	280,083	-	551,685	-	-	551,685	450,339	7,453,181
3	2010	277,849	0.56	282,620	-	560,469	-	-	560,469	427,579	7,880,760
4	2011	284,240	0.58	293,275	-	577,514	-	-	577,514	411,760	8,292,520
5	2012	291,346	0.61	307,482	-	598,827	-	-	598,827	399,024	8,691,544
6	2013	298,629	0.63	320,167	-	618,796	-	-	618,796	385,355	9,076,899
7	2014	306,095	0.67	337,926	-	644,021	-	-	644,021	374,826	9,451,725
8	2015	313,747	0.69	348,074	-	661,821	-	-	661,821	359,987	9,811,712
9	2016	321,591	0.72	365,833	-	687,423	-	-	687,423	349,451	10,161,163
10	2017	329,631	0.75	381,054	-	710,685	-	-	710,685	337,641	10,498,804
11	2018	337,871	0.79	398,813	-	736,685	-	-	736,685	327,097	10,825,901
12	2019	346,318	0.82	414,035	-	760,353	-	-	760,353	315,520	11,141,421
13	2020	354,976	0.85	429,764	-	784,741	-	-	784,741	304,336	11,445,757
14	2021	363,851	0.87	439,912	-	803,763	-	-	803,763	291,321	11,737,077
15	2022	372,947	0.88	447,523	-	820,470	-	-	820,470	277,922	12,014,999
16	2023	382,271	0.90	456,656	-	56,478,545	-	-	56,478,545	17,879,661	29,894,660
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Assumptions & Notes:

-Refurbishment of engines, alternator and BOP
-Includes allowance for rental mobile equipment during refurbishment period
-Fuel costs based on HYDRO price forecast and historical consumption
-O&M costs based on 90% of historical average
-Assumes complete new unit required in 2023 (reflected as replacement cost)

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PROJECT COST / BENEFIT ANALYSIS TEMPLATE

Hardwoods/Stephenville GT's (Options
Stephenville Refurb - Base Case 2A
SV ReFurb - BC2A

Note: Costs are shown as positive values;Benefits as negative values

Current Year	**2007**
Present Worth Year	2007
Number of Years in Study	16
Discount Rate	7.0%
Total In-service Project Cost	$ 8,050,389
In-service Year	2008
Other Project Cost ***after*** In-service (if applicable)	
Other Project Year (if applicable)	
Replacement Cost (if applicable)	$ 55,639,618
Replacement Year (if applicable)	2023
Project cost in Ending (**E**) or Beginning (**B**) Year $$	E
O&M costs - 75% Materials, 25% Labour (**75**) or 50% Materials, 50% Labour (**50**) or User (**U**)	50

A	B	C	D	E	F	G	H	I	J	K	L
Year		**Annual O&M Cost $**	**Annual Fuel Price (if applicable)**	**Annual Fuel Cost $**	**Other Cost $**	**Total Costs $**	**Benefit 1 *(specify)* $**	**Benefit 2 *(specify)* $**	**NET $**	**P.W. January 2007**	**Cumulative Present Worth**
0	2007	-		-	-	-	-	-	-	-	-
1	2008	-		-	-	8,050,389	-	-	8,050,389	7,031,522	7,031,522
2	2009	157,035	0.61	165,489	-	322,524	-	-	322,524	263,276	7,294,797
3	2010	160,647	0.62	167,109	-	327,755	-	-	327,755	250,043	7,544,840
4	2011	164,341	0.64	172,778	-	337,120	-	-	337,120	240,362	7,785,202
5	2012	168,450	0.67	180,337	-	348,787	-	-	348,787	232,412	8,017,614
6	2013	172,661	0.69	187,356	-	360,018	-	-	360,018	224,201	8,241,814
7	2014	176,978	0.73	197,075	-	374,053	-	-	374,053	217,702	8,459,517
8	2015	181,402	0.75	203,014	-	384,417	-	-	384,417	209,097	8,668,614
9	2016	185,937	0.79	212,733	-	398,670	-	-	398,670	202,664	8,871,278
10	2017	190,586	0.82	221,372	-	411,958	-	-	411,958	195,718	9,066,996
11	2018	195,350	0.86	231,091	-	426,441	-	-	426,441	189,345	9,256,341
12	2019	200,234	0.89	239,730	-	439,964	-	-	439,964	182,569	9,438,910
13	2020	205,240	0.92	248,099	-	453,339	-	-	453,339	175,813	9,614,723
14	2021	210,371	0.94	254,038	-	464,409	-	-	464,409	168,323	9,783,046
15	2022	215,630	0.96	258,357	-	473,988	-	-	473,988	160,556	9,943,602
16	2023	221,021	0.98	264,567	-	56,125,206	-	-	56,125,206	17,767,803	27,711,405
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Assumptions & Notes:

-Refurbishment of engines, alternator and BOP
-Includes allowance for rental mobile equipment during refurbishment period
-Fuel costs based on HYDRO price forecast and historical consumption
-O&M costs based on 90% of historical average
-Assumes complete new unit required in 2023 (reflected as replacement cost)

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PROJECT COST / BENEFIT ANALYSIS TEMPLATE

Hardwoods/Stephenville GT's (Options
New GT/Refurb Alt - Option1
New GT - Opt1

Note: Costs are shown as positive values;Benefits as negative values

Current Year	**2007**
Present Worth Year	2007
Number of Years in Study	16
Discount Rate	7.0%
Total In-service Project Cost	$ 30,500,170
In-service Year	2008
Other Project Cost ***after*** In-service (if applicable)	
Other Project Year (if applicable)	
Replacement Cost (if applicable)	$ 15,788,505
Replacement Year (if applicable)	2023
Project cost in Ending (**E**) or Beginning (**B**) Year $$	E
O&M costs - 75% Materials, 25% Labour (**75**) or 50% Materials, 50% Labour (**50**) or User (**U**)	50

A	B	C	D	E	F	G	H	I	J	K	L
Year		Annual O&M Cost $	Annual Fuel Price (if applicable)	Annual Fuel Cost $	Other Cost $	Total Costs $	Benefit 1 *(specify)* $	Benefit 2 *(specify)* $	NET $	P.W. January 2007	Cumulative Present Worth
0	2007	-		-	-	-	-	-	-	-	-
1	2008	-		-	-	30,500,170	-	-	30,500,170	26,640,030	26,640,030
2	2009	226,335	0.55	252,074	-	478,409	-	-	478,409	390,525	27,030,554
3	2010	231,541	0.56	254,358	-	485,898	-	-	485,898	370,690	27,401,244
4	2011	236,866	0.58	263,947	-	500,814	-	-	500,814	357,073	27,758,317
5	2012	242,788	0.61	276,734	-	519,522	-	-	519,522	346,179	28,104,496
6	2013	248,858	0.63	288,150	-	537,008	-	-	537,008	334,421	28,438,918
7	2014	255,079	0.67	304,133	-	559,212	-	-	559,212	325,467	28,764,385
8	2015	261,456	0.69	313,266	-	574,722	-	-	574,722	312,611	29,076,995
9	2016	267,992	0.72	329,249	-	597,242	-	-	597,242	303,607	29,380,603
10	2017	274,692	0.75	342,949	-	617,641	-	-	617,641	293,437	29,674,040
11	2018	281,560	0.79	358,932	-	640,491	-	-	640,491	284,386	29,958,426
12	2019	288,599	0.82	372,632	-	661,230	-	-	661,230	274,387	30,232,813
13	2020	295,814	0.85	386,788	-	682,601	-	-	682,601	264,725	30,497,537
14	2021	303,209	0.87	395,921	-	699,130	-	-	699,130	253,397	30,750,934
15	2022	310,789	0.88	402,771	-	713,560	-	-	713,560	241,707	30,992,642
16	2023	318,559	0.90	410,991	-	16,518,055	-	-	16,518,055	5,229,193	36,221,835
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Assumptions & Notes:

-New engines, refurbishment of alternator and BOP
-Includes allowance for rental mobile equipment during refurbishment period
-Fuel costs based on HYDRO price forecast and historical consumption, with an adjustment for improved efficiency of new engines (10%)
-O&M costs based on 75% of historical average
-Assumes replacement of alternator required in 2023 (reflected as replacement cost)

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PROJECT COST / BENEFIT ANALYSIS TEMPLATE

Hardwoods/Stephenville GT's (Options
New Alt/Refurb GT - Option 2
New Alt - Opt2

Note: Costs are shown as positive values;Benefits as negative values

Current Year	**2007**
Present Worth Year	2007
Number of Years in Study	16
Discount Rate	7.0%
Total In-service Project Cost	$ 10,743,124
In-service Year	2008
Other Project Cost ***after*** In-service (if applicable)	
Other Project Year (if applicable)	
Replacement Cost (if applicable)	$ 44,824,213
Replacement Year (if applicable)	2023
Project cost in Ending (**E**) or Beginning (**B**) Year $$	E
O&M costs - 75% Materials, 25% Labour (**75**) or 50% Materials, 50% Labour (**50**) or User (**U**)	50

A	B	C	D	E	F	G	H	I	J	K	L
Year		Annual O&M Cost $	Annual Fuel Price (if applicable)	Annual Fuel Cost $	Other Cost $	Total Costs $	Benefit 1 *(specify)* $	Benefit 2 *(specify)* $	NET $	P.W. January 2007	Cumulative Present Worth
0	2007	-		-	-	-	-	-	-	-	-
1	2008	-		-	-	10,743,124	-	-	10,743,124	9,383,461	9,383,461
2	2009	241,424	0.55	280,083	-	521,507	-	-	521,507	425,705	9,809,165
3	2010	246,977	0.56	282,620	-	529,596	-	-	529,596	404,027	10,213,192
4	2011	252,657	0.58	293,275	-	545,932	-	-	545,932	389,242	10,602,434
5	2012	258,974	0.61	307,482	-	566,456	-	-	566,456	377,453	10,979,888
6	2013	265,448	0.63	320,167	-	585,615	-	-	585,615	364,692	11,344,579
7	2014	272,084	0.67	337,926	-	610,010	-	-	610,010	355,031	11,699,611
8	2015	278,886	0.69	348,074	-	626,960	-	-	626,960	341,025	12,040,635
9	2016	285,859	0.72	365,833	-	651,691	-	-	651,691	331,287	12,371,922
10	2017	293,005	0.75	381,054	-	674,059	-	-	674,059	320,241	12,692,163
11	2018	300,330	0.79	398,813	-	699,143	-	-	699,143	310,428	13,002,591
12	2019	307,838	0.82	414,035	-	721,874	-	-	721,874	299,552	13,302,143
13	2020	315,534	0.85	429,764	-	745,299	-	-	745,299	289,040	13,591,183
14	2021	323,423	0.87	439,912	-	763,335	-	-	763,335	276,668	13,867,850
15	2022	331,508	0.88	447,523	-	779,032	-	-	779,032	263,885	14,131,735
16	2023	339,796	0.90	456,656	-	45,620,665	-	-	45,620,665	14,442,334	28,574,070
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Assumptions & Notes:

-New alternator, refurbishment of engines and BOP
-Includes allowance for rental mobile equipment during refurbishment period
-Fuel costs based on HYDRO price forecast and historical consumption
-O&M costs based on 80% of historical average
-Assumes replacement of engines/turbines required in 2023 (reflected as replacement cost)

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PROJECT COST / BENEFIT ANALYSIS TEMPLATE

Hardwoods/Stephenville GT's (Options
New Unit Complete - Option 3
New Unit - Opt3

Note: Costs are shown as positive values;Benefits as negative values

Current Year	**2007**
Present Worth Year	2007
Number of Years in Study	16
Discount Rate	7.0%
Total In-service Project Cost	$ 37,859,400
In-service Year	2008
Other Project Cost ***after*** In-service (if applicable)	
Other Project Year (if applicable)	
Replacement Cost (if applicable)	$ 2,000,000
Replacement Year (if applicable)	2023
Project cost in Ending (**E**) or Beginning (**B**) Year $$	E
O&M costs - 75% Materials, 25% Labour (**75**) or 50% Materials, 50% Labour (**50**) or User (**U**)	50

A	B	C	D	E	F	G	H	I	J	K	L
Year		**Annual O&M Cost $**	**Annual Fuel Price (if applicable)**	**Annual Fuel Cost $**	**Other Cost $**	**Total Costs $**	**Benefit 1 *(specify)* $**	**Benefit 2 *(specify)* $**	**NET $**	**P.W. January 2007**	**Cumulative Present Worth**
0	2007	-		-	-	-	-	-	-	-	-
1	2008	-		-	-	37,859,400	-	-	37,859,400	33,067,866	33,067,866
2	2009	211,246	0.55	252,074	-	463,320	-	-	463,320	378,208	33,446,074
3	2010	216,105	0.56	254,358	-	470,462	-	-	470,462	358,914	33,804,987
4	2011	221,075	0.58	263,947	-	485,023	-	-	485,023	345,814	34,150,802
5	2012	226,602	0.61	276,734	-	503,336	-	-	503,336	335,394	34,486,196
6	2013	232,267	0.63	288,150	-	520,417	-	-	520,417	324,090	34,810,285
7	2014	238,074	0.67	304,133	-	542,207	-	-	542,207	315,569	35,125,855
8	2015	244,026	0.69	313,266	-	557,292	-	-	557,292	303,130	35,428,985
9	2016	250,126	0.72	329,249	-	579,376	-	-	579,376	294,525	35,723,510
10	2017	256,379	0.75	342,949	-	599,328	-	-	599,328	284,737	36,008,246
11	2018	262,789	0.79	358,932	-	621,721	-	-	621,721	276,051	36,284,298
12	2019	269,359	0.82	372,632	-	641,990	-	-	641,990	266,403	36,550,701
13	2020	276,093	0.85	386,788	-	662,881	-	-	662,881	257,077	36,807,777
14	2021	282,995	0.87	395,921	-	678,916	-	-	678,916	246,070	37,053,848
15	2022	290,070	0.88	402,771	-	692,841	-	-	692,841	234,689	37,288,537
16	2023	297,322	0.90	410,991	-	2,708,312	-	-	2,708,312	857,382	38,145,919
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Assumptions & Notes:

-New complete unit
-Does not include allowance for rental mobile equipment during refurbishment period
-Fuel costs based on HYDRO price forecast and historical consumption, with an adjustment for improved efficiency of new engines (10%)
-O&M costs based on 70% of historical average
-Allowance for major maintenance included in 2023 (reflected as replacement cost)

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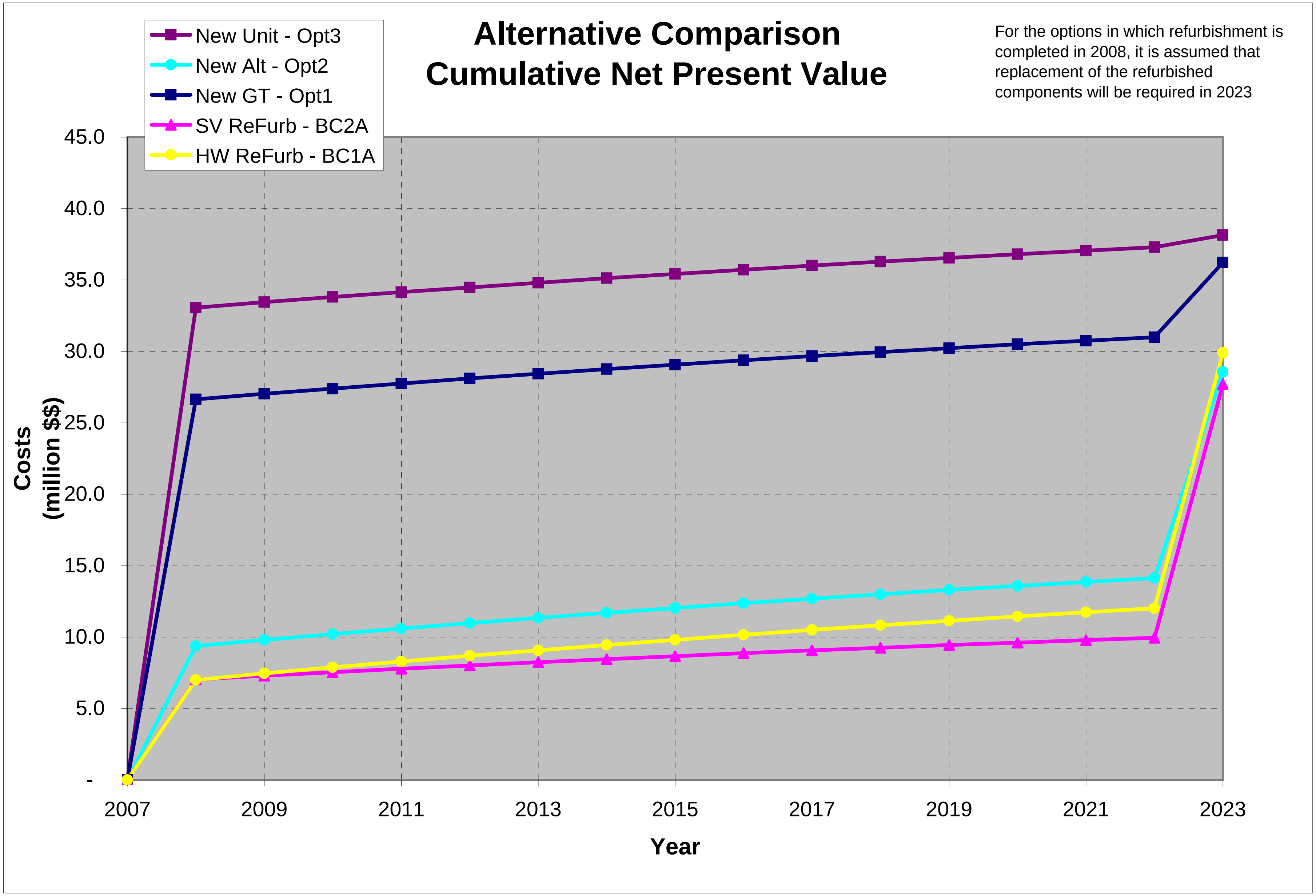
Alternative Comparison
Cumulative Net Present Value
For the options in which refurbishment is completed in 2008, it is assumed that replacement of the refurbished components will be required in 2023
New Unit - Opt3
New Alt - Opt2
New GT - Opt1
SV ReFurb - BC2A
HW ReFurb - BC1A
Costs (million $$)
45.0
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35.0
30.0
25.0
20.0
15.0
10.0
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2007
2009
2011
2013
2015
2017
2019
2021
2023
Year

Hardwoods/Stephenville GT's (Options Subcase 2)

Alternative Comparison

Cumulative Net Present Value
To The Year
2023

Alternatives	Cumulative Net Present Value (CPW)	CPW Difference between Alternative and the Least Cost Alternative
Hardwoods Refurb - Base Case 1A	29,894,660	2,183,255
Stephenville Refurb - Base Case 2A	27,711,405	0
New GT/Refurb Alt - Option1	36,221,835	8,510,430
New Alt/Refurb GT - Option 2	28,574,070	862,665
New Unit Complete - Option 3	38,145,919	10,434,515

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APPENDIX 13
PHOTOGRAPHS
HARDWOODS AND STEPHENVILLE GAS TURBINE FACILITIES

HWD-001 – Gas Turbine

Newfoundland and Labrador Hydro
St. John's, NL

HARDWOODS

HWD-002 – Air Inlet & Exhaust

HWD-004 – Air Inlet

HWD-003 – Air Inlet


HWD-005 – Air Inlet


HWD-006 – Air Inlet


HWD-007 – Air Inlet


HWD-008 – Air Inlet


HWD-009 – Air Inlet


HWD-010 – Air Inlet


HWD-011 – Exhaust Stack


HWD-012 – Exhaust Stack


HWD-013 – Exhaust Stack


HWD-014 – Exhaust Stack

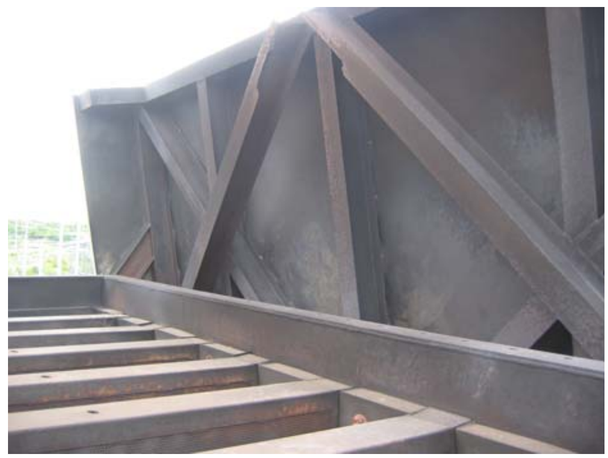

HWD-015 – Exhaust Stack

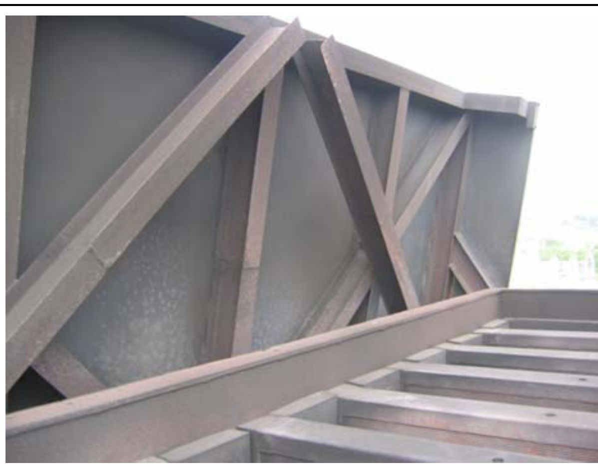

HWD-016 – Exhaust Stack


HWD-017 – Exhaust Stack


HWD-018– Exhaust Stack


HWD-019 – Exhaust Stack


HWD-020– Exhaust Stack


HWD-021– Exhaust Stack


HWD-022– Exhaust Stack

HWD-023– Lube Oil Glycol Cooler

HWD-024– Lube Oil Glycol Cooler

HWD-025 – Engine & Turbine Enclosure

HWD-026 – Engine & Turbine Enclosure

HWD-027 – Alternator Enclosure

HWD-028 – Oil Storage Area

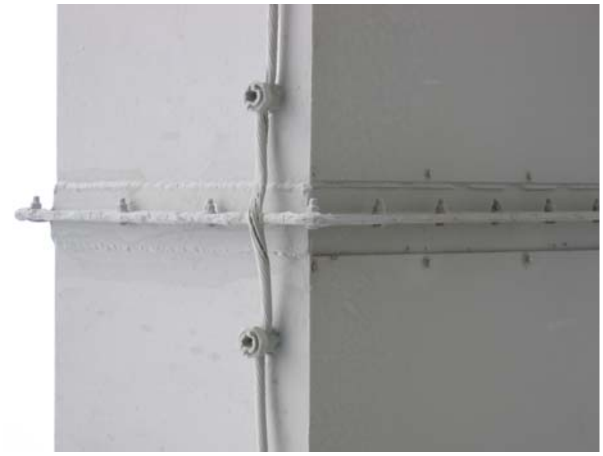
HWD-029 – Oil Storage Area

HWD-030 – Oil Storage Tank

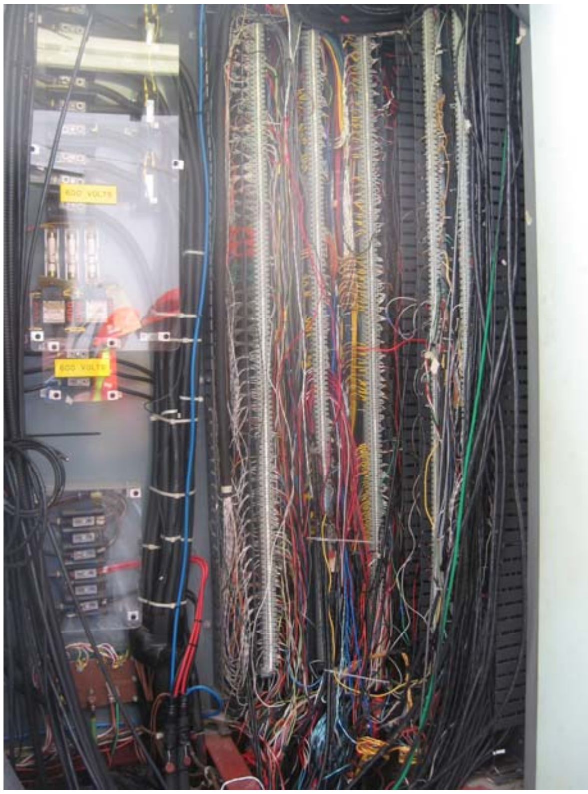
HWD-031 – Oil Storage Tank

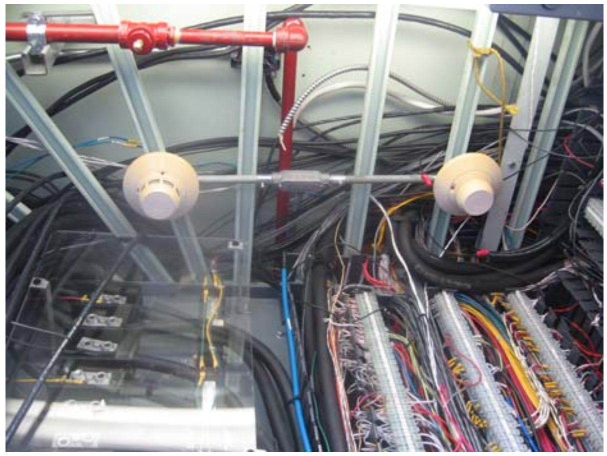
HWD-032 – 13.8 kV Bus Duct

HWD-033 – 13.8 kV Bus Duct



HWD-034 – 13.8 kV Bus Duct


HWD-035 – Control Module Cabling


HWD-036 – Control Module Cabling


HWD-037 – Control Module Building


HWD-038 – Control Module Building

HWD-039 – Fuel Unloading Building

HWD-040 – Fuel Unloading Building


HWD-041 – Fuel Unloading Building


HWD-042 – Fuel Unloading Building


HWD-043 – Fuel Forwarding Building

HWD-044 – Fuel Forwarding Building

HWD-046 – Auxiliary Module Building

HWD-048 – HV Switchgear Building

HWD-045 – Fuel Forwarding Building

HWD-047 – Maintenance Building

SVL-001 – Gas Turbine

Newfoundland and Labrador Hydro
St. John's, NL

STEPHENVILLE


SVL-002 – Air Inlet


SVL-003 – Air Inlet


SVL-004 – Air Inlet


SVL-005 – Air Inlet


SVL-006 – Air Inlet


SVL-007 – Air Inlet

SVL-008 – Exhaust Stack

SVL-009 – Exhaust Stack

SVL-010 – Exhaust Stack

SVL-011 – Exhaust Stack

SVL-012 – Lube Oil Glycol Cooler

SVL-013 – Lube Oil Glycol Cooler

SVL-014 – Lube Oil Glycol Cooler

SVL-015 – Engine & Turbine Enclosure

SVL-016 – Engine & Turbine Enclosure


SVL-017 – Engine & Turbine Enclosure


SVL-018– Engine & Turbine Enclosure


SVL-019 – Alternator Enclosure


SVL-020– Alternator Glycol Cooler


SVL-021– Alternator Glycol Cooler


SVL-022– Alternator Glycol Cooler


SVL-023– Alternator Glycol Cooler


SVL-024–Oil Storage Area


SVL-025 – Oil Storage Area


SVL-026 – Oil Storage Area


SVL-027 – Oil Storage Piping


SVL-028 – HV Switchgear Building

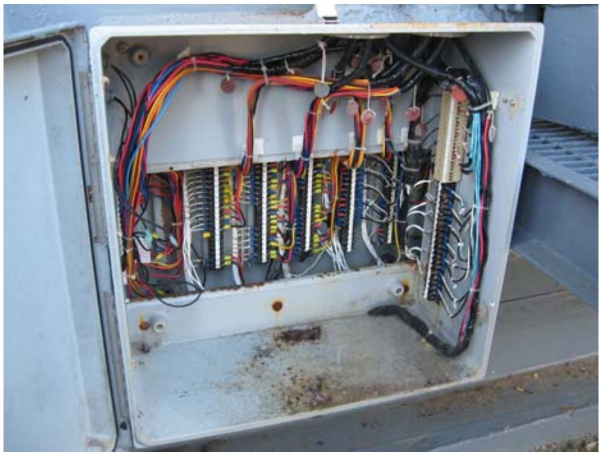
SVL-029 – 13.8 kV Bus Duct

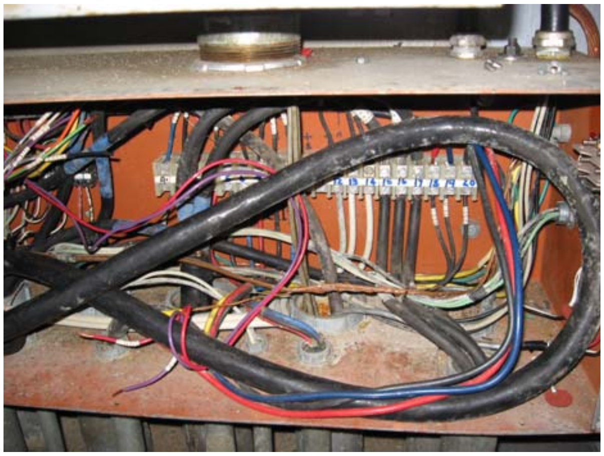
SVL-030 – 13.8 kV Bus Duct

SVL-031 – Battery Chargers

SVL-032 – Protection Relays

SVL-033 – 15 kV Transformer Cabling


SVL-034 – GT Junction Box


SVL-035 – GT Junction Box


SVL-036 – Control Building


SVL-037 – Control Building


SVL-038 – Control Building


SVL-039 – Control Building

SVL-040 – Fuel Forwarding Building

SVL-041 – Fuel Forwarding Building

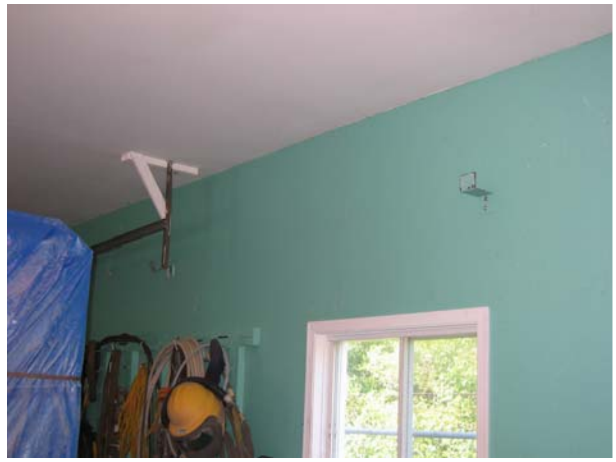
SVL-042 – Fuel Forwarding Building

SVL-043 – Fuel Forwarding Building

SVL-044 – Parts Storage Shed

SVL-045 – Parts Storage Shed

SVL-046 – Parts Storage Shed



SVL-047 – Parts Storage Shed

SVL-048 – Waste Oil Storage Shed

SVL-049 – Waste Oil Storage Shed