newfoundland labrador
hydro
a nalcor energy company

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www.nlh.nl.ca

April 2, 2013

The Board of Commissioners of Public Utilities
Prince Charles Building
120 Torbay Road, P.O. Box 21040
St. John's, NL
A1A 5B2

ATTENTION: Ms. Cheryl Blundon
Director of Corporate Services & Board Secretary

Dear Ms. Blundon:

Re: An Application by Newfoundland and Labrador Hydro (Hydro) pursuant to Subsection 41(3) of the Act for approval of the Restoration of Unit 1 Turbine and Generator at the Holyrood Thermal Generating Station

On January 11, 2013 there was a major winter storm which caused widespread power outages to the Island Interconnected System. Unit 1 at Hydro's Holyrood generating station received significant damage on that day and has been out of service since. Hydro has completed an assessment of the damage and has commenced, but has not yet completed, an investigation into the specific cause of the damage that occurred.

Unit 1 requires refurbishment so that it can be brought back into service hence Hydro is seeking the Board's approval of this capital project to effect these repairs. The contractor that has been providing the engineering support to assess the damage and determine the refurbishment work required is available and on site at present to carry out this work provided that a contractual commitment can be made to commence it without delay. Having this contractor commence this work immediately will avoid demobilization and mobilization costs, thus making the job less costly, and will shorten the length of time for which the unit will remain unavailable to provide generation to the Island Interconnected System.

Enclosed please find the original and eight copies of the Application, supporting affidavit, draft order and Appendices to the Application, the Project description and justification. Due to the aforementioned time-sensitivity of this project, Hydro is respectfully requesting that the Application be considered by the Board on a priority basis. Hydro will be contacting the potential Intervenors in this regard.

...2/

Should you have any questions, please contact the undersigned.

Yours truly,

NEWFOUNDLAND AND LABRADOR HYDRO

Geoffrey P. Young
Senior Legal Counsel

GPY/jc

cc: Gerard Hayes – Newfoundland Power
Paul Coxworthy – Stewart McKelvey Stirling Scales
Thomas Johnson – Consumer Advocate
Dean Porter – Poole Althouse

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

AND IN THE MATTER OF an Application by Newfoundland and Labrador Hydro pursuant to Subsection 41(3) of the *Act*, for the approval of the refurbishment of Unit 1 Turbine and Generator at the Holyrood Thermal Generating Station.

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

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

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

2. This is an application for the approval of the refurbishment of Unit 1 Generator at Hydro's Holyrood Thermal Generating Station (HTGS). The Unit 1 Generator suffered significant damage on January 11, 2013 at a time when a major winter storm had caused widespread damage and power interruptions to the Island Interconnected System, including damage to the Holyrood Terminal Station. An investigation as to the specific cause of the damage to the Unit 1 Generator is in progress.

3. The HTGS is an essential part of the Island Interconnected System, with three units providing a total capacity of 490 MW, representing approximately one-third of Hydro's Island Interconnected System generating capacity. The HTGS comprises three units. In 1971, Stage I was completed bringing on line two generating units, Units 1 and 2, and in 1979, Stage II was completed bringing on line Unit 3. The HTGS will remain a key component of Hydro's generation fleet until 2020. Unit 1 is out of service at present and cannot be placed back in service until the proposed work has been completed.

4. The nature of the damage suffered to Unit 1 Generator is as described in detail in the project justification document. The work required to repair the Unit includes the preliminary engineering which took place in Phases 1 and 2 of the project. The detailed scope of work required to address the issues identified during the preliminary engineering stages is also in the attached project justification document, and includes:

Completing turbine rotor and diaphragm repairs;

Replacing the diaphragm inter stage packing; and

Replacing the turbine bearings and connect the lubrication oil piping.

5. The completion of these refurbishments to Unit 1 are required to ensure that Hydro can continue to provide safe, reliable and adequate service from this essential facility. In particular, the expeditious return to service of Unit 1 is

required to ensure that the unit is available to permit Hydro to take outages to some of its other generating facilities on the Avalon Peninsula. This includes work with regard to the Unit 3 Turbine Valves Overhaul at Holyrood, approved by the Board in Order No. P.U. 4(2013).

6. The estimated cost of this project is $13,154,700.

7. The Applicant submits that the proposed capital works and expenditures are necessary to ensure that this generation facility can continue to provide service which is reasonable safe and adequate and just and reasonable as required by Section 37 of the *Act*.

8. Therefore, Hydro makes Application that the Board make an Order approving, pursuant to Subsection 41(3) of the *Act*, the capital expenditure of $13,154,700 for the the refurbishment of Unit 1 at HTGS as set out in this Application and in the attached project description and justification document.

DATED at St. John's, in the Province of Newfoundland and Labrador, this 2nd day of April, 2013.

Geoffrey P. Young
Counsel for the Applicant
Newfoundland and Labrador Hydro
500 Columbus Drive P.O. Box 12400
St. John's, Newfoundland and Labrador
A1B 4K7
Telephone: (709) 737-1277
Facsimile: (709) 737-1782

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

AND IN THE MATTER OF an Application by Newfoundland and Labrador Hydro pursuant to Subsection 41(3) of the *Act*, for the approval of the refurbishment of Unit 1 Turbine and Generator at the Holyrood Thermal Generating Station.

AFFIDAVIT

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

1. I am Vice-President, Newfoundland and Labrador Hydro, the Applicant named in the attached Application.
2. I have read and understand the foregoing Application.
3. I have personal knowledge of the facts contained therein, except where otherwise indicated, and they are true to the best of my knowledge, information and belief.

SWORN at St. John's in the)
Province of Newfoundland and)
Labrador)
this 2nd day of April 2013,)
before me:)

Barrister – Newfoundland and Labrador	Robert J. Henderson

(DRAFT ORDER)
NEWFOUNDLAND AND LABRADOR
BOARD OF COMMISSIONERS OF PUBLIC UTILITIES

AN ORDER OF THE BOARD

NO. P.U. __ (2013)

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

AND

IN THE MATTER OF an application by Newfoundland and Labrador Hydro for approval approval of the refurbishment of Unit 1 at the Holyrood Thermal Generating Station, pursuant to Subsection 41(3) of the Act.

WHEREAS Newfoundland and Labrador Hydro ("Hydro") is a corporation continued and existing under the *Hydro Corporation Act, 2007*, is a public utility within the meaning of the Act, and is subject to the provisions of the *EPCA;* and

WHEREAS Subsection 41(3) of the Act requires that a public utility not proceed with the construction, purchase or lease of improvements or additions to its property where:

a) the cost of construction or purchase is in excess of $50,000; or
b) the cost of the lease is in excess of $5,000 in a year of the lease,

without prior approval of the Board; and

WHEREAS Unit 1 of Hydro's Holyrood Thermal Generating Station (Holyrood) suffered significant damage during a major winter storm that occurred on January 11, 2013; and

WHEREAS on April 2, 2013 Hydro filed an application with the Board seeking approval for a capital project to effect refurbishment and repairs to Unit 1 of Holyrood in the amount of $13,154,700; and

WHEREAS in Order Nos. P.U. 2(2013) and P.U. 4(2013) the Board approved Hydro's 2013 Capital Budget; and

WHEREAS the Board approved supplementary 2013 capital expenditures in

(i) Order No. P.U. 1(2013) in the amount of $284,100 for the refurbishment of the stop logs at the Burnt Dam Spillway; and

WHEREAS the Board is satisfied that the 2013 supplemental capital expenditure for the refurbishment of Unit 1 at Holyrood is necessary to allow Hydro to provide service and facilities which are reasonably safe and adequate and just and reasonable.

<u>IT IS THEREFORE ORDERED THAT:</u>

1. The capital expenditure of $13,154,700 for the refurbishment of Unit 1 at the Holyrood Thermal Generating Station is approved.

2. Hydro shall pay all expenses of the Board arising from this Application.

DATED at St. John's, Newfoundland and Labrador, this day of , .

Project Title:	Unit 1 Turbine and Generator Restoration
Location:	Holyrood
Category:	Generation - Thermal
Definition:	Other
Classification:	Normal

Introduction:

The Holyrood Thermal Generating Station (Holyrood) plays an essential role in the Island Interconnected System. With three generating units providing a total capacity of 490 MW (466 MW net), the plant represents approximately one third of Hydro's total Island Interconnected System generating capacity. From October to May, at least one unit at Holyrood, and most often two or three units, is required to reliably meet the power demand of the system. In addition to providing a large amount of energy to the Island Interconnected System as part of regular annual operations, Holyrood also provides energy security to the Island Interconnected System during years of low water inflows into the island hydro generation reservoirs. On average, the plant produces approximately 1,300 GWh per year and during dry conditions, may be required to produce 3,000 GWh per year.

Holyrood was constructed in two stages. In 1971, Stage I was completed bringing on line two generating units, Units 1 and 2, each capable of producing 150 MW. In 1979, Stage II was completed bringing on line one additional generating unit, Unit 3, capable of producing 150 MW. In 1988 and 1989, Units I and 2 were up-rated to 170 MW.

Holyrood Unit 1 experienced an in-service failure with damage on January 11, 2013. At that time, a major winter storm caused damage and wide-spread power interruptions to the Island Interconnected System, including damage to the terminal station located at Holyrood. An investigation into the specific root cause of the damage to Unit 1 is in progress and a separate report will be prepared when the investigation is complete. The root cause investigation process has been overseen by a third party consultant, System Improvements, Inc. An executive summary prepared by System Improvements, Inc. of the root cause analysis work completed to March 13 is located in Appendix A of this report. The investigation to date has determined that the damage to the unit was caused by a failure of the turbine and generator lubricating oil system to maintain sufficient oil to the bearings when the unit shut down in response to an issue in the Holyrood terminal station. It has also identified that a major contributor to the loss of lubrication oil was a failure of the DC oil pump set to deliver sufficient lubricating oil when the two AC oil pumps shut down due to the disturbance on the power system. The investigation has identified that weekly testing of the DC oil pump set was completed as required consistent with the original equipment manufacturer guidelines. However, it was found that the test procedure lacked a check that would have identified the particular failure experienced within the pump set which made the pump unable to deliver the required oil flow to the bearings. The test procedure has now been enhanced. Hydro will submit the final root cause analysis report to the Board of Commissioners of Public Utilities (Board) when it is complete.

Project Description:

This project is necessary to refurbish Holyrood Unit 1 following the in-service failure on January 11, 2013.

The project includes a Preliminary Assessment (Phase 1), a Full Assessment (Phase 2), and Restoration (Phase 3). Alstom Power, the existing turbine and generator maintenance service provider, was engaged to complete the Phase 1 and Phase 2 work, with oversight by Hydro's engineering team and AMEC, a third party consultant. Phase 1 and Phase 2 are complete. The results of Phase 2 were used to develop the detailed scope of work, schedule and estimate for Phase 3.

Immediately following the in-service failure on January 11, 2013, Phase 1 inspections were initiated. During this phase, visual inspections were completed on the turbine and generator bearings. The turbine and generator has a total of five babbit-style bearings. Two bearings are located on the generator and the remaining three bearings are located on the steam turbine. The top sections of the bearing housings, including the vibration and temperature probes, were removed to perform visual inspections on the bearings, rotor journal surfaces, and oil deflector seals. Clearance measurements were also taken on the bearings and oil deflector seals. Extensive babbit damage was noted on all five bearings during the inspection as a result of a loss of lubrication oil during the failure event. In addition, heat stress marks were noted on the turbine and generator rotor bearing journal surfaces as shown in Figure 1 below. The generator collector housing assembly and end casings were also removed to perform preliminary visual inspections on the generator rotor, stator windings, and the brush gear assembly. Damage was noted on the brush gear assembly as a result of excessive vibration during the failure event. Phase 1 was completed on February 1, 2013. Following the completion of Phase 1, Alstom submitted an inspection report to Hydro that is located in Appendix B of this report. The cost to execute Phase 1 is included in Table 2 located on page 8.

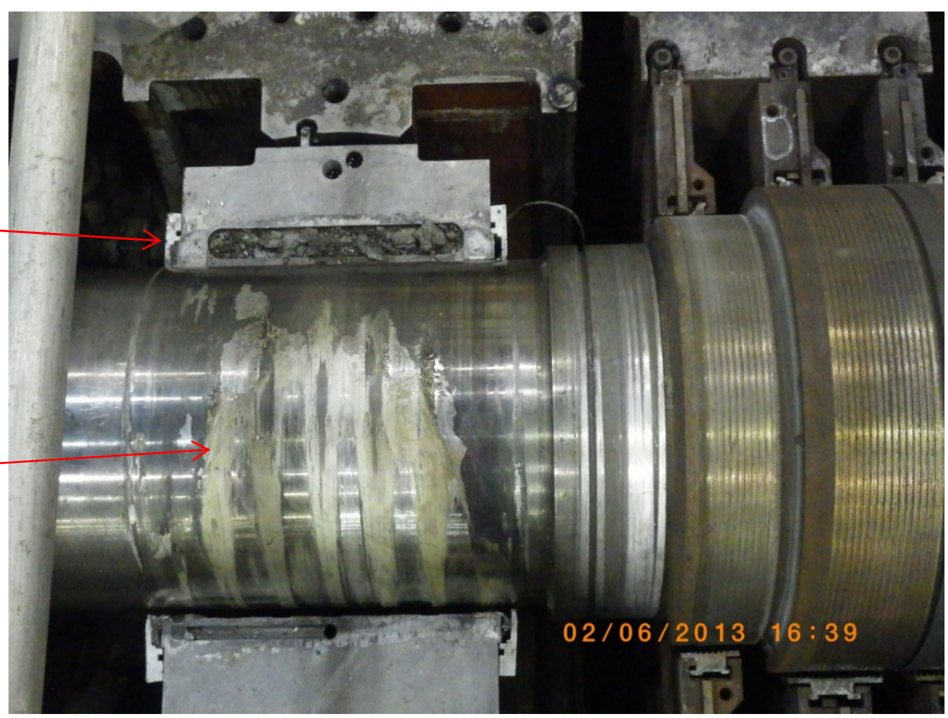


Figure 1. Typical Bearing and Journal Damage

Following the completion of Phase 1, it was decided to proceed with Phase 2 to execute a complete assessment of the damage to Unit 1. During Phase 2, the generator rotor was uncoupled from the turbine rotor, removed from the generator, and a series of non-destructive electrical tests were conducted on the rotor and stator. The testing was completed and no issues were identified, with the exception of carbon dust buildup on the generator rotor internal windings which had been present prior to the incident. The generator rotor was also installed in a portable lathe at Holyrood to check for run out. Run out is a measurement of radial and axial movement on a shaft during rotation. There were no significant run out issues noted during the inspection.

Simultaneously, the turbine was also disassembled to complete an internal inspection. The turbine consists of three sections that are referred to as the high pressure (HP), intermediate pressure (IP), and low pressure (LP) sections. Initially, scaffolding was erected around the turbine to remove the external insulation, steam piping, and the turbine casing bolts.

Following the completion of this work, the turbine inner and outer top section casings were removed to expose the turbine rotor and diaphragms for an internal inspection.

The turbine rotor consists of moving blades whereas the diaphragms consist of stationary blades that are situated between the turbine rotor stages that guide the steam to flow over the rotor blades. The diaphragms are also equipped with wear components known as inter stage packing and spill strips that prevent steam leakage across the turbine rotor stages during operation.

Following the removal of the inner and outer top section turbine casings, it was discovered that the turbine rotor had moved radially and axially towards the generator during the failure event on January 11, 2013. This movement resulted in contact between the rotor and the diaphragm spill strips and inter stage packing, causing damage and clearance issues (see Figures 2 and 3 below). The rotor was then removed from the turbine and installed in a portable lathe to check for run out. There were no significant run out issues noted during the inspection. However, numbers 2 and 3 bearing journal surfaces had heat stress and hardness issues that will require machining and stress relieving during Phase 3. After the turbine rotor was removed, the turbine diaphragms were also removed and non-destructive testing was completed on the diaphragms to check for cracks. No cracks were discovered.

Figure 2. Steam Turbine HP Bottom Casing with Rotor Removed

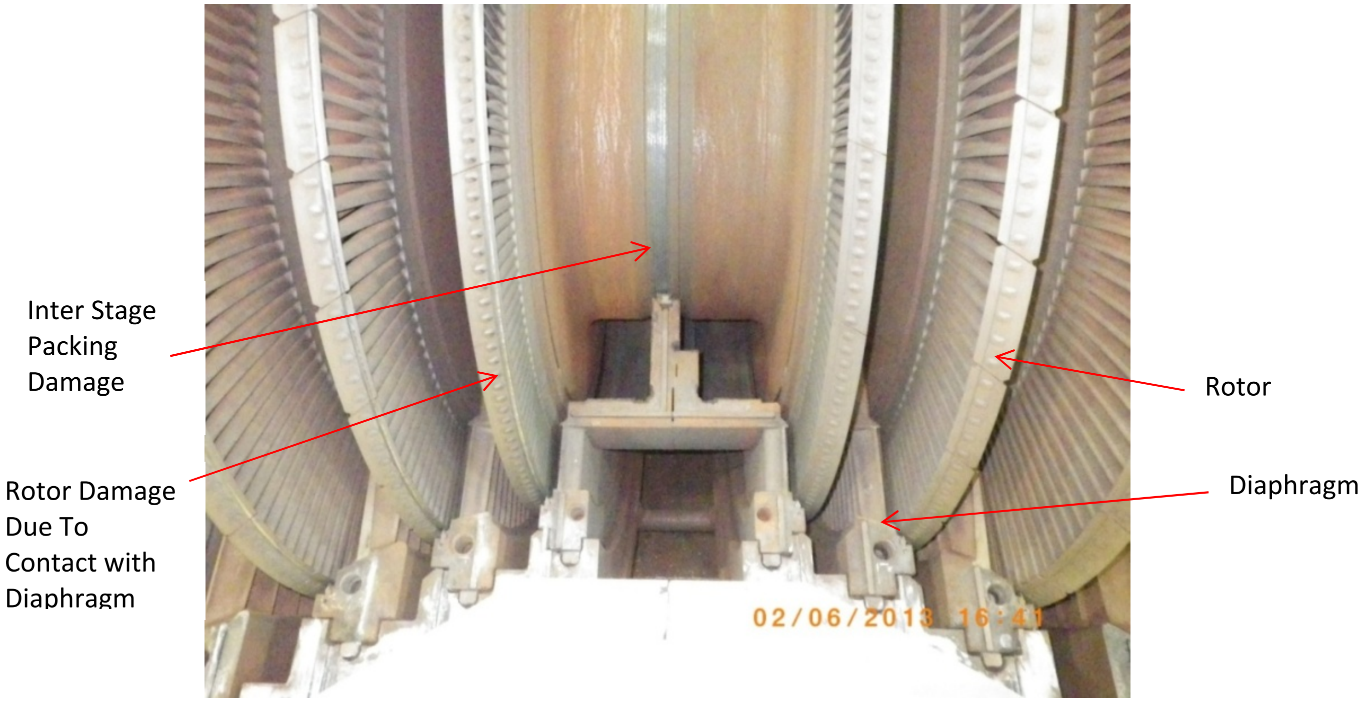


Figure 3. Steam Turbine Rotor & Diaphragms

The Unit 1 turbine and generator lubrication system was also inspected during Phase 2. The lubrication system consists of a dedicated lube oil tank, heat exchangers, two AC oil pumps, one DC oil pump, valves and piping. During the event on January 11, 2013, the oil system became contaminated with bearing babbit material as a result of a loss of lubrication on the turbine and generator bearings. The oil was removed from the tank and the tank was then cleaned internally. The lube oil pumps were removed from the tank, disassembled, and inspected for damage. In addition, the lube oil heat exchangers were removed from the tank, cleaned, and hydrostatically tested in order to check for leaks. Phase 2 was completed on March 16, 2013. Following the completion of Phase 2, Alstom submitted inspection reports to Hydro that are located in Appendix C of this report. A separate condition assessment report was also provided by AMEC. This report is located in Appendix D. The cost to execute Phase 2 is included in Table 2 located on page 8.

Phase 3 of the project includes the following repair and reassembly scope of work, based on the Phase 2 findings presented in Appendix C:

1. Complete turbine rotor and diaphragm repairs;
2. Repair or replace the failed components of the oil lubrication system including the DC lubrication oil pump set;
3. Re-install the lubrication oil pumps and heat exchangers into the lube oil tank and fill the tank with oil;
4. Clean and flush the turbine and generator lubrication oil system and re-install the lube oil piping;
5. Replace the diaphragm inter stage packing on HP, IP, and LP turbine sections;
6. Remove and replace the HP and IP section turbine diaphragm spill strips;
7. Re-install the lower turbine diaphragms;
8. Complete a laser alignment of the lower turbine diaphragms;
9. Re-install the turbine rotor;
10. Replace the turbine bearings and connect the lubrication oil piping;
11. Re-install the HP turbine inner and outer top section casings;
12. Re-install the IP turbine inner and outer top section casings;
13. Re-install the LP turbine inner top section casing;
14. Re-install the LP turbine outer top section hood;
15. Re-install the crossover steam piping;
16. Re-install the HP turbine control valve actuator, linkages, and rack and pinion assembly;
17. Complete repairs to the turbine and generator front standard;
18. Insulate the turbine;
19. Jack up the generator casing (one side at a time) and replace the shims;
20. Re-install the generator rotor;
21. Replace the generator bearings and connect the lubrication oil piping;
22. Replace the instrumentation on all five bearings;
23. Re-install the generator hydrogen seals and end casings;

24. Install the generator slip rings, brushes, and the collector housing;
25. Complete a generator alignment;
26. Replace damaged instrumentation components; and
27. Commissioning and startup of Unit 1 turbine and generator.

Budget Estimate:

The detailed repair and re-assembly scope of work that will be completed during Phase 3 is provided above. The cost of executing this highly specialized work is estimated to be $7.3 M. During this repair and re-assembly phase, an extensive number of tradespeople, technical specialists, sub-contractors, and special tools and equipment will be required on site to complete the work over an eleven week period.

Table 1 provides the budget estimate for this project.

Table 1: Project Budget Estimate

Project Cost:*($ x1,000)*	**2013**	**2014**	**Beyond**	**Total**
Material Supply	450.0	0.0	0.0	450.0
Labour	679.0	0.0	0.0	679.0
Consultant	249.9	0.0	0.0	249.9
Contract Work	9,178.8	0.0	0.0	9,178.8
Other Direct Costs	5.6	0.0	0.0	5.6
Interest and Escalation	478.9	0.0	0.0	478.9
Contingency	2,112.6	0.0	0.0	2,112.6
TOTAL	**13,154.7**	**0.0**	**0.0**	**13,154.7**

Table 2: Project Budget Estimate by Phase

Project Cost: *($ X 1,000)*	**Phase 1**	**Phase 2**	**Phase 3**	**Total**
Material Supply	8.7	7.9	433.4	450.0
Labor	57.6	167.9	453.5	679.0
Consultant	40.1	132.7	77.0	249.9
Contract Work	309.2	1,551.7	7,317.9	9,178.8
Other Direct Cost	0	0	5.6	5.6
Interest and Escalation	0	0	478.9	478.9
Contingency	0	0	2,112.6	2,112.6
TOTAL	**415.6**	**1,860.2**	**10,878.9**	**13,154.7**[1]

[1]A portion of the budget estimate above may be recovered by subsequent insurance claim proceedings by Hydro at a later date.

Operating Experience:

Holyrood has been in operation since 1970 and operates under a seasonal regime. Full generating capacity is required during the winter months and no generation output has been required during the summer for many years. During the spring and fall seasons, the plant generation output varies but is normally less than the rated plant capacity. In late spring when less power generation capacity is required, Unit 3 is converted to synchronous condenser mode of operation. Synchronous condensing is required during the summer to provide voltage support.

Project Justification:

As previously discussed, the Holyrood plant plays a critical role in the safe reliable electricity supply to the Island Interconnected System. Holyrood Unit 1 is required to be restored to service to provide its 170 MW capacity to the system to meet system peak load requirements. It is essential that it is available for the 2014 peak winter season to prevent the risk of service interruption to customers. It is also required on a timely basis to enable the other units at Holyrood to be removed from service to complete critical maintenance and capital upgrades this summer and early fall prior to the 2013/2014 operating season. While Unit 1 is not available during the current operating season, the other two units must remain in service or available to meet customer service requirements. In addition while this unit is under repair planned work cannot proceed on Units 2 and 3 because required space, equipment and some critical trades people are committed to Unit 1.

Project Schedule:

Table 3 provides the anticipated schedule for Phase 3 of this project.

Table 3: Project Schedule

Activity	Start Date	End Date
Phase 3	April 2013	June 2013
Commissioning and Start-up	June 2013	June 2013
Project Documentation and Closeout	June 2013	July 2013

SYSTEM IMPROVEMENTS, INC.

TECHNIQUES FOR PERFORMANCE IMPROVEMENT

238 South Peters Road, Suite 301 **Phone: (865) 539-2139**
Knoxville, Tennessee 37923-5224 **Fax: (865) 539-4335**

Date: March 28, 2013

To: John MacIsaac
VP Project Exe & Tech Services
Executive Leadership
Nalcor Energy

From: Kenneth Turnbull
TapRooT® Associate

Subject: Executive Summary of TapRooT® Root Cause Analysis
Holyrood Turbine Bearing Failure

On March 12 and 13, 2013, I facilitated a TapRooT® Root Cause Investigation with your investigation team. We assembled an Event and Causal Factor Chart (SnapCharT®) using information that the team had already collected through inspections, review of plant control system historical data, interviews and procedure reviews. The team did an excellent job in obtaining information. I have included a copy of the SnapCharT® prepared as of the information available on March 12 and 13, 2013.

In summary, on the morning of January 11th, 2013 an electrical fault was experienced in the Holyrood switchyard during severe weather conditions. Holyrood Unit 1 was generating at the time and its protection systems removed it from service in response to this fault condition. The analysis completed to the date of my visit indicates that after the two AC pumps shut down the DC lubricating oil pump failed to provide required oil to the bearings during the unit shut down. The team's analysis also indicates that Newfoundland and Labrador Hydro (Hydro) followed ongoing test procedure requirements developed and designed for this pump. However, it was also found that the procedure did not specify a test sequence which would detect the type of failure experienced.

Unit 1 has three separate lubricating oil pumps, all designed to be capable of delivering sufficient lubricating oil. The overall system failed to deliver the pressure needed on January 11, 2013, resulting in a loss of lubricating oil to the bearings. This failure is what the team selected as the incident to perform a root cause analysis on. Root cause analysis is performed to develop corrective actions to manage the risk of future failures.

There are two AC lubricating oil pumps. The primary or unit service AC pump is powered directly from the generator. As it is designed to do, the primary pump shut down with the generating unit. The secondary, or station service powered, AC pump shut down due to a severe depression in system voltage which was experienced during the switchyard fault event on January 11. The control circuitry for the secondary pump calls for a re-start based on both loss of the primary AC pump and the loss of lube oil pressure. The secondary pump re-started three minutes after the unit tripped. In the absence of both AC pumps, the lubricating oil system was dependent solely on the unit's third pump, the DC pump.

The plant's control system historical data shows that the DC pump started and ran in response to the loss of the two AC pumps and the resultant loss of oil pressure. While the DC pump started as required, it did not deliver sufficient pressure to provide adequate lubricating oil to the bearings.

The TapRooT® System looks at the failure and finds Causal Factors which are safeguards that could, would, or should have significantly lowered the risk of the failure. The team found four risk causal factors:

1. The standby AC pump did not restart in a timely manner after shutting down due to a voltage depression.

2. Although it started and ran as designed, the DC pump did not maintain oil pressure.

3. The unit underwent a major overhaul inspection program in 2012 (nine year frequency) but this effort did not detect that the DC pump was not delivering sufficient pressure.

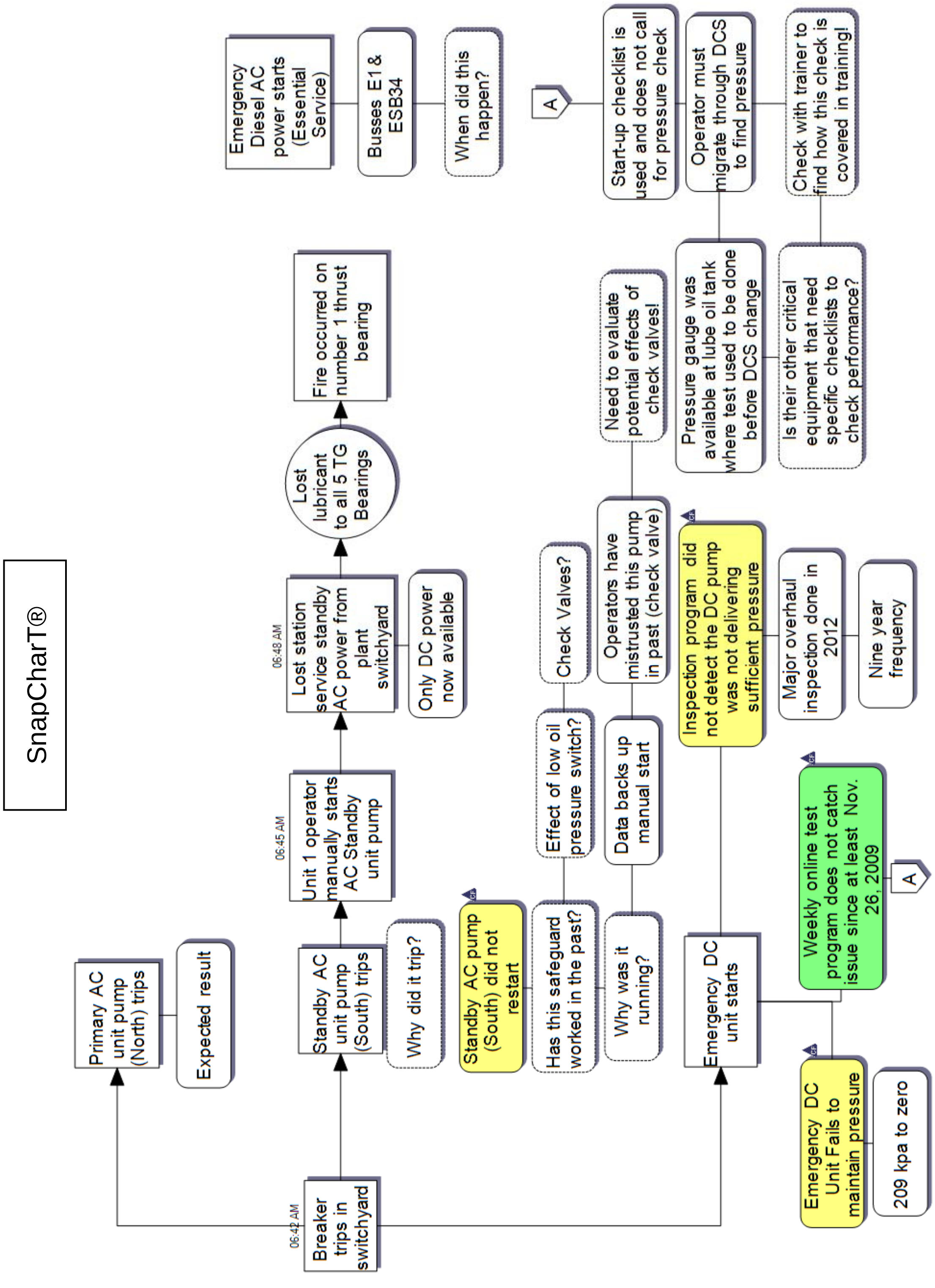
4. The weekly online test program, although regularly executed, did not detect that the DC pump was not delivering sufficient pressure.

At the time of our investigation, information required to complete a root cause analysis on causal factors 1 through 3 was still in the process of being collected.

The team was able to perform a root cause analysis using the TapRooT® Root Cause Tree® on causal factor number 4 as there was sufficient detailed information available. Results of the root cause analysis indicated that the start-up procedure that was used to test the DC pump lacked sufficient steps to verify pressure and flow to the bearings. In addition, displays of pressure where the test was performed could be improved. The manufacturer of the lubricating oil system did not provide a means to monitor lubricating oil flow.

Following this incident, corrective actions have been developed by Hydro to have operators write a new lubricating oil pump test procedure, make displays readily available, and provide training associated with the new procedure. A survey will also be made of other critical equipment to ensure test procedures and displays are adequate.

At this time, the root cause analysis on causal factors one through three above is ongoing and, depending on the outcome of the analyses, more corrective actions are likely be taken by Hydro to manage the risk of future lubricating oil system failures.


SnapCharT®
06:42 AM
Breaker trips in switchyard
Primary AC unit pump (North) trips
Expected result
Standby AC unit pump (South) trips
Why did it trip?
06:45 AM
Unit 1 operator manually starts AC Standby unit pump
06:48 AM
Lost station service standby AC power from plant switchyard
Only DC power now available
Lost lubricant to all 5 TG Bearings
Fire occurred on number 1 thrust bearing
Emergency Diesel AC power starts (Essential Service)
Busses E1 & ESB34
When did this happen?
Standby AC pump (South) did not restart
Has this safeguard worked in the past?
Effect of low oil pressure switch?
Check Valves?
Why was it running?
Data backs up manual start
Operators have mistrusted this pump in past (check valve)
Need to evaluate potential effects of check valves!
Emergency DC unit starts
Inspection program did not detect the DC pump was not delivering sufficient pressure
Major overhaul inspection done in 2012
Nine year frequency
Pressure gauge was available at lube oil tank where test used to be done before DCS change
Is their other critical equipment that need specific checklists to check performance?
A
Start-up checklist is used and does not call for pressure check
Operator must migrate through DCS to find pressure
Check with trainer to find how this check is covered in training!
Weekly online test program does not catch issue since at least Nov. 26, 2009
A
Emergency DC Unit Fails to maintain pressure
209 kpa to zero

Holyrood Unit 1 Forced Outage
Results of Phase 1 Inspection and Recommendation for Further Inspection

The following is a summary of the work performed by Alstom Power during the Initial Inspection Phase (Phase 1) of the Forced Outage on Unit 1, GE Turbine S/N 940310, located at the NALCOR Energy Holyrood Station, Holyrood, NL. The summary outlines the work performed in each section of the unit and the findings in each section. For purposes of this inspection, Alstom was instructed to commence inspection from the Rear of the Machine (Collector End of the Generator) to the Front of the Machine (Front Standard).

Prior to Alstom's commencement of work on Jan. 21, 2013, the customer completed the following work:

1. LOTO and all necessary permits
2. Erect scaffold under Generator for access to the Belly doors and bushing box
3. Remove Collector Housing, Collector Brushes, Brush Rigging
4. Shaft Grounding Brushes
5. Cleanup of the Mezzanine floor under the Generator and the Turbine Deck, including the Front Standard area
6. Drain oil and water from the Generator and Bushing Box
7. Drain Main Lube Oil Tank
8. Remove insulation from around the N1 upper packing gland

Summary of work and Findings (Jan 21, 2013 thru Jan 25, 2013):

Collector rings:

Visual Inspection of the Collector Rings and Brush Rigging was completed. No sign of rubbing between the collector rings and the Brush Rigging. A number of Brushes were damaged.

Collector End of Generator:

The Collector End of the Generator was disassembled down to the horizontal joint for visual inspection. The following are the findings:

Outer Air Seal – The air seal shows light rubbing.

Holyrood Unit 1 Forced Outage
Results of Phase 1 Inspection and Recommendation for Further Inspection

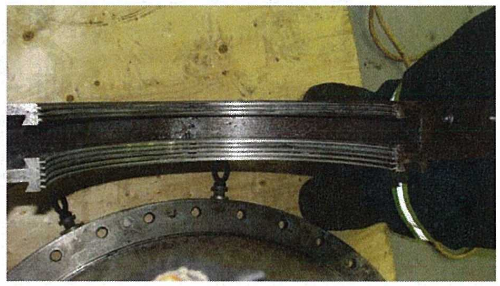
T5 air seal Bottom

T5 air seal Top

T5 Outer Oil Deflector – The T5 outer oil deflector, Upper and Lower half, is heavily rubbed and will need to be repaired. The lower oil deflector clearance is "0" and the upper oil deflector as found clearance was .113" and the as built upper clearance in 2012 was .022". This indicates .091" wear in the deflector.

T5 oil deflector U/H

Holyrood Unit 1 Forced Outage
Results of Phase 1 Inspection and Recommendation for Further Inspection



T5 oil deflector L/H

T5 oil deflector L/H and Seal Area prior to removal of deflector

T5 Bearing – A feeler check of the clearance between the shaft and the T5 journal showed a clearance of .070", and the as built bearing clearance vertical was .018", showing .052" wear in the bearing bore. T5 Bearing oil bore, indicates the shaft to be approximately .068" low. This number is approximated as the closing oil bores at T5 were not recorded at the last or previous outages on this unit. This number is based on the assumption the oil bores are nearly equal L, R, B. The as found was L=11.233", R=11.268", B=11.182".

T5 Bearing U/H

Holyrood Unit 1 Forced Outage
Results of Phase 1 Inspection and Recommendation for Further Inspection

T5 Bearing U/H

T5 Bearing L/H

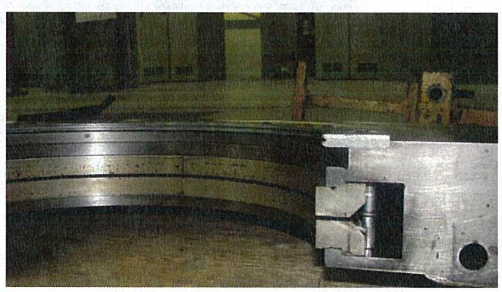
T5 Bearing L/H and Journal as found Left Side

Holyrood Unit 1 Forced Outage
Results of Phase 1 Inspection and Recommendation for Further Inspection

T5 Bearing L/H and Journal as found Right side

CE Hydrogen Seal Casing – the radial alignment of the H2 seal casing was taken and compared to the as assembled alignment prior to disassembly of the casing. Feeler check of the casing shows the shaft is .044" low in the bore. Casing should be centered to the shaft. L=.192", T=.2325", R=.184" are the as found readings. The gas side oil deflector upper half and lower half are heavily rubbed. The H2 Seals has slight rubbing on the I.D. and seals can be moved in the bore.

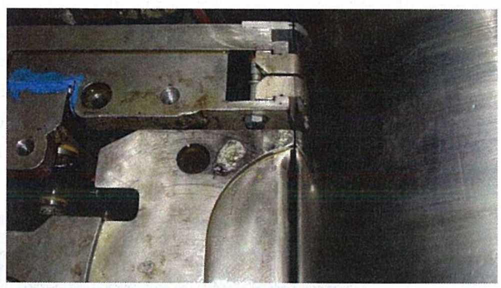
CE Hydrogen Seal Casing prior to removal



CE H2 Seal Casing U/H hard rub on Gas side Oil Deflector

Holyrood Unit 1 Forced Outage
Results of Phase 1 Inspection and Recommendation for Further Inspection

CE H2 Seal Casing L/H Right Side

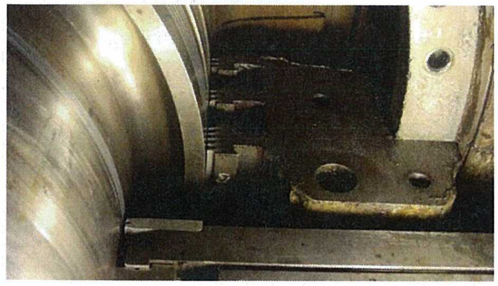


CE H2 Seal Casing L/H Left Side

T5 Inner Oil Deflector – Prior to removal, a feeler check for clearance between the upper half and the shaft showed .113" vertical clearance. The as assembled vertical clearance in 2012 was .022", this is a delta of .091". Upper and Lower deflector is wiped.

T5 Inner Oil Deflector U/H prior to removal

Holyrood Unit 1 Forced Outage
Results of Phase 1 Inspection and Recommendation for Further Inspection



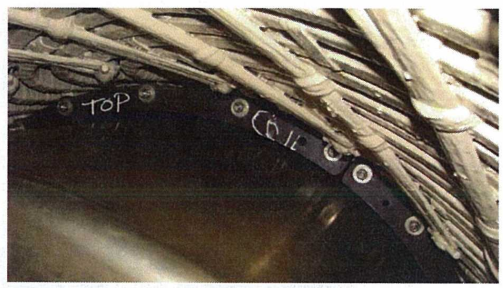
T5 Inner oil deflector L/H left side

T5 inner oil Deflector shaft area showing rub

T5 Inner Oil Deflector L/H right side

CE Air Gap Baffle – the air gap baffle does not appear to have rubbed, no signs of rubbing on the retaining rings or the baffles themselves.

CE Air Gap Baffle Left side



CE Air Gap Baffle Top

CE Air Gap Baffle Right side

CE Fan Blades – the CE Fan Blades do not appear to have rubbed and are in good condition as is the Fan Shrouds. The Fan Blade radial clearances were recorded prior to removal of the shrouds or the blades. The lower blade radial clearance was found to be .032" as compared to the as assembled clearance in 2012 of .075". This indicated the shaft is low in the bore at the CE .043". This compares favorably with the H2 Seal Casing and reasonable with the T5 Bearing clearance and the rotor position.

Holyrood Unit 1 Forced Outage
Results of Phase 1 Inspection and Recommendation for Further Inspection

CE Fan Tips Typical

CE Fan Tips at Disassembly Left side

CE Fan Tips at Disassembly Right side

CE End Windings – No visual indication of Mechanical or Electrical damage to the CE ending windings due to this event. There are signs of greasing, indicating some bar movement has occurred.

Holyrood Unit 1 Forced Outage
Results of Phase 1 Inspection and Recommendation for Further Inspection

View of CE End Windings with unit on Half Joint

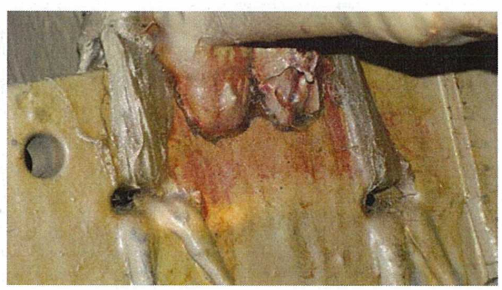
CE End Windings Greasing

CE End Windings Greasing

Holyrood Unit 1 Forced Outage
Results of Phase 1 Inspection and Recommendation for Further Inspection

CE End Windings Greasing

CE End Windings Greasing



CE End Winding Greasing

Holyrood Unit 1 Forced Outage
Results of Phase 1 Inspection and Recommendation for Further Inspection

CE End Winding Greasing

CE End Winding Greasing

CE End Winding Greasing

Holyrood Unit 1 Forced Outage
Results of Phase 1 Inspection and Recommendation for Further Inspection

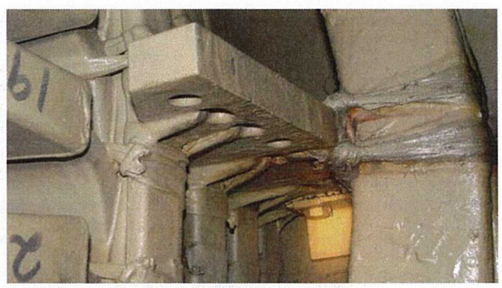
CE End Winding Greasing

CE End Winding Greasing

CE End Winding Greasing

Holyrood Unit 1 Forced Outage
Results of Phase 1 Inspection and Recommendation for Further Inspection

CE End Winding Greasing



CE End Winding Greasing

CE End Winding Greasing

Bushing Box and Belly Bands – visual inspection inside of the Bushing Box does not reveal any visible or electrical damage. There is oil and water in the bottom of the bushing box.

The Belly Bands were visually inspected and found to be in good condition. There were no signs of distress or movement in the Belly Bands by visual inspection.

Holyrood Unit 1 Forced Outage
Results of Phase 1 Inspection and Recommendation for Further Inspection

Bushing Box – Oil and Water in bottom

Bushing Box – Oil and Water in bottom

C-Phase

Holyrood Unit 1 Forced Outage
Results of Phase 1 Inspection and Recommendation for Further Inspection

B-Phase

B-Phase

A-Phase

A-Phase

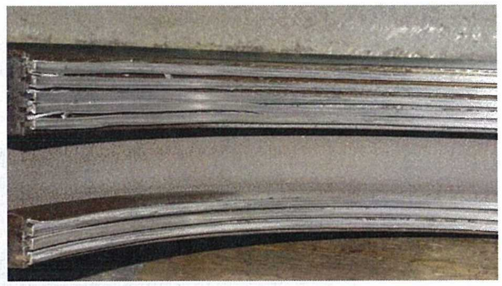
Turbine End of Generator:

The Turbine End of the Generator was disassembled down to the horizontal joint for visual inspection. The following are the findings:

T4 Outer Oil Deflector – The T4 outer oil deflector, Upper and Lower half, is heavily rubbed and will need to be repaired. The lower oil deflector clearance is "0" and the upper oil deflector as found clearance was .145" and the as built upper clearance in 2012 was .024". This indicates .121" wear in oil deflector bore.

T4 Outer Oil Deflector prior to removal

Holyrood Unit 1 Forced Outage
Results of Phase 1 Inspection and Recommendation for Further Inspection



T4 U/H Outer Oil Deflector

T4 U/H Outer Oil Deflector

T4 U/H Outer Oil Deflector

T4 L/H Outer Oil Deflector Left side

T4 L/H Outer Oil deflector Right side

T4 Bearing – A feeler check of the clearance between the shaft and the T4 journal was not recorded due to limited access to the top of the bearing caused by the thrust runner on the Generator Rotor. The 2012 as built bearing clearance vertical was .0167". T4 Bearing oil bore, indicates the shaft to be approximately .103" low. This number is approximated as the closing oil bores at T4 were not recorded at the last or previous outages on this unit. This number is based on the assumption the oil bores are nearly equal L, R, B. The as found was L=9.887", R=9.856", B=9.768".

T4 Bearing U/H

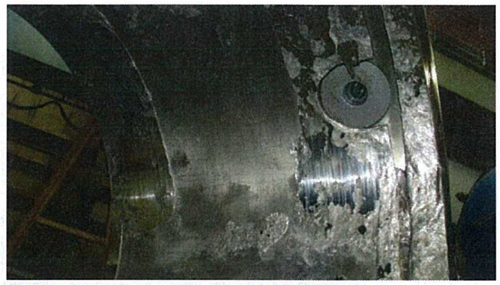
Holyrood Unit 1 Forced Outage
Results of Phase 1 Inspection and Recommendation for Further Inspection

T4 Bearing U/H

T4 Bearing L/H Right side and Journal

T4 Bearing L/H Left side bearing and journal

Holyrood Unit 1 Forced Outage
Results of Phase 1 Inspection and Recommendation for Further Inspection



T4 Bearing U/H

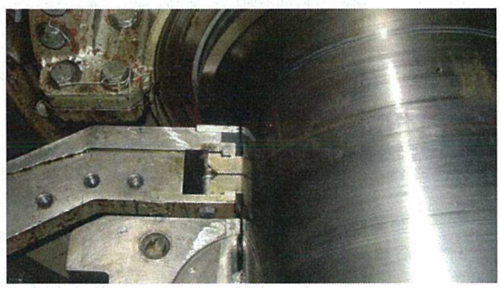
T4 Bearing U/H

TE Hydrogen Seal Casing – the radial alignment of the H2 seal casing was taken and compared to the as assembled alignment prior to disassembly of the casing. Feeler check of the casing shows the shaft is .109" low in the bore. Casing should be centered to the shaft. L=.195", T=.295", R=.177" are the as found readings. The gas side oil deflector upper half and lower half are heavily rubbed. The H2 Seals has slight rubbing on the I.D. and seals can be moved in the bore. The TE H2 Seals had a large gap between the seals and the shaft on initial inspection. The clearance was well above the normal and could have been the source of gas leakage at TE.

Holyrood Unit 1 Forced Outage
Results of Phase 1 Inspection and Recommendation for Further Inspection

TE Hydrogen Seal Casing Prior to removal

TE Hydrogen Seal Casing U/H removed – upper gas side oil seal heavy rub



TE Hydrogen Seal L/H Left side

TE Hydrogen Seal L/H Right Side

Holyrood Unit 1 Forced Outage
Results of Phase 1 Inspection and Recommendation for Further Inspection

TE Hydrogen Seal Journal

T4 Inner Oil Deflector – Prior to removal, a feeler check for clearance between the upper half and the shaft showed .120" vertical clearance. The as assembled vertical clearance in 2012 was .022", this is a delta of .098". Upper and Lower deflector is wiped.

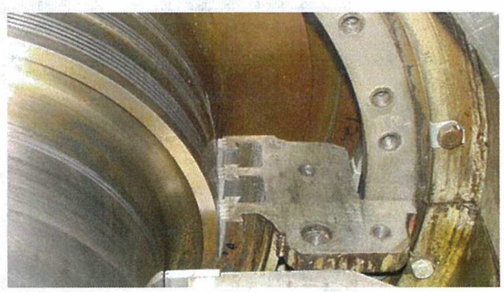
T4 Inner Oil Deflector prior to removal

T4 U/H Inner Oil Deflector removed

Holyrood Unit 1 Forced Outage
Results of Phase 1 Inspection and Recommendation for Further Inspection

T4 U/H Inner Oil Deflector damaged teeth

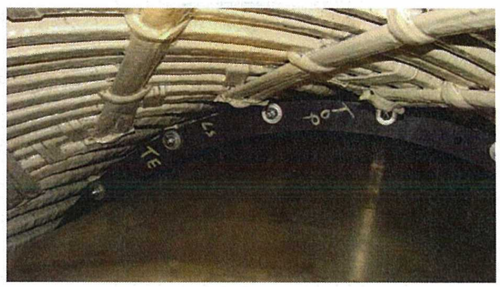
T4 L/H Inner Oil Deflector Left Side



T4 L/H Inner Oil Deflector Right side

TE Air Gap Baffle – the air gap baffle does not appear to have rubbed, no signs of rubbing on the retaining rings or the baffles themselves.

TE Air Gap Baffles Top



TE Air Gap Baffles Top

TE Air Gap Baffles Right Side

TE Fan Blades – the TE Fan Blades do not appear to have rubbed and are in good condition as is the Fan Shrouds. The Fan Blade radial clearances were recorded prior to removal of the shrouds or the blades. The upper blade radial clearance was found to be .202" as compared to the as assembled clearance in 2012 of .097". This indicated the shaft is low in the bore at the TE .105". This compares favorably with the H2 Seal Casing and reasonable with the T5 Bearing clearance and the rotor position.

TE Fan Blades Typical

TE Fan Blades Typical

TE End Windings – No visual indication of Mechanical or Electrical damage to the TE ending windings due to this event. There are signs of greasing, indicating some bar movement has occurred.

TE End Winding Greasing

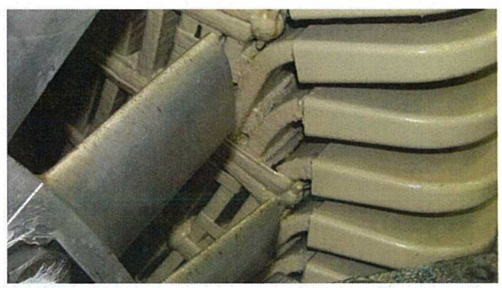
Holyrood Unit 1 Forced Outage
Results of Phase 1 Inspection and Recommendation for Further Inspection

TE End Winding Greasing

TE End Winding Greasing

TE End Winding Greasing

TE End Winding Greasing



TE End Winding Greasing

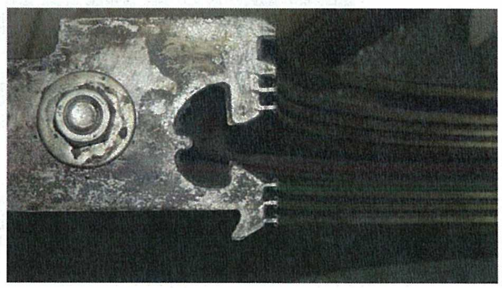
Steam Turbine:

The Steam Turbine pedestals were opened and inspected. The following is a result of the findings.

T3 Outer Oil Deflector – The T3 outer oil deflector, Upper and Lower half, is heavily rubbed and will need to be repaired or replaced. The lower oil deflector clearance is "0" and the upper oil deflector as found clearance was .171" and the as built upper clearance in 2012 was .030". This indicates .141" wear in oil deflector bore. Accurate measurements could not be taken due to smeared and rolled material.

Holyrood Unit 1 Forced Outage
Results of Phase 1 Inspection and Recommendation for Further Inspection

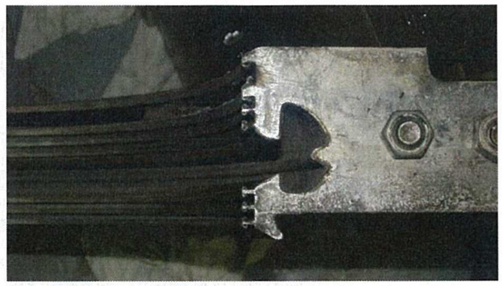
T3 Outer oil deflector prior to removal



T3 U/H outer oil deflector

T3 U/H outer oil deflector

Holyrood Unit 1 Forced Outage
Results of Phase 1 Inspection and Recommendation for Further Inspection



T3 U/H outer oil deflector

T3 L/H outer oil deflector L/S

T3 L/H outer oil deflector R/S

T3 Bearing – Bearing is wiped. There is Melted Babbitt on the top of the bearing, inside the eyebolt holes and around the bearing pads. Once the top half of the bearing was removed, the Babbitt was found to be melted down to the dovetails on the Upper half and the lower half shows melted down to the dovetails at the horizontal joint. The feeler check between the upper half and the journal prior to removal, showed .270" clearance. Assembly clearance in 2012 was .016". This indicates .254" wipe in bearing. The as found oil bore at T3 outer was L=8.637", B=8.497", R=8.606". The as assembled oil bore was L=8.621", B=8.629", R=8.628". This shows shaft low in bore .132" at outer fit. The as found oil bore at T3 inner was L=5.892", B=5.692", R=5.858". The as assembled oil bore was L=5.870", B=5.858", R=5.882". This shows the shaft low in the bore .166" at the inner oil bore.

T3 Bearing U/H prior to removal

T3 Bearing U/H L/S joint

T3 Bearing U/H R/S joint

Holyrood Unit 1 Forced Outage
Results of Phase 1 Inspection and Recommendation for Further Inspection

T3 Bearing U/H with upper bolt on seal removed – notice Babbitt

T3 Bearing U/H severe wipe down to dovetails

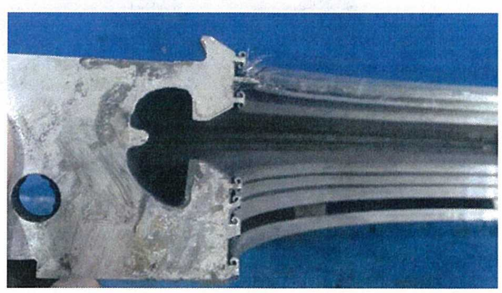
T3 Bearing and Journal L/H

Holyrood Unit 1 Forced Outage
Results of Phase 1 Inspection and Recommendation for Further Inspection

T3 Bearing and Journal L/H

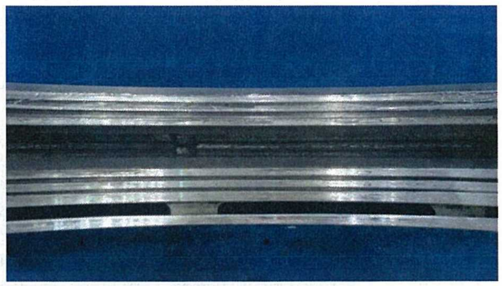
T3 Bearing and Journal as viewed from the Left side

T3 Inner Oil Deflector – The T3 Inner oil deflector, Upper and Lower, is wiped and need to be replaced. The feeler check on the upper half of the T2 inner showed .175" clearance as found, and compared to the as assembled in 2012 of .031", the clearance is opened up .144".

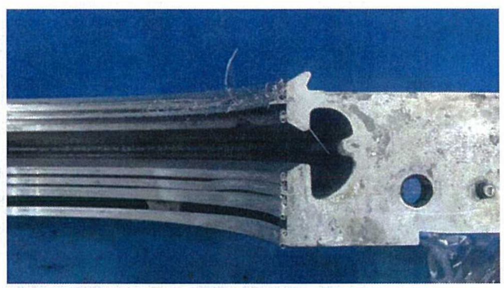


T3 Inner Oil Deflector U/H

Holyrood Unit 1 Forced Outage
Results of Phase 1 Inspection and Recommendation for Further Inspection



T3 Inner Oil Deflector U/H



T3 Inner Oil Deflector U/H

T3 Inner oil Deflector U/H

Holyrood Unit 1 Forced Outage
Results of Phase 1 Inspection and Recommendation for Further Inspection

T3 Inner Oil Deflector L/H Left side

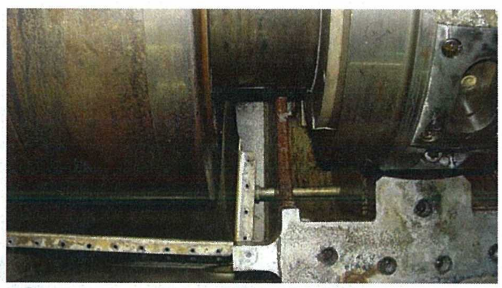
T3 Inner Oil Deflector L/H Right side

T3 Inner Oil Deflector Shaft area

Coupling Guard – the upper coupling guard was found loose and sitting on the top or the supports. The lower coupling guard was found loose and sitting in bottom of sump. The guard bolting that bolts the upper and lower together are missing and the support bolts for the U/H attachment to the support tabs in the pedestal show 2 missing and 2 broken off. The lower guard shows heavy rubbing in the bottom bore front and rear and the top guard shows minor rubbing front and rear bores at the horizontal joint.

Holyrood Unit 1 Forced Outage
Results of Phase 1 Inspection and Recommendation for Further Inspection

Lower Half coupling guard showing rub in bore



Lower Half coupling guard found lying in bottom of sump

Lower half coupling guard lying in bottom of sump and Babbitt in bottom of sump

Holyrood Unit 1 Forced Outage
Results of Phase 1 Inspection and Recommendation for Further Inspection

Lower half coupling guard with rubbing in bore

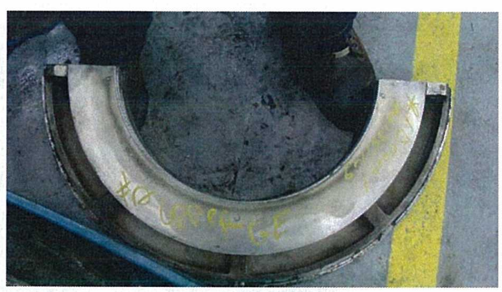
Upper half coupling guard showing rub in bore at horizontal joint area – one axial rub

Upper half coupling guard showing rub in bore at horizontal joint area – on axial rub

T2 Outer Oil Deflector (GE) – The T2 outer oil deflector, Upper and Lower half, is heavily rubbed and will need to be repaired or replaced. The lower oil deflector clearance is "0" and the upper oil deflector as found clearance was .340" and the as built upper clearance in 2012 was .032". This indicates .308" wear in oil deflector bore. Accurate measurements could not be taken due to smeared and rolled material.

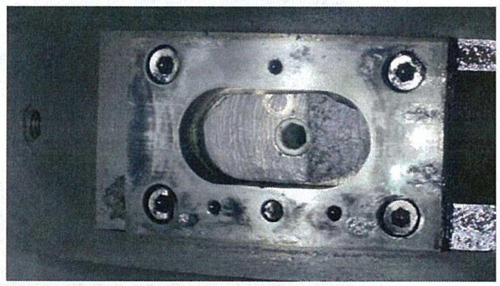
T2 Outboard Oil Deflector U/H

T2 Outboard Oil Deflector U/H



T2 Outboard Oil Deflector U/H

T2 Bearing – Bearing is wiped. There is Melted Babbitt on the top of the bearing, inside the eyebolt holes and around the bearing pads and what appears to be soot on the outside of the bearing. Once the top half of the bearing was removed, the Babbitt was found to be melted down to the dovetails on the Upper half and the lower half shows melted down to the dovetails at the horizontal joint. The feeler check between the upper half and the journal prior to removal, showed .308" clearance. Assembly clearance in 2012 was .024". This indicates .284" wipe in bearing. The as found oil bore at T2 outer was L=5.373”, B=5.148”, R=5.382”. The as assembled oil bore was L=5.372”, B=5.359”, R=5.371”. This shows shaft low in bore .211” at outer fit. The as found oil bore at T2 inner was L=5.376”, B=5.160”, R=5.382”. The as assembled oil bore was L=5.373”, B=5.359”, R=5.371”. This shows the shaft low in the bore .199” at the inner oil bore.

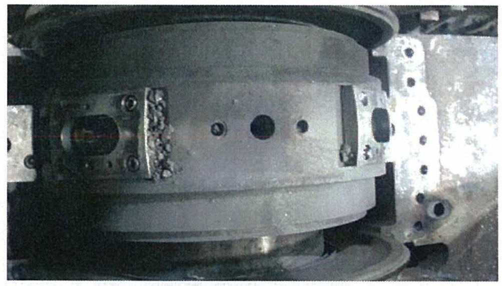


T2 U/H Bearing prior to removal

T2 U/H Bearing prior to removal

T2 U/H Bearing prior to removal

Holyrood Unit 1 Forced Outage
Results of Phase 1 Inspection and Recommendation for Further Inspection

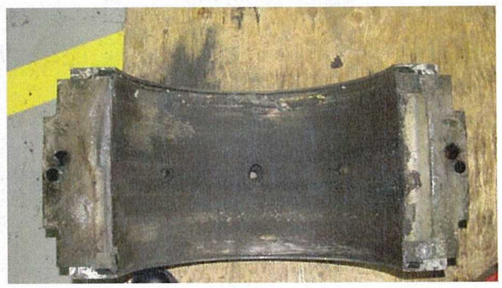


T2 U/H Bearing prior to removal

T2 U/H Bearing bore

T2 U/H Bearing Bore

Holyrood Unit 1 Forced Outage
Results of Phase 1 Inspection and Recommendation for Further Inspection



T2 U/H Bearing Bore

T2 U/H Bearing

T2 U/H Bearing

Holyrood Unit 1 Forced Outage
Results of Phase 1 Inspection and Recommendation for Further Inspection

T2 U/H Bearing

T2 U/H Bearing bore

T2 U/H Bearing Bore

Holyrood Unit 1 Forced Outage
Results of Phase 1 Inspection and Recommendation for Further Inspection

T2 L/H Bearing and Journal LS

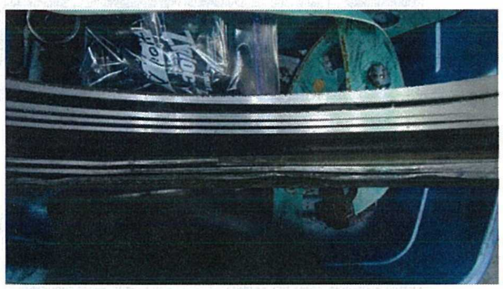
T2 L/H Bearing and Journal LS

T2 L/H Bearing and Journal RS

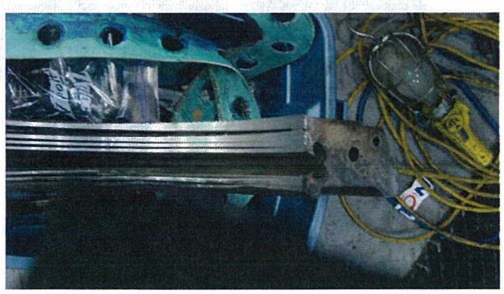
Holyrood Unit 1 Forced Outage
Results of Phase 1 Inspection and Recommendation for Further Inspection

T2 L/H Bearing and Journal RS

T2 Inner Oil Deflector (TE) – The T2 inner oil deflector, Upper and Lower half, is heavily rubbed and will need to be repaired or replaced. The lower oil deflector clearance is "0" and the upper oil deflector as found clearance was .343" and the as built upper clearance in 2012 was .030". This indicates .313" wear in oil deflector bore. Accurate measurements could not be taken due to smeared and rolled material.

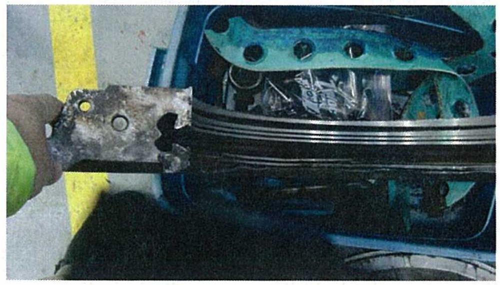


T2 U/H Inner Oil Deflector



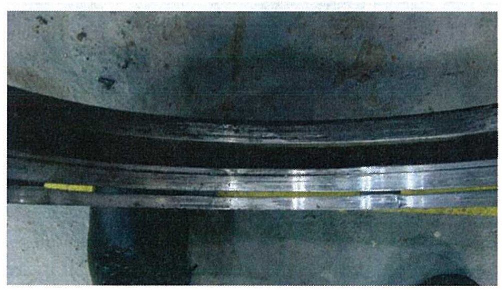
T2 U/H Inner Oil Deflector

Holyrood Unit 1 Forced Outage
Results of Phase 1 Inspection and Recommendation for Further Inspection



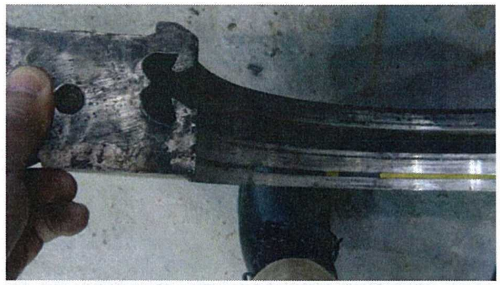
T2 U/H Inner Oil Deflector

T2 U/H Inner Oil Deflector



T2 L/H Inner Oil Deflector

Holyrood Unit 1 Forced Outage
Results of Phase 1 Inspection and Recommendation for Further Inspection



T2 L/H Inner Oil Deflector

T2 L/H Inner Oil Deflector

T2 L/H Inner Oil Deflector

N1 Upper Packing Gland – the upper packing gland was removed to allow removal of the Front standard cover. Upon removal, the R1 ring of packing fell out as the springs were severely damaged from the fire at the front end of the unit. The packing is severely damaged from rubbing as is R2 packing upper half. The Lower half R1 and R2 packing are also severely damaged. Once the gland was removed, you can see that the inner gland, containing R3 and R4 packing, appears to have separated as there is clearance between the upper and lower joints.

N1 Gland Casing U/H

R1 Packing Ring

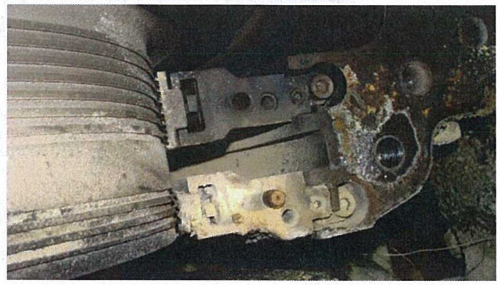
R1 Packing Ring - damaged

Holyrood Unit 1 Forced Outage
Results of Phase 1 Inspection and Recommendation for Further Inspection

R1 Packing Ring Damage

R1 packing ring

N1 Packing Gland L/H Left Side



N1 Packing Gland L/H Right Side

T1 Outer Oil Deflector (GE) – The T1 outer oil deflector, Upper and Lower half, is heavily rubbed and will need to be repaired or replaced. The lower oil deflector clearance is "0" and the upper oil deflector as found clearance was .343" and the as built upper clearance in 2012 was .020". This indicates .323" wear in oil deflector bore. Accurate measurements could not be taken due to smeared and rolled material.

T1 Upper Oil Deflector

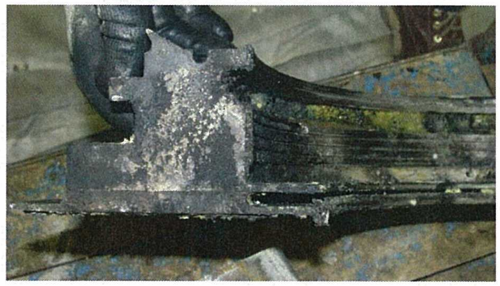
T1 Upper Oil Deflector

Holyrood Unit 1 Forced Outage
Results of Phase 1 Inspection and Recommendation for Further Inspection

T1 Upper Oil Deflector

T1 Upper Oil Deflector

T1 Lower Oil Deflector



T1 Lower Oil Deflector

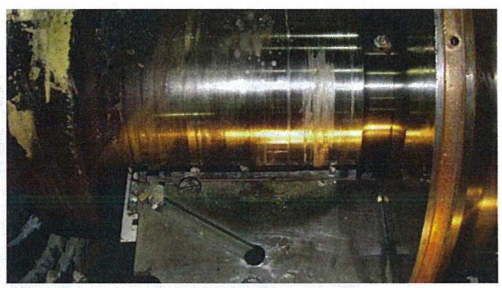
T1 Lower Oil Deflector

T1 Lower Oil Deflector

T1 Bearing – Bearing is wiped. Once the top half of the bearing was removed, the Babbitt was found to be heavily wiped in the upper and lower half. The feeler check between the upper half and the journal prior to removal could not be performed due to space limitations. The as found oil bore at T1 outer was L=2.274", B=2.105", R=2.357". The as assembled oil bore was L=2.295", B=2.251", R=2.327". This shows shaft low in bore .146" at outer fit.

Holyrood Unit 1 Forced Outage
Results of Phase 1 Inspection and Recommendation for Further Inspection

T1 U/H Bearing



T1 L/H Bearing and Journal Left side

T1 L/H Bearing and Journal Right side

Holyrood Unit 1 Forced Outage
Results of Phase 1 Inspection and Recommendation for Further Inspection

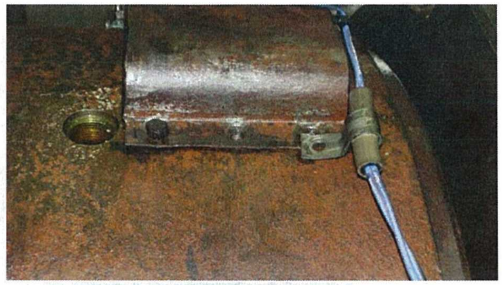
T1 Bearing and Thrust Right side

T1 Bearing and Thrust Left side

T1 U/H Bearing

Thrust Bearing – The thrust bearing Active Plate is heavily damaged as the thrust runner is embedded in the Copper back of the thrust plate. A Feeler check of the thrust shows the Rotor .140" plus downstream. This measurement taken between the Inactive thrust plate and the Inactive thrust shim. An accurate measurement of just how far downstream the rotor is cannot be taken at this time. The Inactive thrust plate still has the Babbitt on the plate and the profile and can be moved radially.

Holyrood Unit 1 Forced Outage
Results of Phase 1 Inspection and Recommendation for Further Inspection



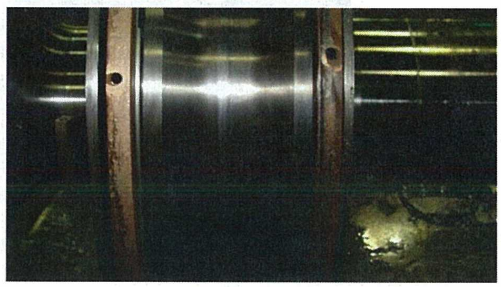
Thrust Bearing Flow Diverter

Thrust Bearing Flow Diverter

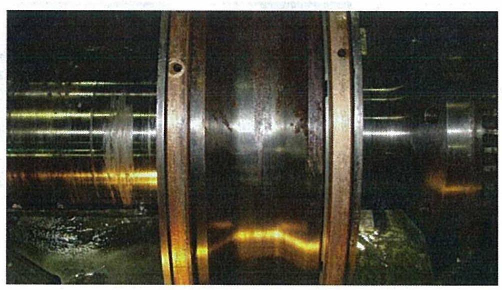
Thrust Bearing U/H Cage Oil Seal

Holyrood Unit 1 Forced Outage
Results of Phase 1 Inspection and Recommendation for Further Inspection

Thrust Bearing U/H Cage Oil Seal



Thrust Right Side



Thrust Left side

Holyrood Unit 1 Forced Outage
Results of Phase 1 Inspection and Recommendation for Further Inspection

Thrust cage oil seal L/H Left side

Thrust Cage oil seal L/H right side

Thrust Bearing oil seal ring – rolled up and broken retainer screw

Holyrood Unit 1 Forced Outage
Results of Phase 1 Inspection and Recommendation for Further Inspection

Thrust Cover U/H Rolled Oil Seal ring and broken screw

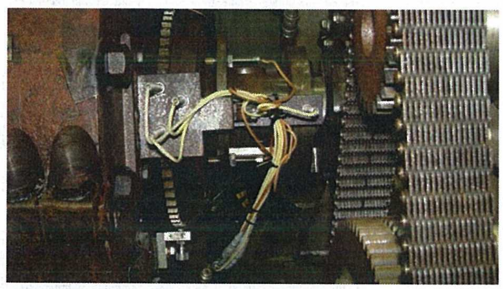
Babbitt in Front Standard below Thrust Cage

Thrust Active Side – Thrust Runner Rubbed into Thrust Plate

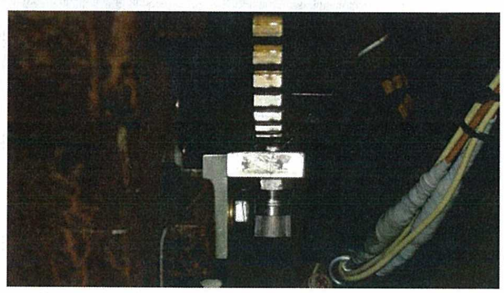
Holyrood Unit 1 Forced Outage
Results of Phase 1 Inspection and Recommendation for Further Inspection

Thrust Active side – Thrust Runner Rubbed into Thrust Plate

Speed Probes and FS Instrumentation – There are 4 speed probes that have become disconnected and the lower probes have rubbed hard on the 60 tooth wheel and damaged the wheel. The lower probes are no longer useable. The upper probes need to be checked out by I&C to verify if they still work.



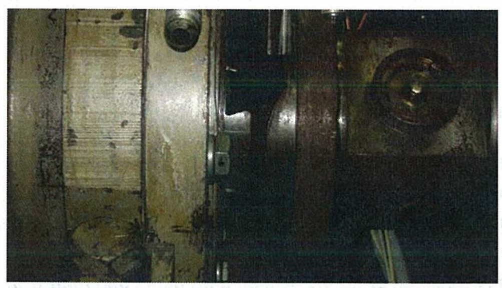
Speed probes and Instrumentation LS



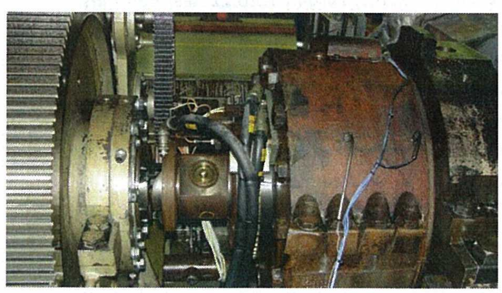
60 Tooth Wheel and Probe Damage

Thrust RS and Instrumentation

Turning Gear – the Jaw clutch on the turbine rotor is below the jaw clutch on the Turning gear, thus the clutch cannot engage. Other than this, the Turning Gear appears to be in good condition.

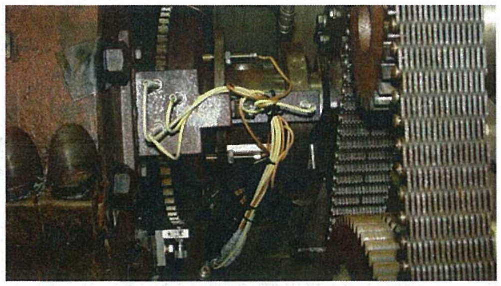


Turning Gear Clutch



Turning Gear and Clutch

Holyrood Unit 1 Forced Outage
Results of Phase 1 Inspection and Recommendation for Further Inspection



Turning Gear and Clutch

Vibration Probes – the vibration probes on bearing T1 through T3 are damaged and must be replaced. T4 and T5 appear not to have been damaged in the incident. These should be evaluated by Customer and Bentley Nevada possibly returning to service.

Results and Recommendations for further inspection and repairs:

1. ***Disassemble Generator – complete disassembly of Generator for inspection of all components, including cleanliness of oil piping.***
2. ***Generator Electrical Testing – full set of tests on the Stator and the Generator rotor by qualified Generator specialist.***
3. ***Disassembly and inspection of the H2 seal oil unit, filters and float trap.***
4. ***Complete disassembly of the HP/IP/LP Turbine to include the removal of the upper and lower diaphragms, packing segments, Turbine rotor, Lower Bearings.***
5. ***Inspection of the GE Full Flow filtration system.***
6. ***Clean and visual inspect L.O. Tank***
7. ***Retrieve spare bearings from Customers stock, inspect and measure.***
8. ***Retrieve spare oil deflectors from customer stock, inspect and measure***
9. ***Blast Clean and NDE of Turbine Rotor, Diaphragms, Bearing fits and Bearings.***
10. ***Drop check on diaphragms to determine dishing.***
11. ***Lathe checks of Turbine rotor for runouts – axial and radial.***
12. ***Lathe checks of Generator rotor for runouts – axial and radial.***
13. ***Remove Lube oil Pumps and inspect wet ends of pumps***
14. ***Remove L.O. Coolers for inspection and testing***
15. ***Remove Hydrogen coolers for inspection and testing***
16. ***The position of the Turbine Rotor as found will most likely result in Axial rubbing in the HP Section of the Turbine as a minimum. The severity of the rubs would be speculative at this point, however, the Axial clearances in the HP section with the rotor against the Active thrust***

face (rear pad) range from .152" to .098". This could result in not just bucket cover rubbing to the diaphragms, but blade contact with the diaphragms.

17. *The Radial position of the Turbine Rotor in the Bearing Bores (T1 low .146", T2 low .211", T3 low .166") will most likely result in severe Radial rubbing (shaft to gland and diaphragm packing, bucket covers to radial spill strips, bucket covers to diaphragms). This could result in radial cover damage and/or loss of bucket cover in extreme situations.*
18. *T1 Oil Deflector – wiped. Need to replace*
19. *T1 Bearing – Wiped. Need to replace liner as a minimum*
20. *Thrust Bearing*
    a. *Active Plate – wiped. Replace*
    b. *Thrust Runner on Rotor – Damaged on Active side as minimum. Machine to remove scoring and hot spots.*
    c. *Inactive Plate – moderate damage. Replace*
    d. *Casing oil Seal – Damaged. Replace*
    e. *Casing Bronze seal – Damaged. Replace*
21. *60 tooth wheel – Damaged. Replace or repair.*
22. *Speed Probes – Damaged. Replace*
23. *N1 packing Gland – R1 and R2 packing segments are severely damaged. Replace with new packing rings, springs and retainers*
24. *T2 Inboard oil deflector – Wiped. Replace*
25. *T2 Bearing – Wiped. Replace*
26. *T2 outer oil deflector – Wiped. Replace*
27. *T3 Inboard oil deflector – wiped. Replace*
28. *T3 Bearing – wiped. Replace*
29. *T3 Outer oil deflector – Wiped. Replace*
30. *Coupling cover – shaft bores rubbed, clean up and return to service. Repair bolting as required.*
31. *Replace all Diaphragm Packing, springs and retainers in the HP/IP and LP Sections*
32. *Replace all diaphragm radial spill strips in HP/IP and LP*
33. *T4 Outer Oil Deflector – wiped. Repair*
34. *T4 Bearing – wiped. Repair or replace*
35. *TE H2 Seal Casing – Casing should be sent out for inspection and repairs. It was recommended in 2012 to send out at the next inspection for truing and re-machining of the hook fits, true vertical and horizontal joints, fit new H2 Seal rings and blue.*
36. *TE H2 Seals – Seals should be replaced. Recommend H2 seals be fitted and blued to the H2 seal casing following casing inspection and repairs. See above #32.*
37. *TE H2 Seal Casing gas side oil deflector – the deflector is rubbed hard and should be replaced. This should be done in conjunction with items 32, 33 above.*
38. *T4 Inner oil deflector – hard rub. Repair or replace.*
39. *T5 Inner oil deflector – hard rub. Repair or replace.*

Holyrood Unit 1 Forced Outage
Results of Phase 1 Inspection and Recommendation for Further Inspection

40. ***CE H2 Seal Casing gas side oil deflector – the deflector is rubbed hard and should be replaced. This should be done in conjunction with items 38, 39 below.***
41. ***CE H2 Seals – Seals should be replaced. Recommend H2 seals be fitted and blued to the H2 seal casing following casing inspection and repairs. See #39.***
42. ***CE H2 Seal Casing - Casing should be sent out for inspection and repairs. It was recommended in 2012 to send out at the next inspection for truing and re-machining of the hook fits, true vertical and horizontal joints, fit new H2 Seal rings and blue.***
43. ***T5 Bearing – wiped. Repair or replace.***
44. ***T5 outer oil deflector – wiped. Repair or replace.***
45. ***Recommend High volume oil flush be completed before starting reassembly of the unit.***

FIELD SERVICE REPORT (FSR) 030213	Page 1 of 123 Total 123 pages
Month Day Year **Date : 03 / 02 / 2013**	**Plant: Holyrood**
Reporter: James George **Dept : LSN NAM TG 4071**	**Customer: Newfoundland and Labrador Hydro**
FSR received by Customer: Position : Plant Engineer Name : Todd Collins Sign : Date :	**Subject:** Holyrood Steam Turbine/Gen **Type : Disassembly/Inspection**
Erection ☐ Repair ☑ Overhaul ☐ Start up ☐ Investigation ☑ Balance ☐	Our Order No.: 4100296208 Serial #: **0940310** Additional Name-plate data:
Representative Order No.: IE0-000416 Customer Order No.: 4100296208	**Rating :** **Turbine Type : GE D3** **Generator Code:** **Manufacturer: GE**

1. SUMMARY:

The following is a summary of the work performed by Alstom Power during the Disassembly and Inspection Phase (Phase 2) of the Forced Outage on Unit 1, GE Turbine S/N 940310, located at the NALCOR Energy Holyrood Station, Holyrood, NL. This report outlines the work performed in each section of the unit and the findings in each section.

Prior to Alstom's commencement of work on February 4, 2013, the following work was completed:

- LOTO and all necessary permits
- Generator disassembled – complete (H2 coolers not removed at this time)
- All bearing standards open and all components removed with the exception of lower bearings.
- Main lube oil tank drained

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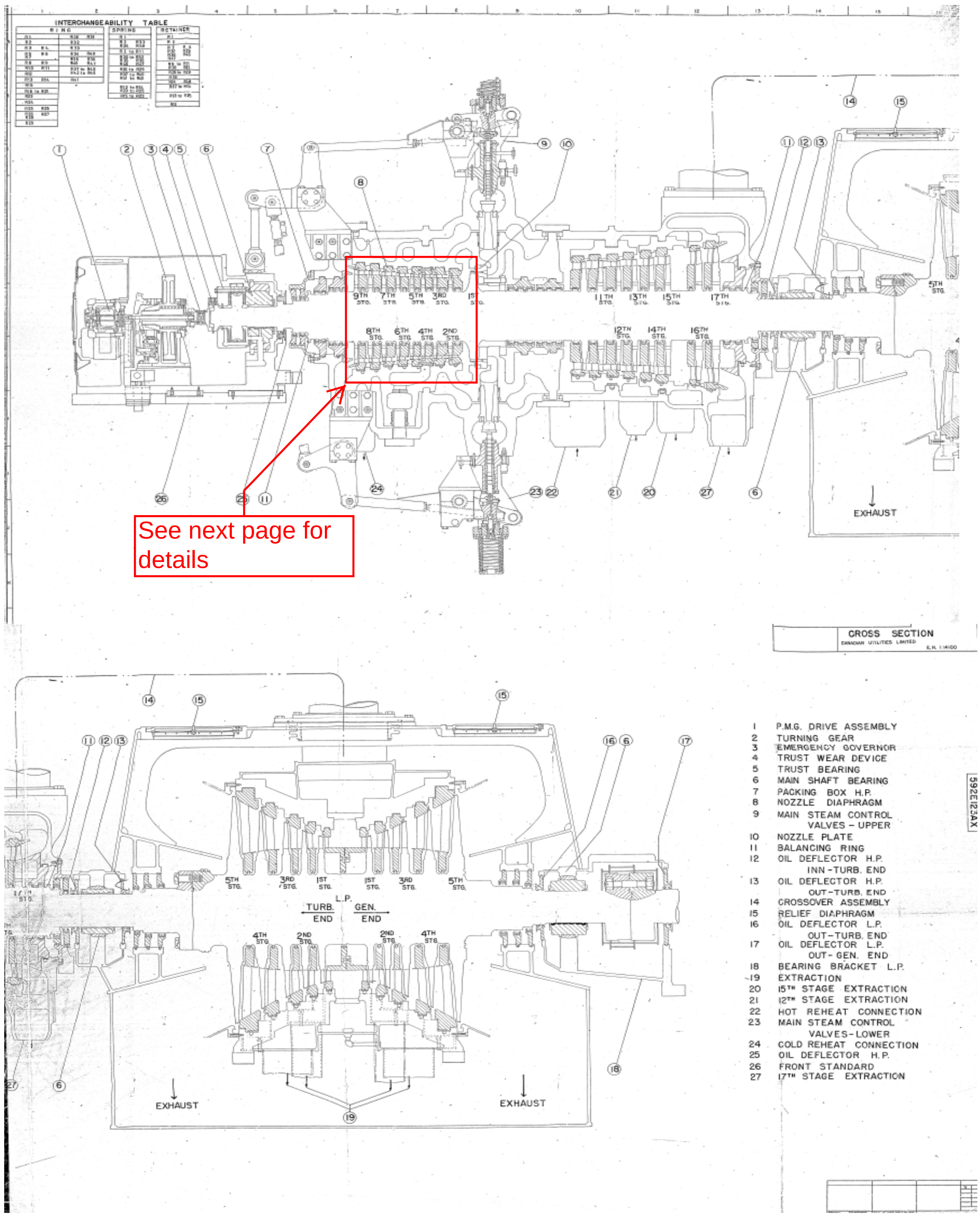
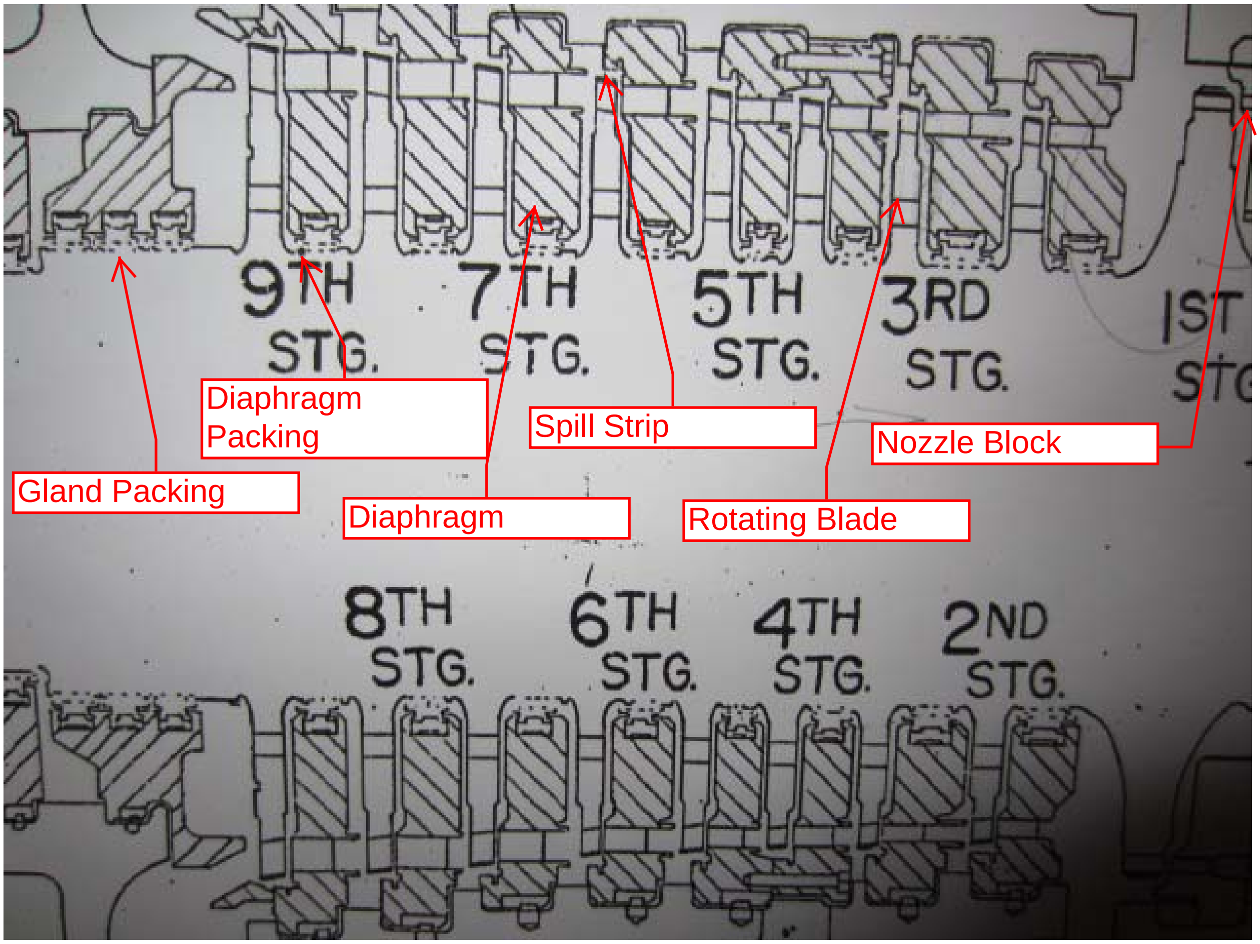

INTERCHANGEABILITY TABLE
See next page for details
EXHAUST
CROSS SECTION
CANADIAN UTILITIES LIMITED
TURB. END
GEN. END
L.P.
EXHAUST
EXHAUST
592E123AX
1 P.M.G. DRIVE ASSEMBLY
2 TURNING GEAR
3 EMERGENCY GOVERNOR
4 TRUST WEAR DEVICE
5 TRUST BEARING
6 MAIN SHAFT BEARING
7 PACKING BOX H.P.
8 NOZZLE DIAPHRAGM
9 MAIN STEAM CONTROL VALVES – UPPER
10 NOZZLE PLATE
11 BALANCING RING
12 OIL DEFLECTOR H.P. INN-TURB. END
13 OIL DEFLECTOR H.P. OUT-TURB. END
14 CROSSOVER ASSEMBLY
15 RELIEF DIAPHRAGM
16 OIL DEFLECTOR L.P. OUT-TURB. END
17 OIL DEFLECTOR L.P. OUT-GEN. END
18 BEARING BRACKET L.P.
19 EXTRACTION
20 15TH STAGE EXTRACTION
21 12TH STAGE EXTRACTION
22 HOT REHEAT CONNECTION
23 MAIN STEAM CONTROL VALVES-LOWER
24 COLD REHEAT CONNECTION
25 OIL DEFLECTOR H.P.
26 FRONT STANDARD
27 17TH STAGE EXTRACTION



CrossOvers:

Scaffold was erected to the crossovers by the Alstom contractor and the Plant I&C removed all instrumentation associated with the crossover. Alstom unbolted and removed the crossovers to the laydown area and secured.

All bolting on the crossover flanges were found to be tight and in good condition.

HP/IP Outer Shell:

The outer shell bolting and main steam inlet bolting was checked at disassembly to verify the bolting was still tight and not damaged during the incident. All outer shell bolting on the HP/IP shell was found to be tight and no visual signs of damage. UT of studs was performed, and no indications were found.

The main steam lead bolting was found to be loose and bolting could be loosened by hand. There were no signs of "steam leakage" at the flange during the disassembly. These bolts were "stretched" during installation in 2012.

HP/IP Upper Half Inner Cylinder:

The HP Inner cylinder was unbolted for removal. During the disassembly, there were 3 joint bolts on the left side (numbers 95. 101. 103) and 1 joint bolt on the right side (number 95) that did not require heating to remove. The nuts were still on the as assembled rotation mark. These bolts are located around the inlet section of the steam chest.

A visual inspection of the horizontal joint bolting did not reveal any signs of damage to any of the studs, nuts or washers.

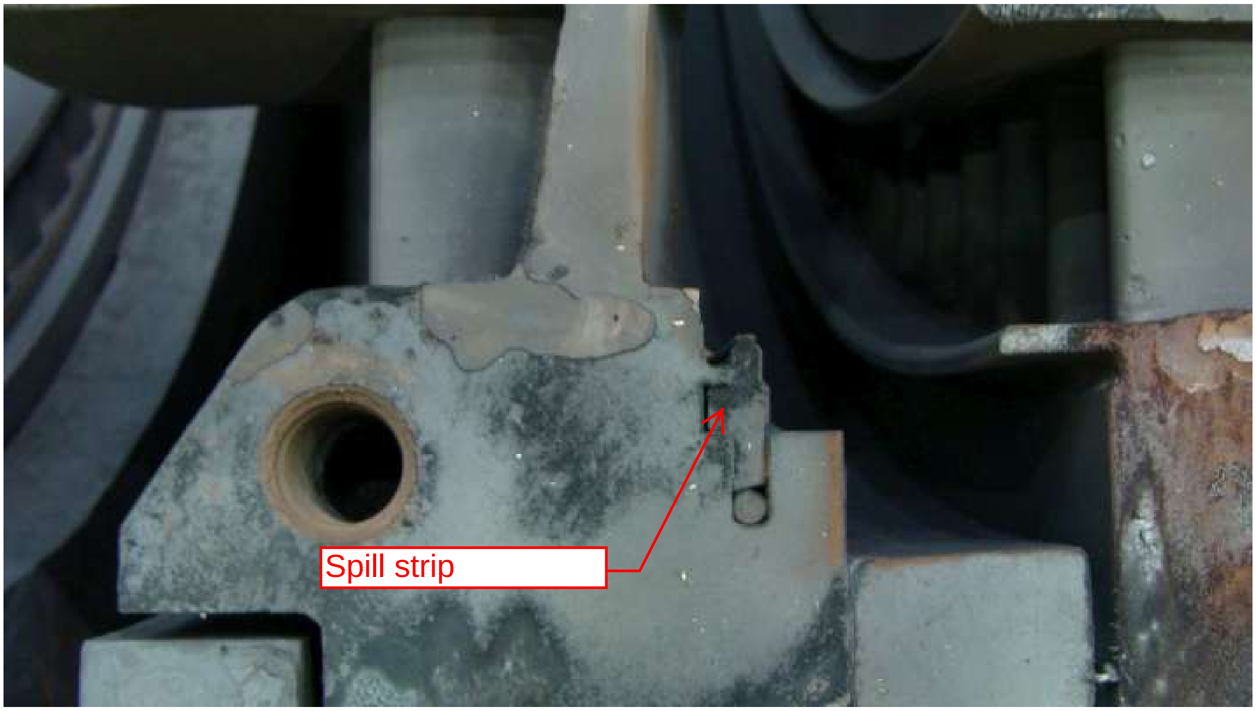
The HP upper inner shell was flipped in the laydown area and set level to allow inspection of the upper diaphragms and removal of same. The following is the results of the visual inspection of each stage with upper half diaphragms installed:

- N2 packing gland
    - Gland packing segments – rows 16 thru 21 shows moderate rubbing. Packing tooth profiles are still good.
- First stage nozzle upper half
    - No signs of axial rubbing on the first stage nozzle.
    - No signs of partition damage.
    - Evidence of heavy radial rubbing at the integral spill strip.
    - No signs of axial separation of the nozzle from the shell fit.
    - All bolting in place and no signs of movement.
- Stage 2 Diaphragm
    - No sign of rubbing between diaphragm inner web and the 2nd stage wheel
    - Hard Axial rub at the outer setback face (caused by contact with bucket cover) and the inner setback face (caused by contact with bucket root appendage)
    - No signs of partition damage as viewed from the horizontal joint
    - Radial spill strip is hard rubbed radial and axial
- Stage 3 Diaphragm
    - No sign of rubbing between diaphragm inner web and the 3rd stage wheel
    - Hard Axial rub at the outer setback face (caused by contact with bucket cover) and the inner setback face (caused by contact with bucket root appendage)
    - No signs of partition damage as viewed from the horizontal joint
    - Radial spill strip is hard rubbed radial and axial
- Stage 4 Diaphragm

- No sign of rubbing between diaphragm inner web and the 4th stage wheel
- Hard Axial rub at the outer setback face (caused by contact with bucket cover) and the inner setback face (caused by contact with bucket root appendage)
- No signs of partition damage as viewed from the horizontal joint
- Radial spill strip is hard rubbed radial and axial

- Stage 5 Diaphragm
  - No sign of rubbing between diaphragm inner web and the 5th stage wheel
  - Hard Axial rub at the outer setback face (caused by contact with bucket cover) and the inner setback face (caused by contact with bucket root appendage)
  - No signs of partition damage as viewed from the horizontal joint
  - Radial spill strip is hard rubbed radial and axial
- Stage 6 Diaphragm
  - No sign of rubbing between diaphragm inner web and the 6th stage wheel
  - Hard Axial rub at the outer setback face (caused by contact with bucket cover) and the inner setback face (caused by contact with bucket root appendage)
  - No signs of partition damage as viewed from the horizontal joint
  - Radial spill strip is hard rubbed radial and axial
- Stage 7 Diaphragm
  - No sign of rubbing between diaphragm inner web and the 7th stage wheel
  - Hard Axial rub at the outer setback face (caused by contact with bucket cover) and the inner setback face (caused by contact with bucket root appendage)
  - No signs of partition damage as viewed from the horizontal joint
  - Radial spill strip is hard rubbed radial and axial
- Stage 8 Diaphragm
  - No sign of rubbing between diaphragm inner web and the 8th stage wheel
  - Hard Axial rub at the outer setback face (caused by contact with bucket cover).
  - No signs of partition damage as viewed from the horizontal joint
  - Radial spill strip is hard rubbed radial and axial
  - No sign of axial rubbing at the inner web
- Stage 9 Diaphragm
  - No sign of rubbing between diaphragm inner web and the 9th stage wheel
  - Hard Axial rub at the outer setback face (caused by contact with bucket cover) and the inner setback face (caused by contact with bucket root appendage)
  - No signs of partition damage as viewed from the horizontal joint
  - Radial spill strip is hard rubbed radial and axial

- Row 2 diaphragm U/H



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- Row 3 diaphragm U/H

- Row 4 diaphragm U/H

-

- Row 5 diaphragm U/H

- Row 6 diaphragm U/H

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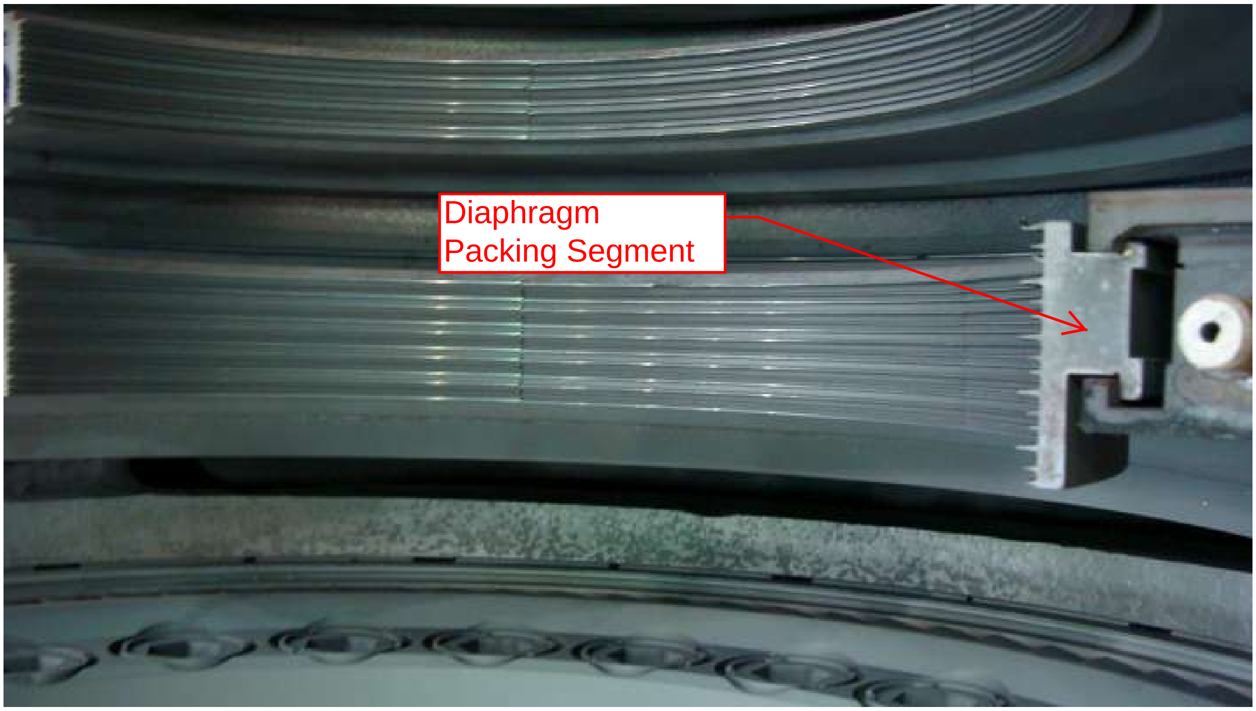
- Row 7 diaphragm U/H

- Row 8 diaphragm U/H

-

- Row 9 diaphragm U/H

- Row 2 U/H packing



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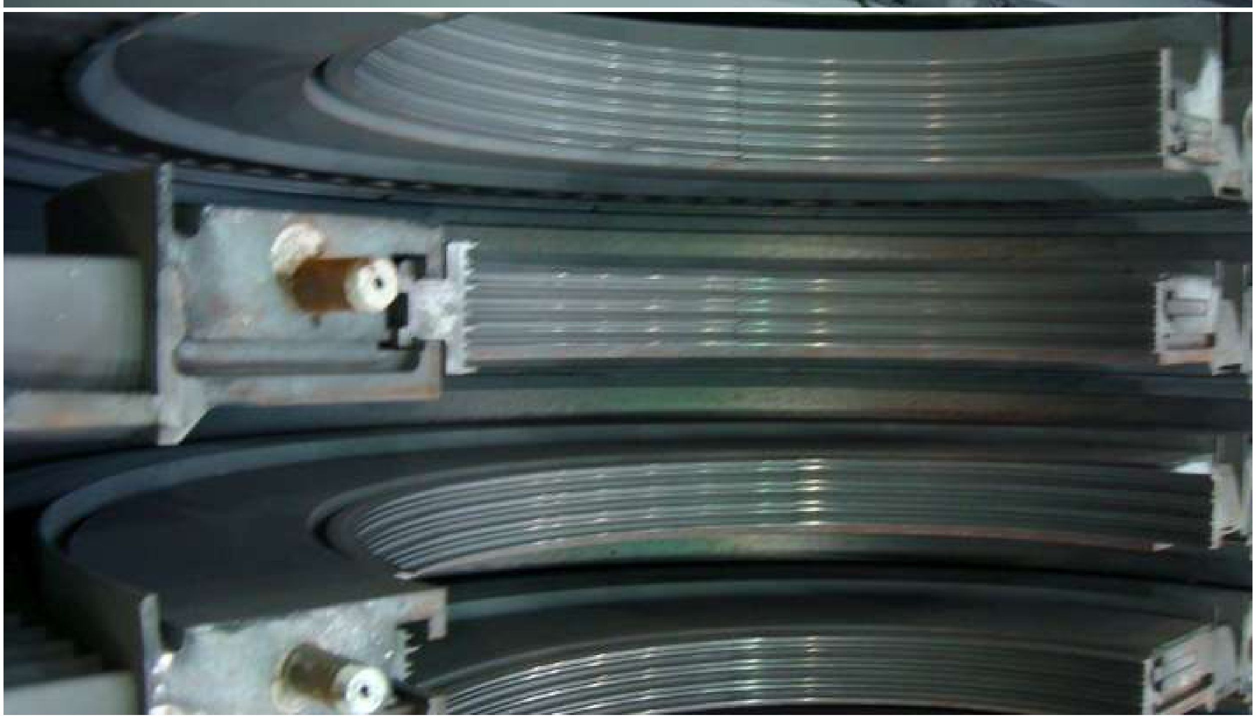
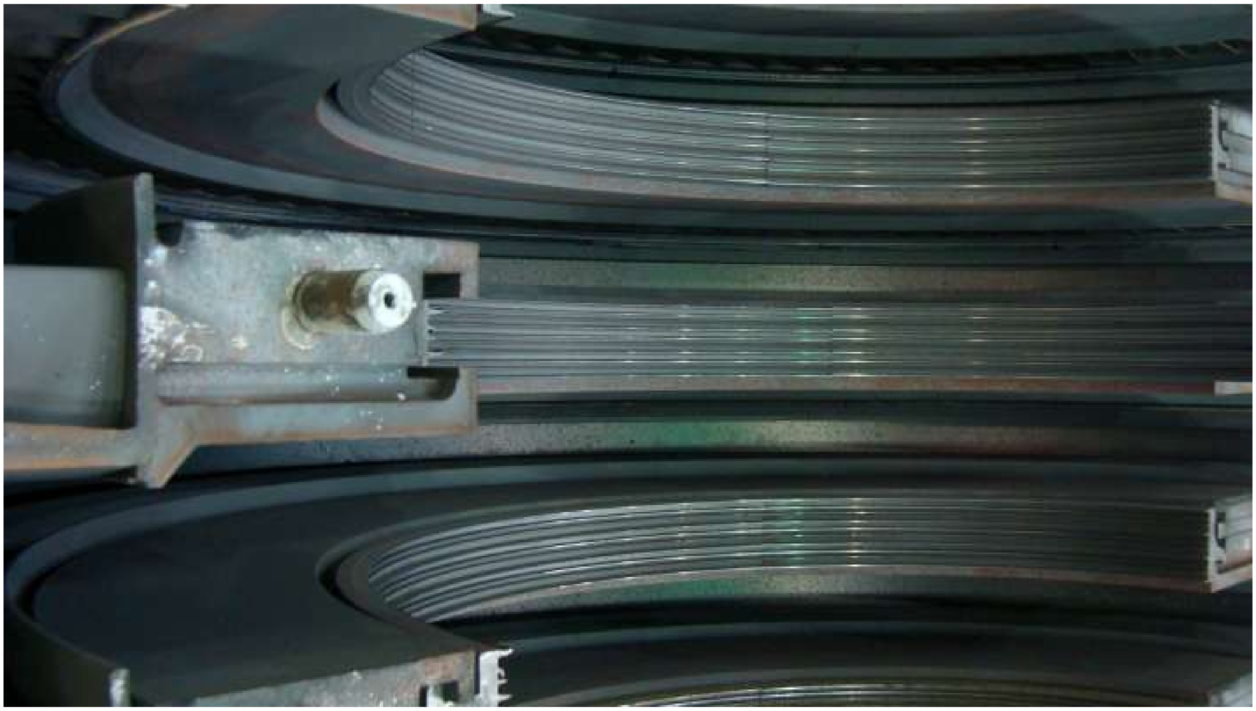


- Row 3 U/H packing

- Row 4 U/H packing



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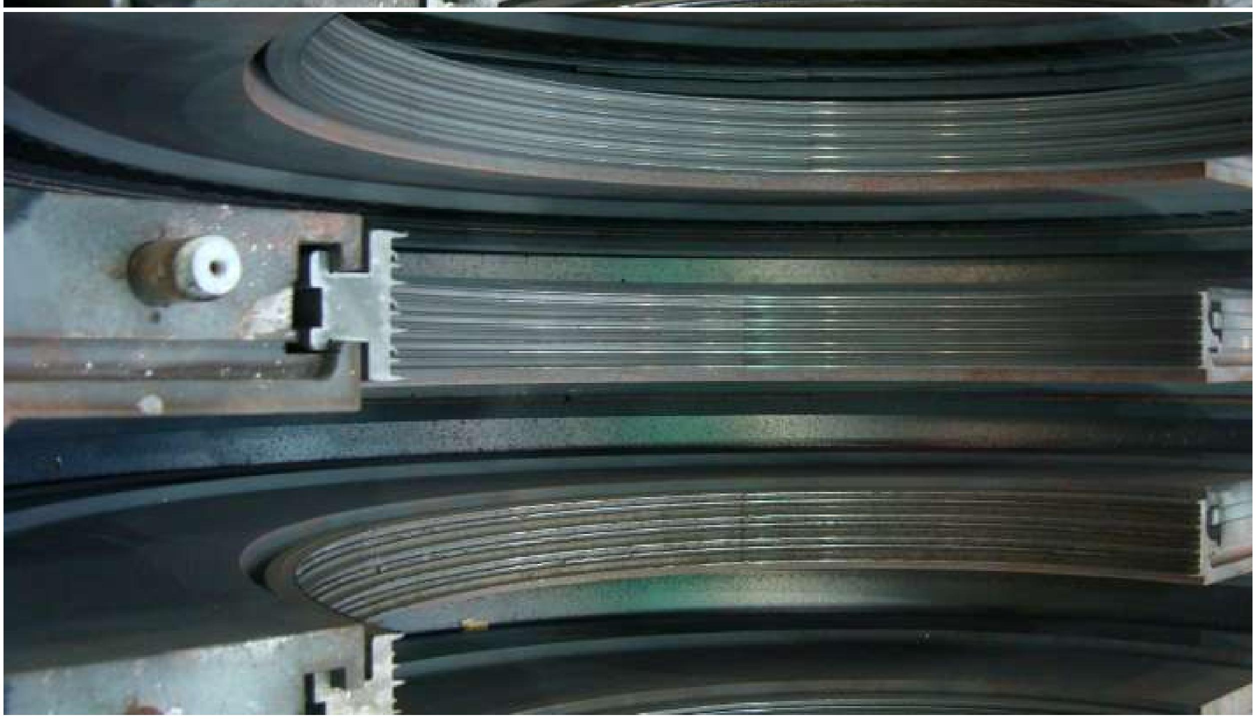
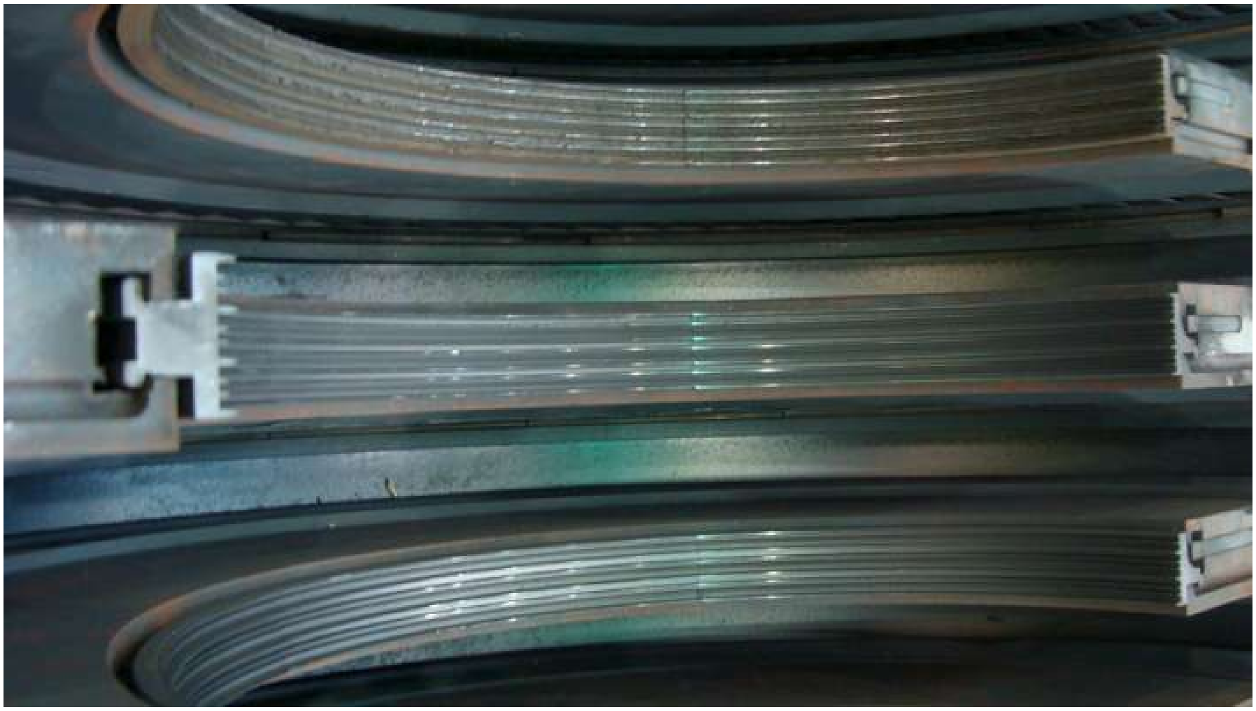


- Row 5 U/H packing

- Row 6 U/H packing



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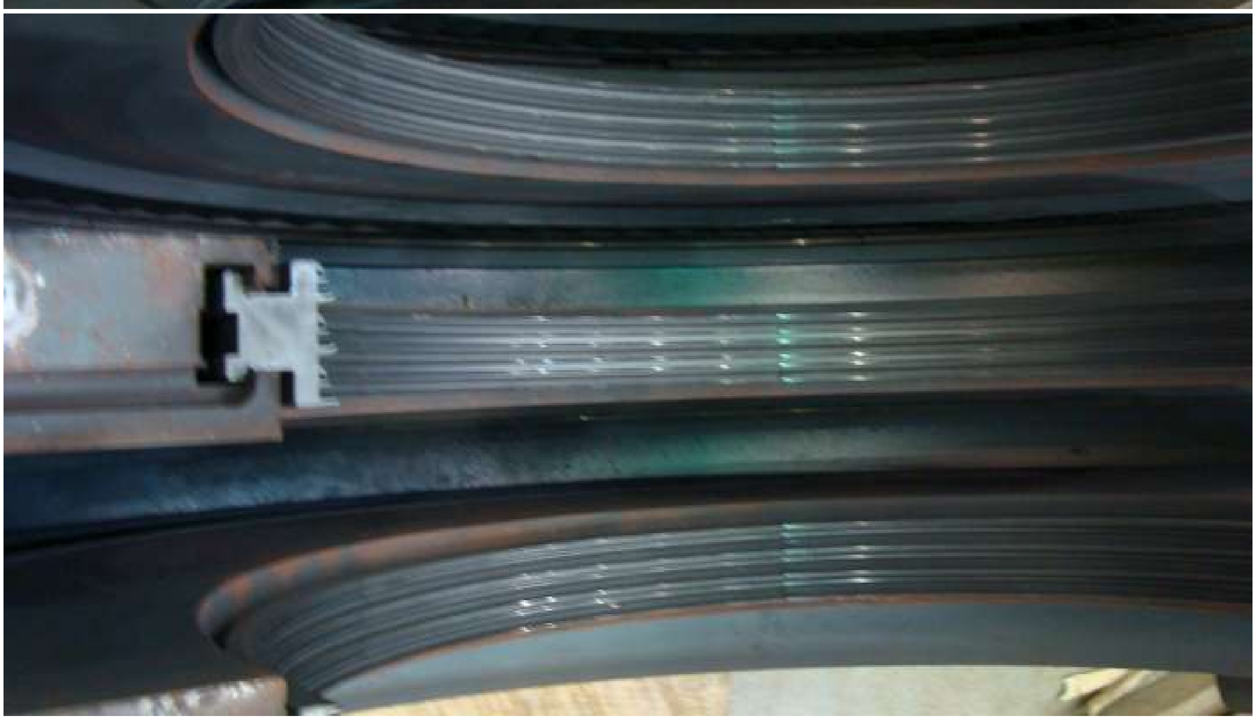


- Row 8, 9 U/H packing

IP Inner cylinders A and B:

The IP inner cylinders were unbolted for removal. During the disassembly, the horizontal joint bolting was checked for tightness. All bolting for both cylinders were found to be staked, however, the bolts were not fully torqued and could be removed without difficulty.

- Stage 11
  - No sign of axial rubbing at the inner or outer web
  - Evidence of radial rubbing at the radial spill strip
  - Diaphragm packing is rubbed – moderate.
  - No sign of partition damage
- Stage 12
  - No sign of axial rubbing at the inner or outer web
  - Evidence of radial rubbing at the radial spill strip
  - Diaphragm packing is rubbed – moderate.
  - No sign of partition damage
- Stage 13
  - No sign of axial rubbing at the inner or outer web
  - Evidence of radial rubbing at the radial spill strip
  - Diaphragm packing is rubbed – moderate.
  - No sign of partition damage
- Stage 14
  - No sign of axial rubbing at the inner or outer web
  - Evidence of radial rubbing at the radial spill strip
  - Diaphragm packing is rubbed – moderate.
  - No sign of partition damage
- Stage 15
  - No sign of axial rubbing at the inner or outer web
  - Evidence of radial rubbing at the radial spill strip
  - Diaphragm packing is rubbed – moderate.
  - No sign of partition damage
- Stage 17
  - No sign of axial rubbing at the inner or outer web
  - Evidence of radial rubbing at the radial spill strip
  - Diaphragm packing is rubbed – moderate.
  - No sign of partition damage

LP Outer Hood:

The LP outer hood was unbolted for removal. During the disassembly, a number of horizontal joint bolts were found to be only hand tight. All bolting for the outer hood and the upper gib keys

TE and GE, were removed. The hood was jacked up to break the seal, rigged and removed to the laydown area.

A visual inspection of the L-0 blades, TE and GE, was completed and there was no evidence of blade damage or rubbing.

A visual inspection of the all the struts was completed and no problems or adverse conditions were found.

The rupture diaphragms were leak checked with water. No leaks found.

Safeway was called to deck out the lower half to allow working on the LP inner cylinder.

LP Inner Cylinder:

The LP U/H inner cylinder was unbolted for removal. All bolting was found to be tight prior to removing. The inner cylinder was jacked up to break the separate the joint, rigged and removed. As a precaution prior to moving the cylinder to the laydown area, a strap was run through the bore and tensioned to prevent the possibility of the upper diaphragms from falling out, as they are upper supported diaphragms.

The inner cylinder upper half was flipped in the laydown area and blocked. Scaffold was erected to both sides of the LP Inner cylinder to allow access to the support screws and for diaphragm removal.

A visual inspection of the upper half diaphragms did not reveal any “axial” rubbing with the turbine rotor. There is evidence of radial rubs at all radial spill strips and in the diaphragm packing. There is an estimated 20-30% rubbing in the upper half packing. Once all packing is removed and better estimate on the amount of rubbing can be determined by measurement. The radial spill strips are rubbed and rolled over.

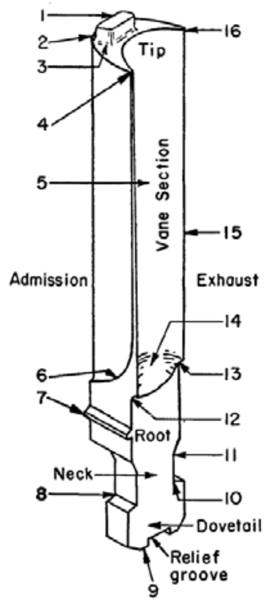
- Stage 5 TE
    - No sign of axial rubbing at the inner or outer web
    - Evidence of radial rubbing at the radial spill strip
    - Diaphragm packing is rubbed – moderate to heavy.
- Stage 4 TE
    - No sign of axial rubbing at the inner or outer web
    - Evidence of radial rubbing at the radial spill strip
    - Diaphragm packing is rubbed – moderate to heavy.

- Stage 3 TE
  - No sign of axial rubbing at the inner or outer web
  - Evidence of radial rubbing at the radial spill strip
  - Diaphragm packing is rubbed – moderate to heavy.
- Stage 2 TE
  - No sign of axial rubbing at the inner or outer web
  - Evidence of radial rubbing at the radial spill strip
  - Diaphragm packing is rubbed – moderate to heavy.
- Stage 1 TE
  - No sign of axial rubbing at the inner or outer web
  - Evidence of radial rubbing at the radial spill strip
  - Diaphragm packing is rubbed – moderate to heavy.
- Stage 1 GE
  - No sign of axial rubbing at the inner or outer web
  - Evidence of radial rubbing at the radial spill strip
  - Diaphragm packing is rubbed – moderate to heavy.
- Stage 2 GE
  - No sign of axial rubbing at the inner or outer web
  - Evidence of radial rubbing at the radial spill strip
  - Diaphragm packing is rubbed – Light to Moderate.
- Stage 3 GE
  - No sign of axial rubbing at the inner or outer web
  - Evidence of radial rubbing at the radial spill strip
  - Diaphragm packing is rubbed – Light to moderate.
- Stage 4 GE
  - No sign of axial rubbing at the inner or outer web
  - Evidence of radial rubbing at the radial spill strip
  - Diaphragm packing is rubbed – Light to moderate.
- Stage 5 GE
  - No sign of axial rubbing at the inner or outer web
  - Evidence of radial rubbing at the radial spill strip
  - Diaphragm packing is rubbed – Light to moderate.

Survey of Unit with Rotor installed and all Upper Half components removed

HP Section (stage 1 through stage 9):

The following is the results of the visual inspection of the HP section:



1. Tenon
2. Back of bucket at tip
3. Fillet at base of tenon
4. Edge—admission side at tip
5. Vane section—(that portion between tip and root)
6. Root—back fillet
7. Outer axial steam deflector
8. Base of neck—admission
9. Base of dovetail
10. Base of neck—exhaust
11. Top of neck—exhaust
12. Root fillet in admission edge overhang
13. Root fillet in exhaust edge overhang
14. Root fillet of inside radius
15. Edge—exhaust side
16. Edge—exhaust at tip

Fig. 4. Typical bucket—tangential dovetail with integral hooks (inside or inverted-hook type)

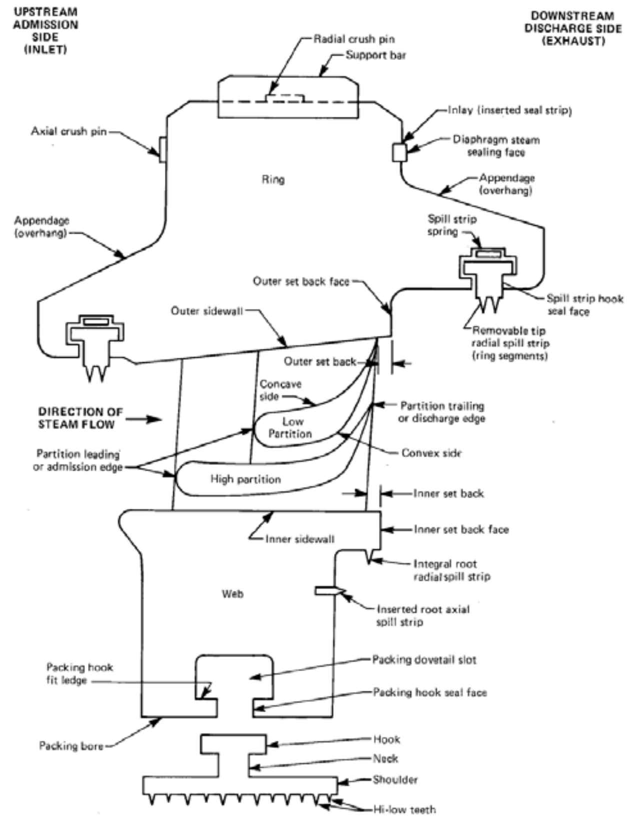


Fig. 2. Typical single-flow modern diaphragm geometry, with high-low partitions and removable radial spill strips.

- N2 packing gland
  - Turbine Rotor – shows moderate radial packing rubs at all lands.
  - Gland packing segments – rows 16 thru 21 shows moderate rubbing. Packing tooth profiles are still good.
- First Stage Nozzle
  - The face of the nozzle and the nozzle partitions are not rubbed and appear to be in good condition. The integral radial spill strip shows heavy rub radially by the 1st stage bucket cover.
  - No signs of axial separation of the nozzle from the shell fit.
  - Visual indication is the nozzle is in good condition.
  - Recommendation – repairs to the integral spill strip.
  - NDE showed no indications, refer to NDE report by TEAM inc
- Rotor Row 1
  - Radial rubbing on the row 1 bucket cover leading edge. This is from contact with the integral radial spill strip on the first stage nozzle.
  - No sign of radial rubbing on the row 1 tenons

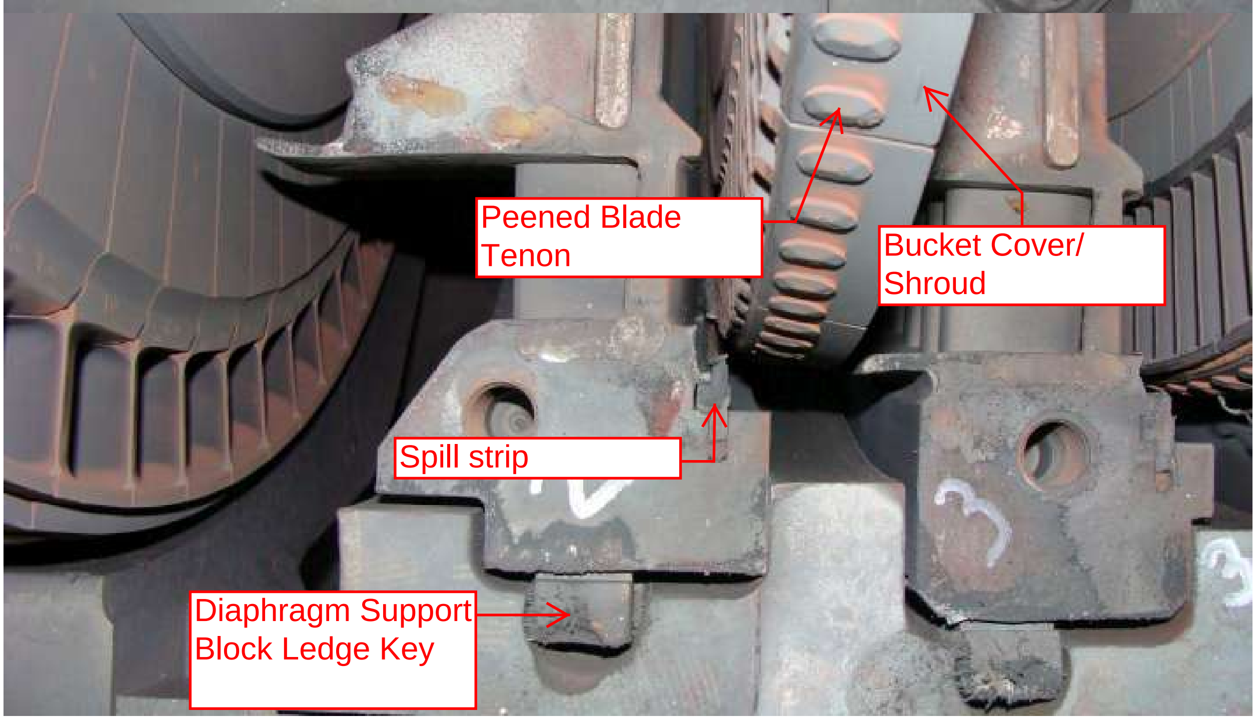
  - No sign of axial rubbing on the bucket covers other than the contact made with the integral spill strip.
  - No signs of bucket damage
  - No signs of wheel damage or axial rubbing.
- Diaphragm Stage 2
  - No sign of rubbing between diaphragm inner web and the 2nd stage wheel
  - Hard Axial rub at the outer setback face (caused by contact with bucket cover) and the inner setback face (caused by contact with bucket root appendage)
  - No signs of partition damage as viewed from the horizontal joint
  - Radial spill strip is hard rubbed radial and axial
  - Diaphragm packing in the lower half diaphragm has light to moderate rubbing in the axial and radial direction. Tooth profiles are intact.
- Rotor Row 2
  - Radial rubbing on the row 2 bucket cover leading edge. This is from contact with the radial spill strip.
  - Axial rubbing on the row 2 bucket cover leading edge. This is from contact with the outer set back face on the diaphragm.
  - Axial rubbing on the row 2 bucket at the root appendage.
  - No signs of wheel damage or axial rubbing of the wheel face to the diaphragm inner web.
  - No visible sign of bucket damage.
- Diaphragm Stage 3
  - No sign of rubbing between diaphragm inner web and the 3rd stage wheel
  - Hard Axial rub at the outer setback face (caused by contact with bucket cover) and the inner setback face (caused by contact with bucket root appendage)
  - No signs of partition damage as viewed from the horizontal joint
  - Radial spill strip is hard rubbed radial and axial
  - Diaphragm packing in the lower half diaphragm has light to moderate rubbing in the axial and radial direction. Tooth profiles are intact.
- Rotor Row 3
  - Radial rubbing on the row 3 bucket cover leading edge. This is from contact with the radial spill strip.
  - Axial rubbing on the row 3 bucket cover leading edge. This is from contact with the outer set back face on the diaphragm.
  - Axial rubbing on the row 3 bucket at the root appendage.
  - No signs of wheel damage or axial rubbing of the wheel face to the diaphragm inner web.
  - No visible sign of bucket damage.
- Diaphragm Stage 4
  - No sign of rubbing between diaphragm inner web and the 4th stage wheel

  - Hard Axial rub at the outer setback face (caused by contact with bucket cover) and the inner setback face (caused by contact with bucket root appendage)
  - No signs of partition damage as viewed from the horizontal joint
  - Radial spill strip is hard rubbed radial and axial
  - Diaphragm packing in the lower half diaphragm has light to moderate rubbing in the axial and radial direction. Tooth profiles are intact.
- Rotor Row 4
  - Radial rubbing on the row 4 bucket cover leading edge. This is from contact with the radial spill strip.
  - Axial rubbing on the row 4 bucket cover leading edge. This is from contact with the outer set back face on the diaphragm.
  - Axial rubbing on the row 4 bucket at the root appendage.
  - No signs of wheel damage or axial rubbing of the wheel face to the diaphragm inner web.
  - No visible sign of bucket damage.
- Diaphragm Stage 5
  - No sign of rubbing between diaphragm inner web and the 5th stage wheel
  - Hard Axial rub at the outer setback face (caused by contact with bucket cover) and the inner setback face (caused by contact with bucket root appendage)
  - No signs of partition damage as viewed from the horizontal joint
  - Radial spill strip is hard rubbed radial and axial
  - Diaphragm packing in the lower half diaphragm has light to moderate rubbing in the axial and radial direction. Tooth profiles are intact.
- Rotor Row 5
  - Radial rubbing on the row 5 bucket cover leading edge. This is from contact with the radial spill strip.
  - Axial rubbing on the row 5 bucket cover leading edge. This is from contact with the outer set back face on the diaphragm.
  - Axial rubbing on the row 5 bucket at the root appendage.
  - No signs of wheel damage or axial rubbing of the wheel face to the diaphragm inner web.
  - No visible sign of bucket damage.
- Diaphragm Stage 6
  - No sign of rubbing between diaphragm inner web and the 6th stage wheel
  - Hard Axial rub at the outer setback face (caused by contact with bucket cover) and the inner setback face (caused by contact with bucket root appendage)
  - No signs of partition damage as viewed from the horizontal joint
  - Radial spill strip is hard rubbed radial and axial
  - Diaphragm packing in the lower half diaphragm has light to moderate rubbing in the axial and radial direction. Tooth profiles are intact.

- Rotor Row 6
  - Radial rubbing on the row 6 bucket cover leading edge. This is from contact with the radial spill strip.
  - Axial rubbing on the row 6 bucket cover leading edge. This is from contact with the outer set back face on the diaphragm.
  - Axial rubbing on the row 6 bucket at the root appendage.
  - No signs of wheel damage or axial rubbing of the wheel face to the diaphragm inner web.
  - No visible sign of bucket damage.
- Diaphragm Stage 7
  - No sign of rubbing between diaphragm inner web and the 7th stage wheel
  - Hard Axial rub at the outer setback face (caused by contact with bucket cover) and the inner setback face (caused by contact with bucket root appendage)
  - No signs of partition damage as viewed from the horizontal joint
  - Radial spill strip is hard rubbed radial and axial
  - Diaphragm packing in the lower half diaphragm has light to moderate rubbing in the axial and radial direction. Tooth profiles are intact.
- Rotor Row 7
  - Radial rubbing on the row 7 bucket cover leading edge. This is from contact with the radial spill strip.
  - Axial rubbing on the row 7 bucket cover leading edge. This is from contact with the outer set back face on the diaphragm.
  - Axial rubbing on the row 7 bucket at the root appendage.
  - No signs of wheel damage or axial rubbing of the wheel face to the diaphragm inner web.
  - No visible sign of bucket damage.
- Diaphragm Stage 8
  - No sign of rubbing between diaphragm inner web and the 8th stage wheel
  - Hard Axial rub at the outer setback face (caused by contact with bucket cover).
  - No signs of partition damage as viewed from the horizontal joint
  - Radial spill strip is hard rubbed radial and axial
  - Diaphragm packing in the lower half diaphragm has light to moderate rubbing in the axial and radial direction. Tooth profiles are intact.
- Rotor Row 8
  - Radial rubbing on the row 8 bucket cover leading edge. This is from contact with the radial spill strip.
  - Axial rubbing on the row 8 bucket cover leading edge. This is from contact with the outer set back face on the diaphragm.
  - No signs of wheel damage or axial rubbing of the wheel face to the diaphragm inner web.

  - No visible sign of bucket damage.
- Diaphragm Stage 9
  - No sign of rubbing between diaphragm inner web and the 9th stage wheel
  - Hard Axial rub at the outer setback face (caused by contact with bucket cover) and the inner setback face (caused by contact with bucket root appendage)
  - No signs of partition damage as viewed from the horizontal joint
  - Radial spill strip is hard rubbed radial and axial
  - Diaphragm packing in the lower half diaphragm has light to moderate rubbing in the axial and radial direction. Tooth profiles are intact.
- Rotor Row 9
  - Radial rubbing on the row 9 bucket cover leading edge. This is from contact with the radial spill strip.
  - Axial rubbing on the row 9 bucket cover leading edge. This is from contact with the outer set back face on the diaphragm.
  - Axial rubbing on the row 9 bucket at the root appendage.
  - No signs of wheel damage or axial rubbing of the wheel face to the diaphragm inner web.
  - No visible sign of bucket damage.
- N1 Gland and Bolt on Gland (rotor removed)
  - The lower packing segments are severely damaged on the bottom and side – all rings
- N2 Gland (rotor removed)
  - The lower packing segments showed moderate rubbing. The packing tooth profiles are acceptable.
- N3 Gland (rotor removed)
  - The lower packing segments are severely damaged on the bottom and sides – all rings
- N4 Gland (rotor removed)
  - The lower packing segments are severely damaged on the bottom and sides – all rings
- N5 Gland (rotor removed)
  - The lower packing segments are severely damaged on the bottom and sides – all rings

Row 1 nozzle radial seal rub



Row 2/3 Diaphragm lower

Row 3 packing lower

Gland 3 shaft packing lower

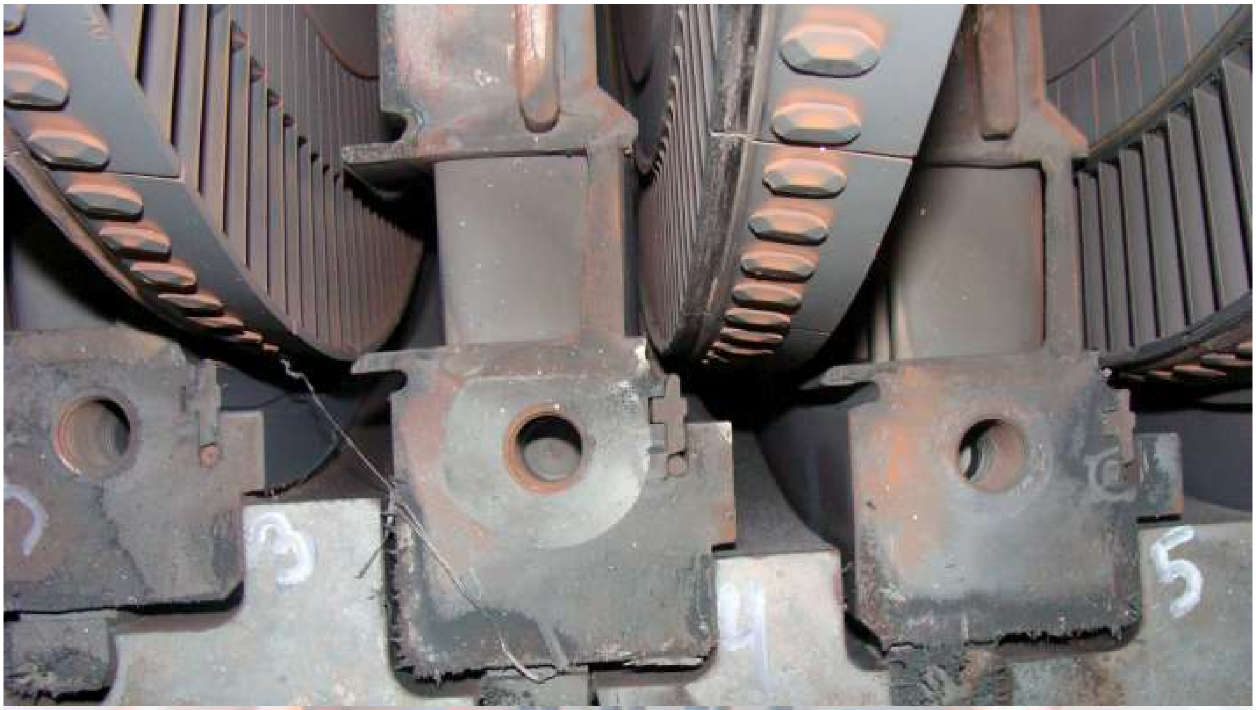
Gland 3 shaft packing lower

Row 2,3,4 diaphragm lower

Row 2 packing lower L/S

Row 2 packing lower R/S

Row 3,4,5 diaphragm lower

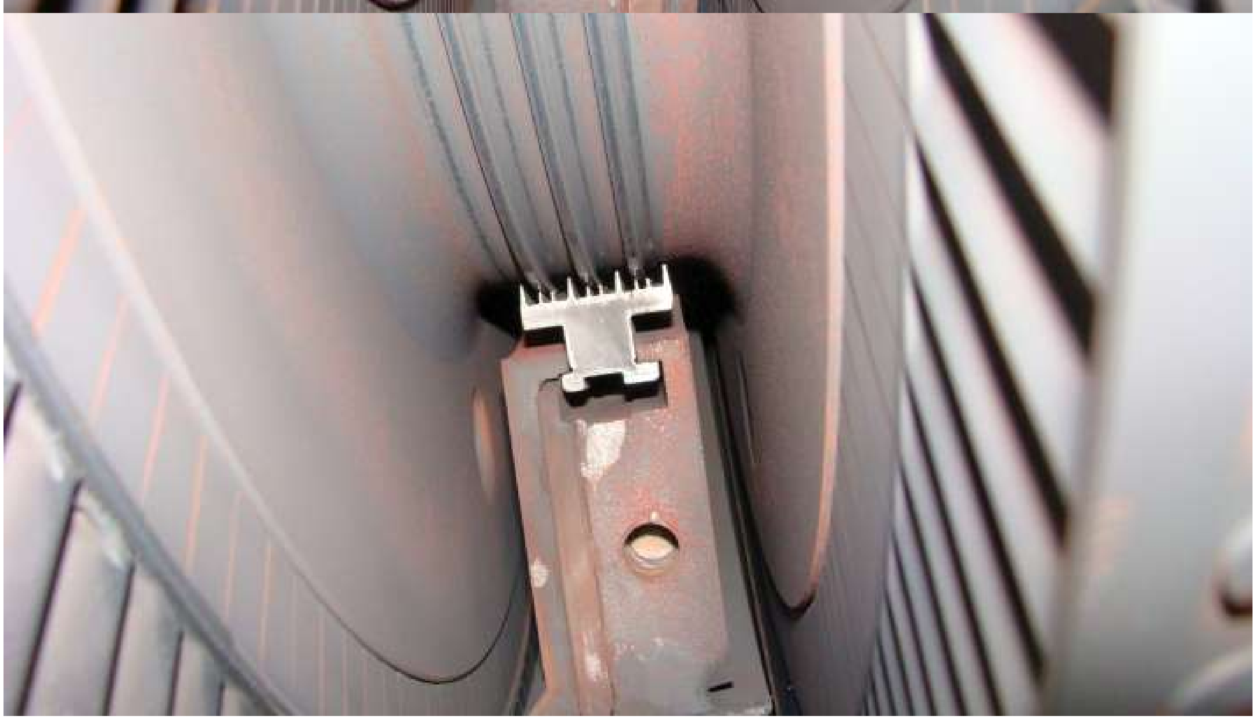


Row 4 packing lower

Row 4 packing lower

Row 4,5,6 diaphragm lower

Row 7 packing lower

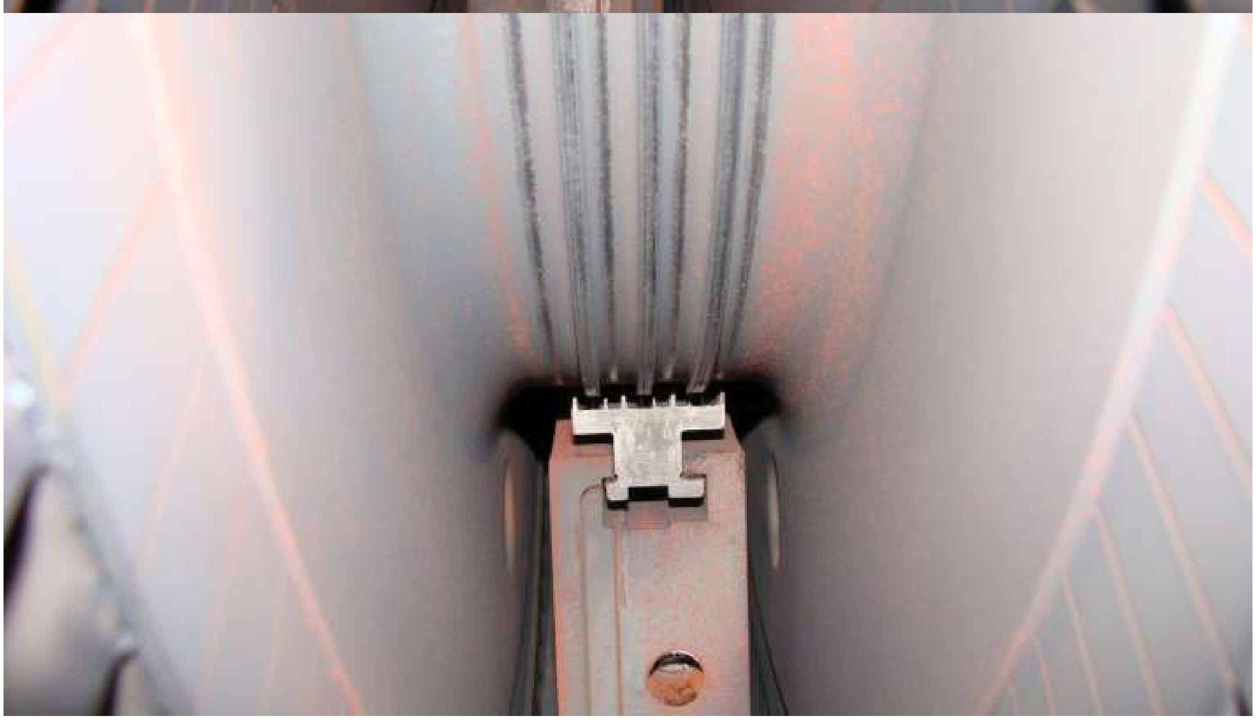


Row 7 packing lower

Row 5 packing upper installed

Row 5,6,7 diaphragm lower

Row 8 packing lower L/S



Row 8 packing lower R/S

Row 6,7,8 diaphragm lower

Row 9 packing lower L/S

Row 9 packing lower R/S

Row 7,8,9 diaphragms lower

Row 8, 9 diaphragm lower

Row 11, 12 diaphragm lower

Row 11,12 diaphragm lower

Row 11 packing lower

Row 11 packing lower

Row 11, 12 diaphragms

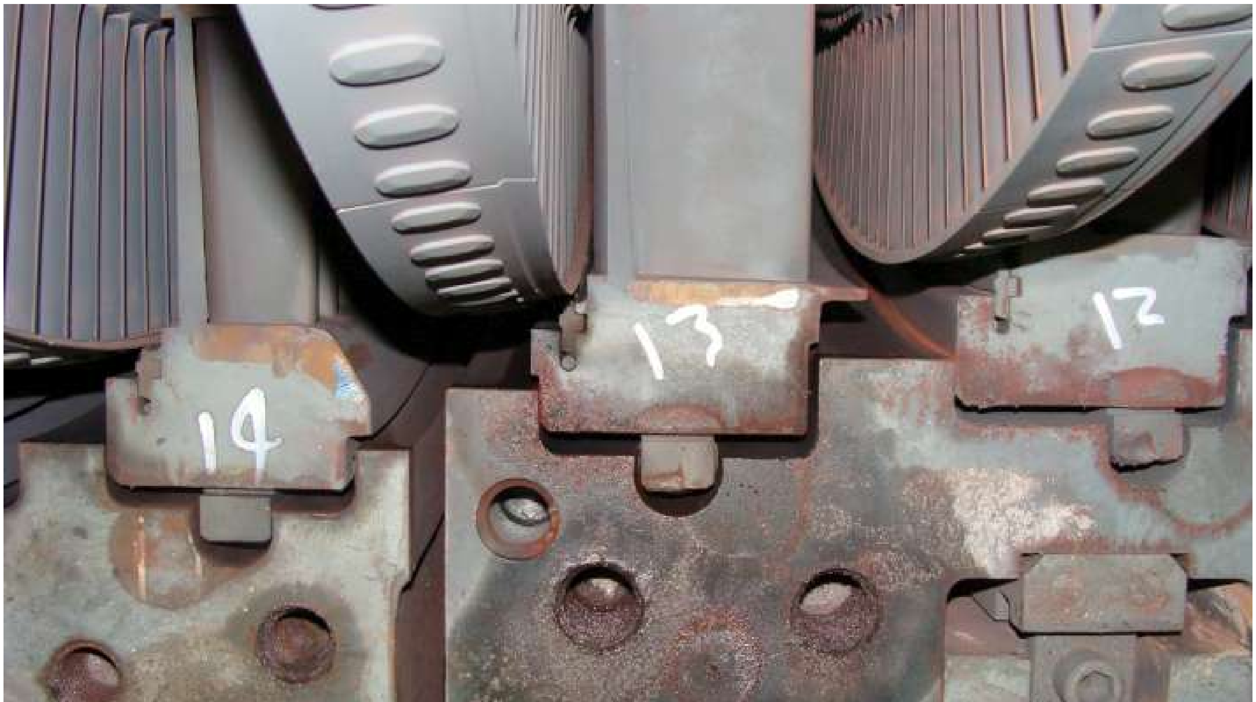
Row 12 diaphragm

Row 12 L/S packing

Row 12 R/S packing

Row 13 L/S diaphragm

Row 13 R/S diaphragm



Row 13 packing L/S

Row 13 packing R/S

Row 14 diaphragm

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Row 14 packing L/S

Row 15 diaphragm

Row 15 packing L/S

Row 16 diaphragm

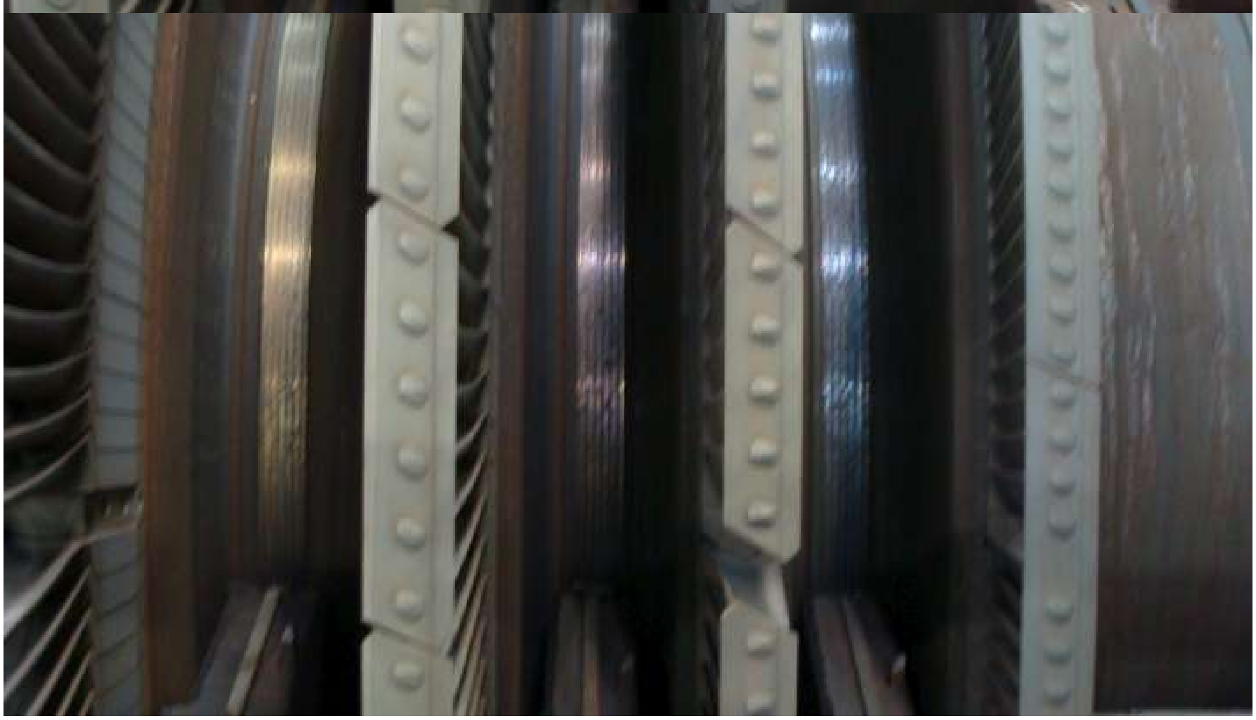
Row 16 packing L/S

Row 17 diaphragm

Row 17 packing

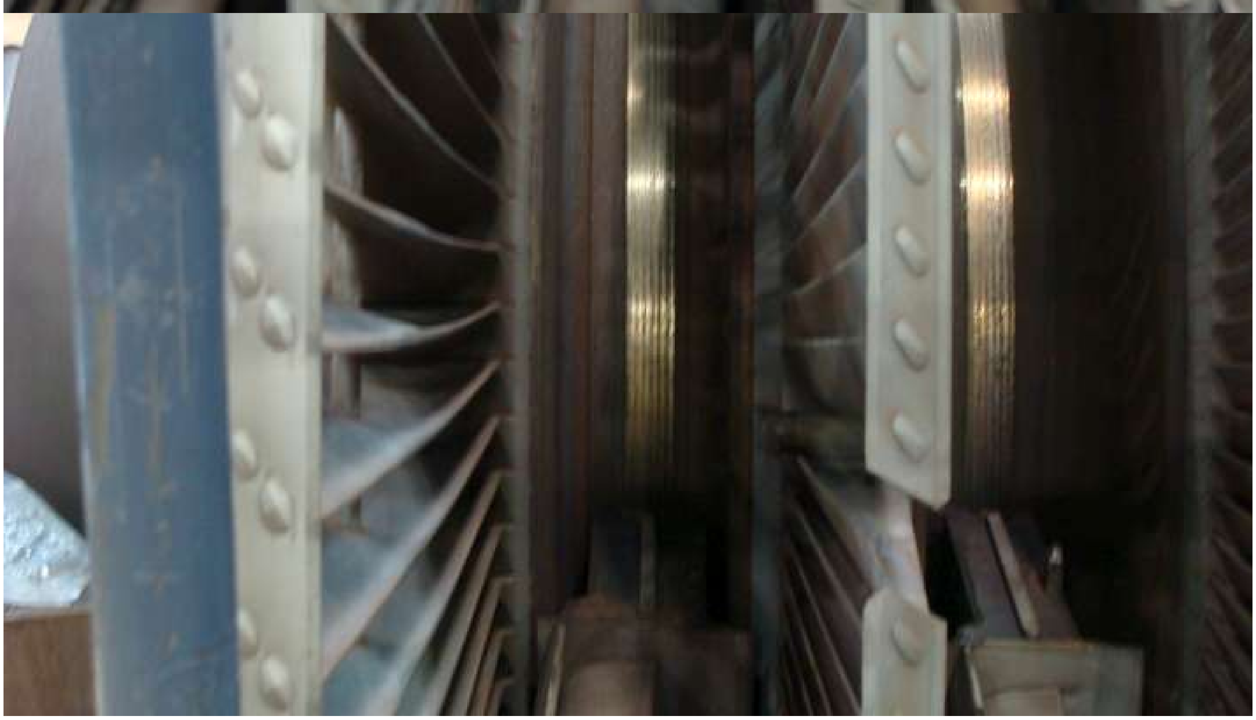
LP inlet flow divider packing

LPGE row 2 packing



LPTE row 3 packing

LPTE row 4 packing

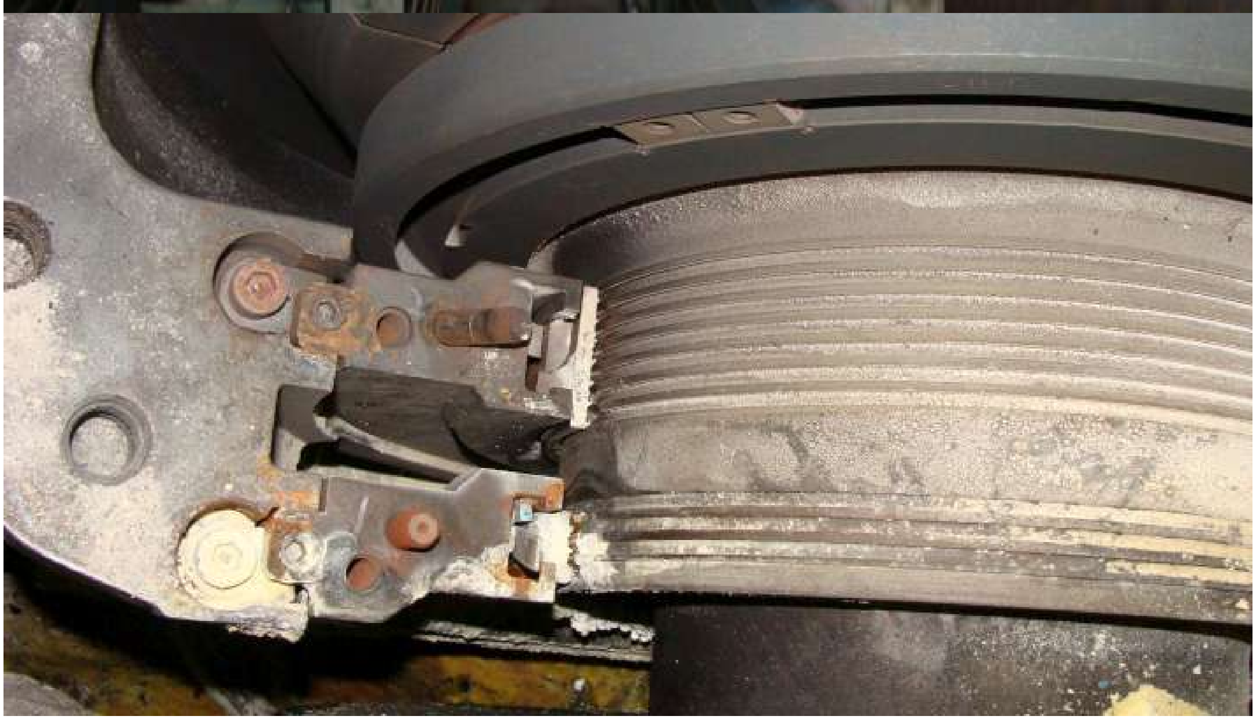


LPTE row 5 packing

LPTE row 2 spill strips

LPTE row 2,3,4 packing

LPTE row 4,5 packing

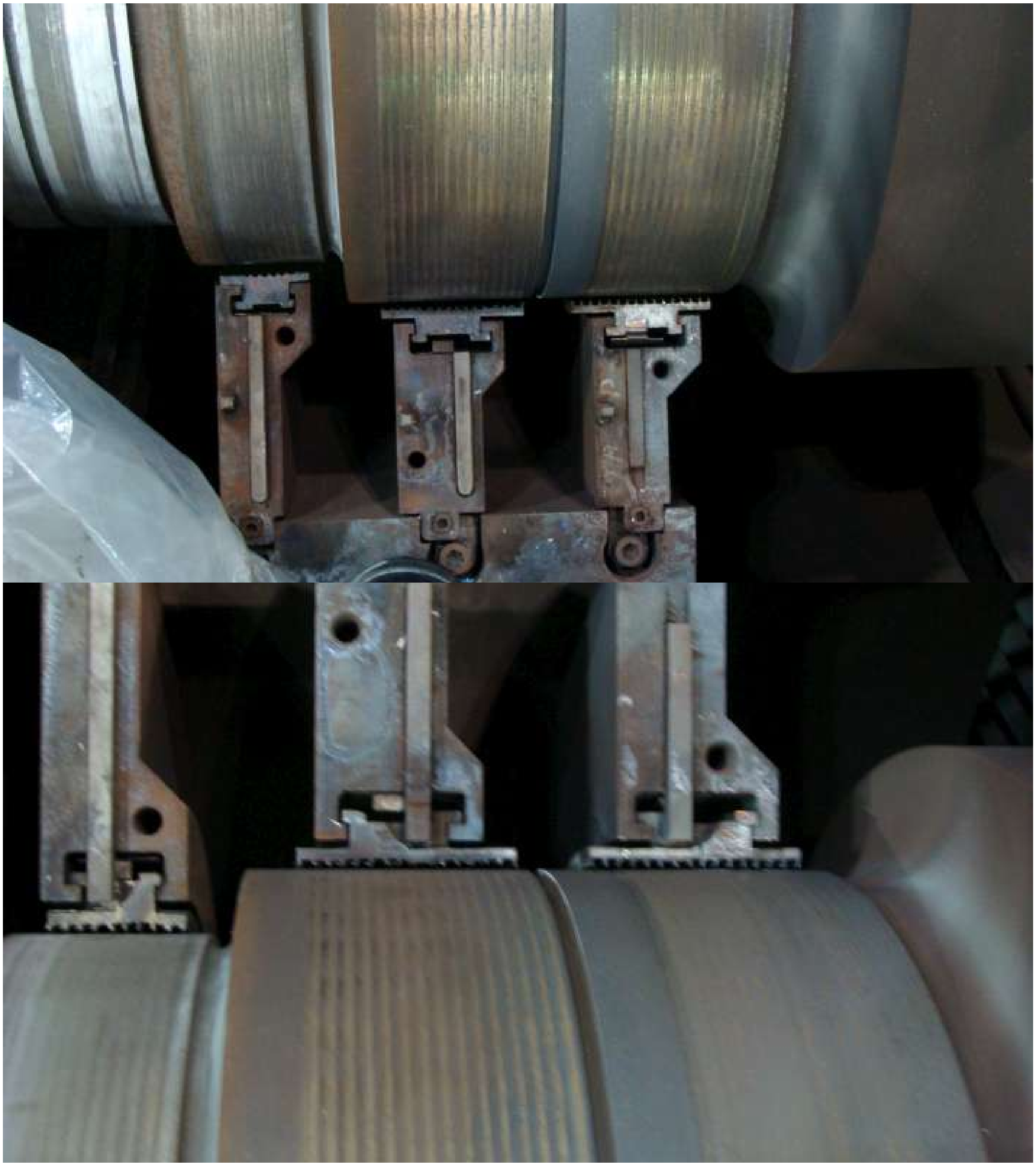


LP N3 outer gland packing

LP N4 outer gland packing

LP N3 inner gland packing

LP N4 inner gland packing



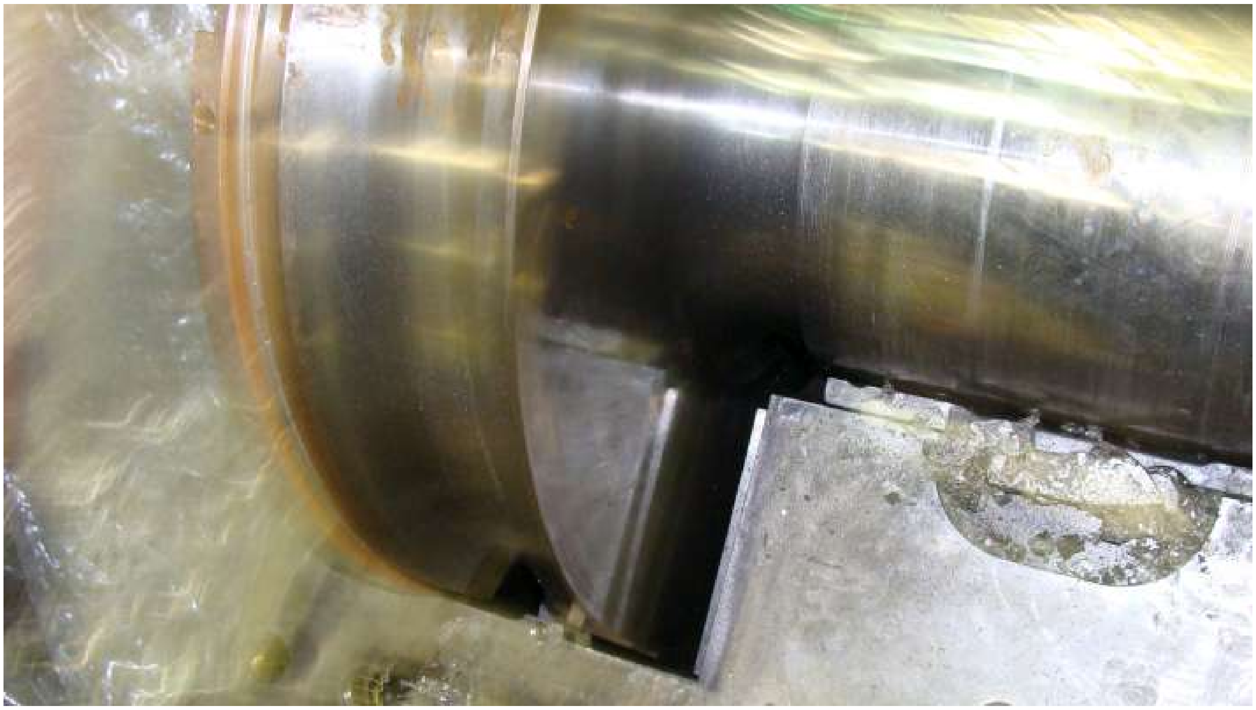
LP N4 inner gland packing

Thrust Bearing and Thrust Cage

The rear thrust pad (inactive) was removed and visually inspected. The Babbitt was melted / smeared down to the copper back plate and into the copper back plate. The front plate (active) was found to be in fair condition with minimal visual damage.

The seal ring in the thrust cage separating the front and rear plates, is heavily damaged from radial rub. This is the same condition as was found in the phase 1 inspection.

Thrust runner condition



Active thrust pad condition

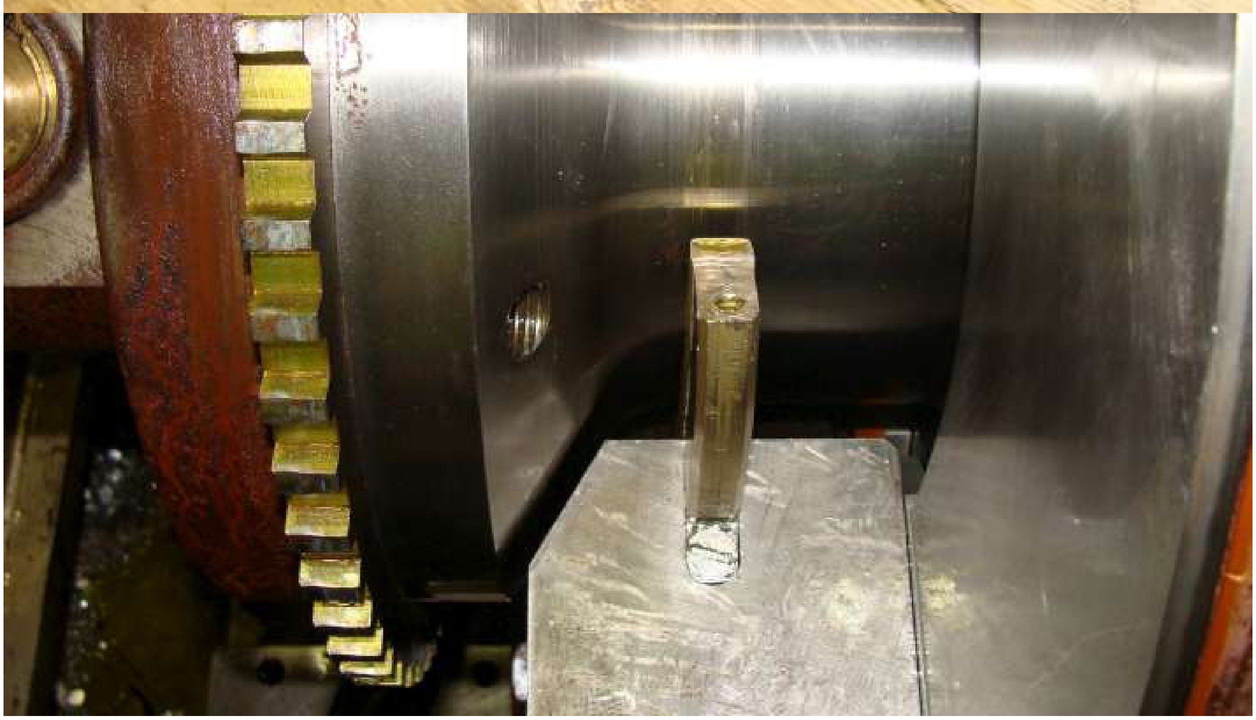
Active side thrust plates

Damage to active side thrust plates

Thrust plate damage

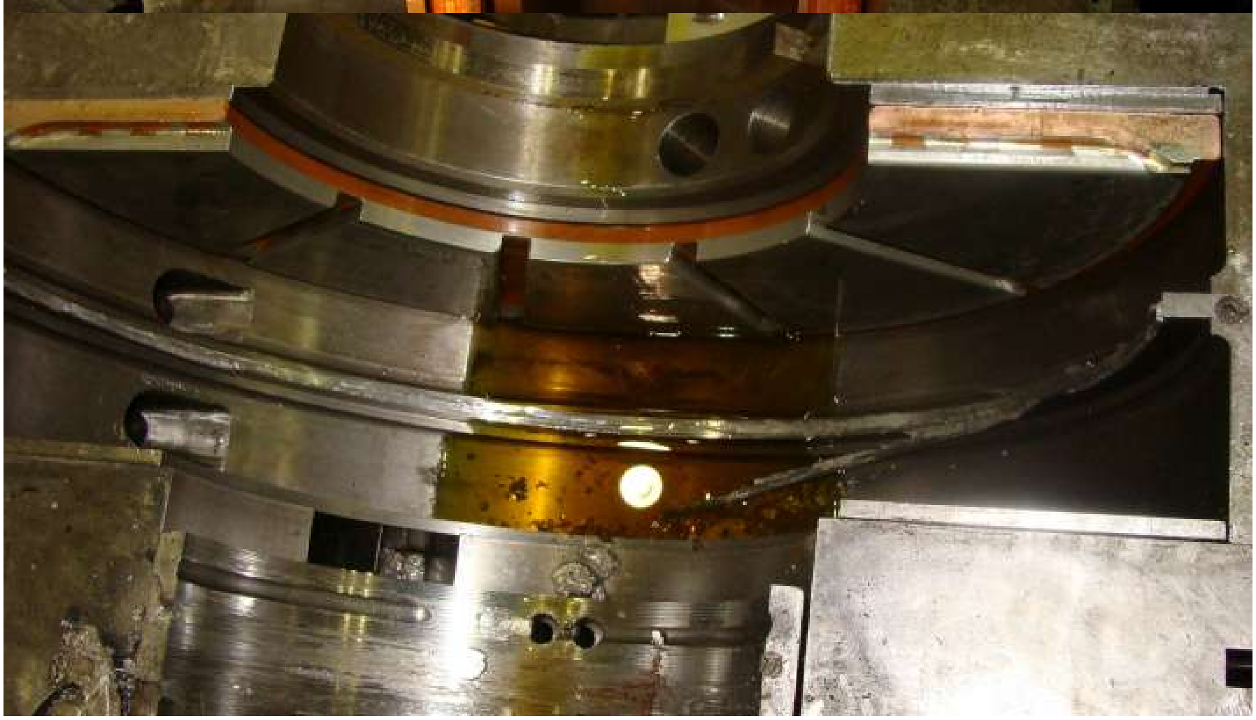
Thrust plate damage

Seal ring rolled and damaged



Seal ring rolled, keeper damaged

Thrust bearing assembled



Debris in bottom of thrust cavity

Thrust runner condition

T1 Bearing Lower Half

The lower half T1 Bearing was visually inspected upon rotor removal. The Babbitt in the liner is worn down to the liner itself.

T2 Bearing lower half

The lower half T2 Bearing was visually inspected upon rotor removal. The Babbitt is melted down to the shell and dovetails. This bearing has been extremely hot as the Babbitt appears to be burned and covered in soot.

T3 Bearing lower half

The lower half T3 Bearing was visually inspected upon rotor removal. The Babbitt is melted and down to the shell and dovetails.

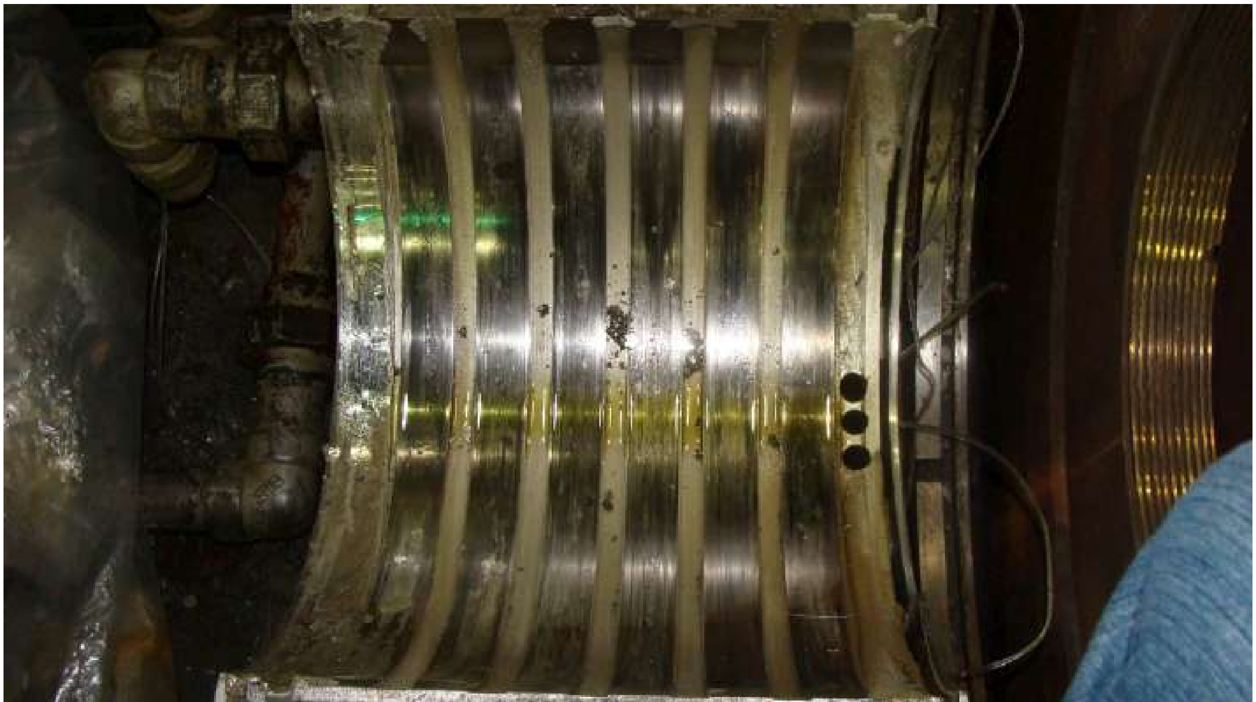
Bearing Pedestals

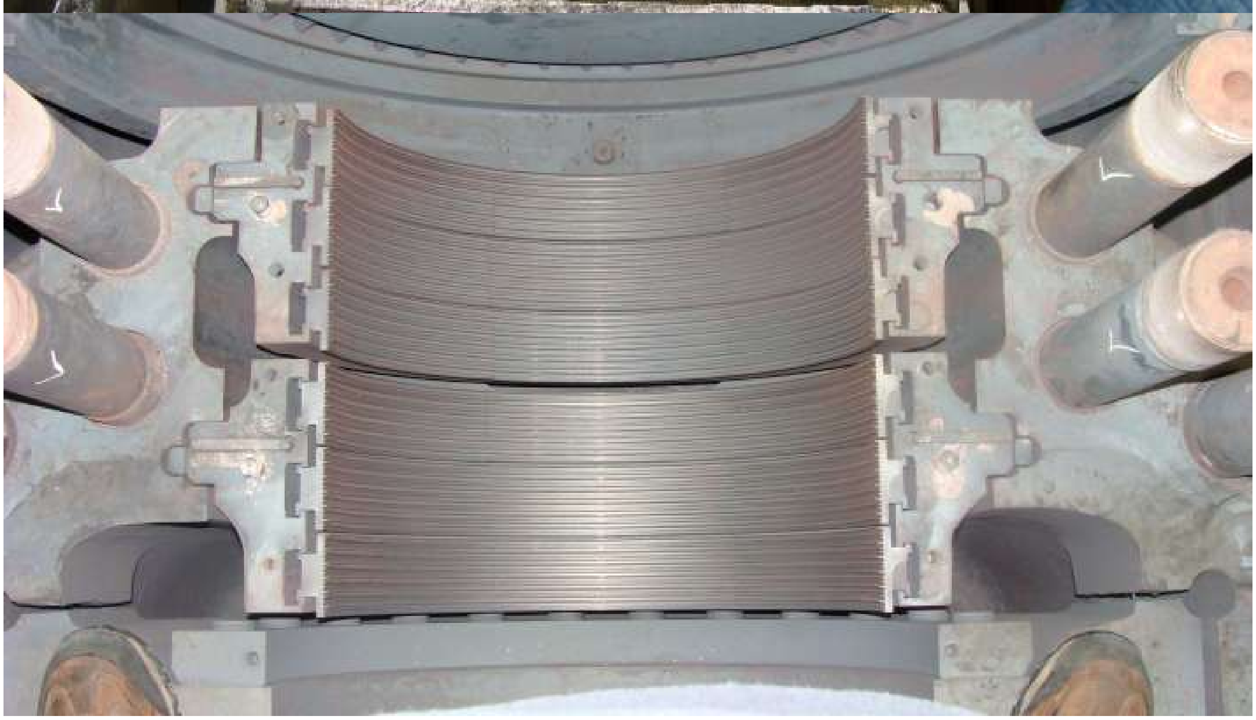
The bearing pedestals have been manually cleaned. All supply and return oil piping in the pedestal areas was removed and cleaned if possible. The number 2 supply pipe was blown out with air. The detraining tank was opened up, inspected, and manually cleaned of babbit and debris.

Bearing Support Pads

The bearing support pads were installed on the new bearings #2 and #3 to check for bearing position and contact checks. Both bearings were found to be out of "final" position from the radial bore readings from the last outage. The blue contact checks indicated very poor contact. It will be necessary to machine the backs of the pads to re-establish acceptable contact on the support pads. Additional work will also be necessary to the upper pads to successfully establish contact and proper pinch from the upper ring.

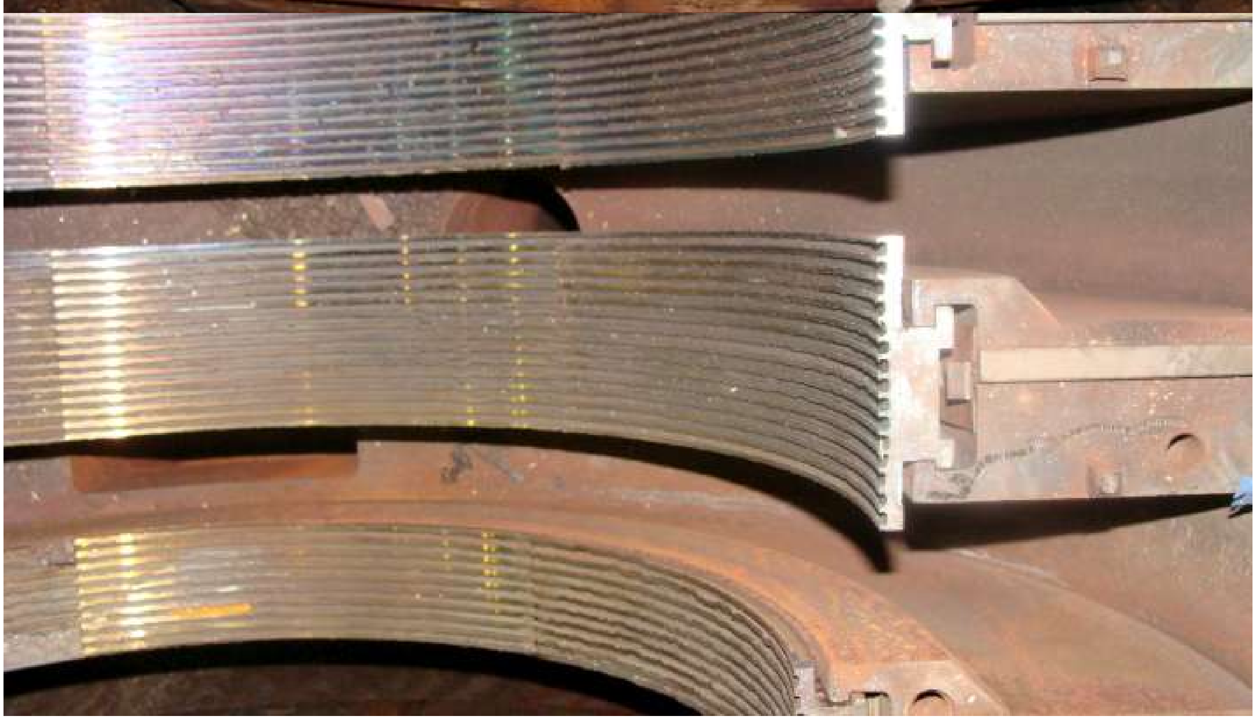
L/H T2 Bearing





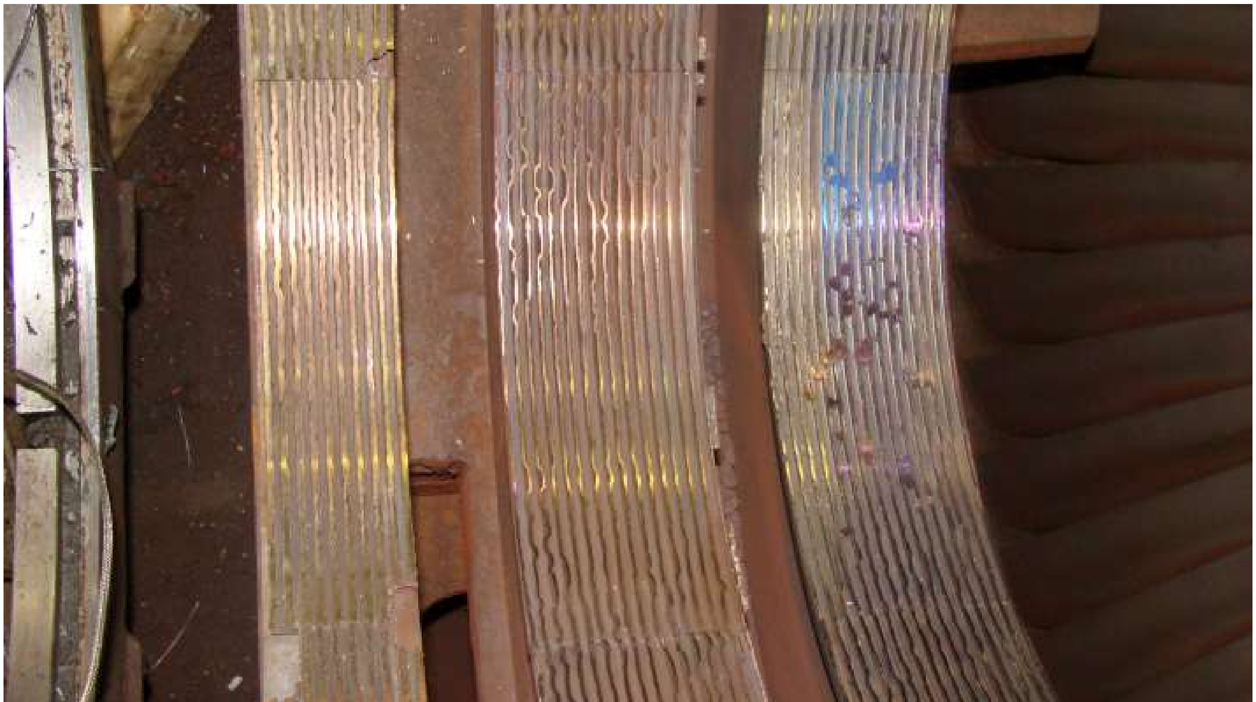
L/H N2 packing gland

L/H N3 packing gland



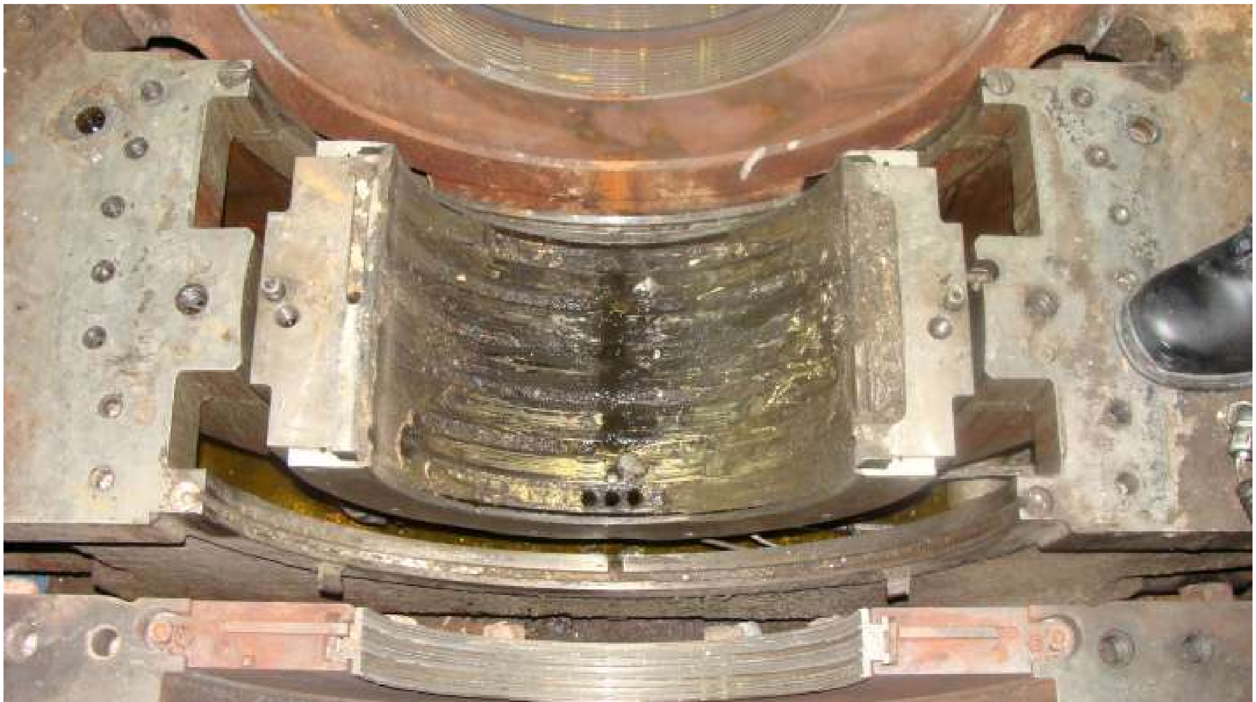
L/H N4 packing gland

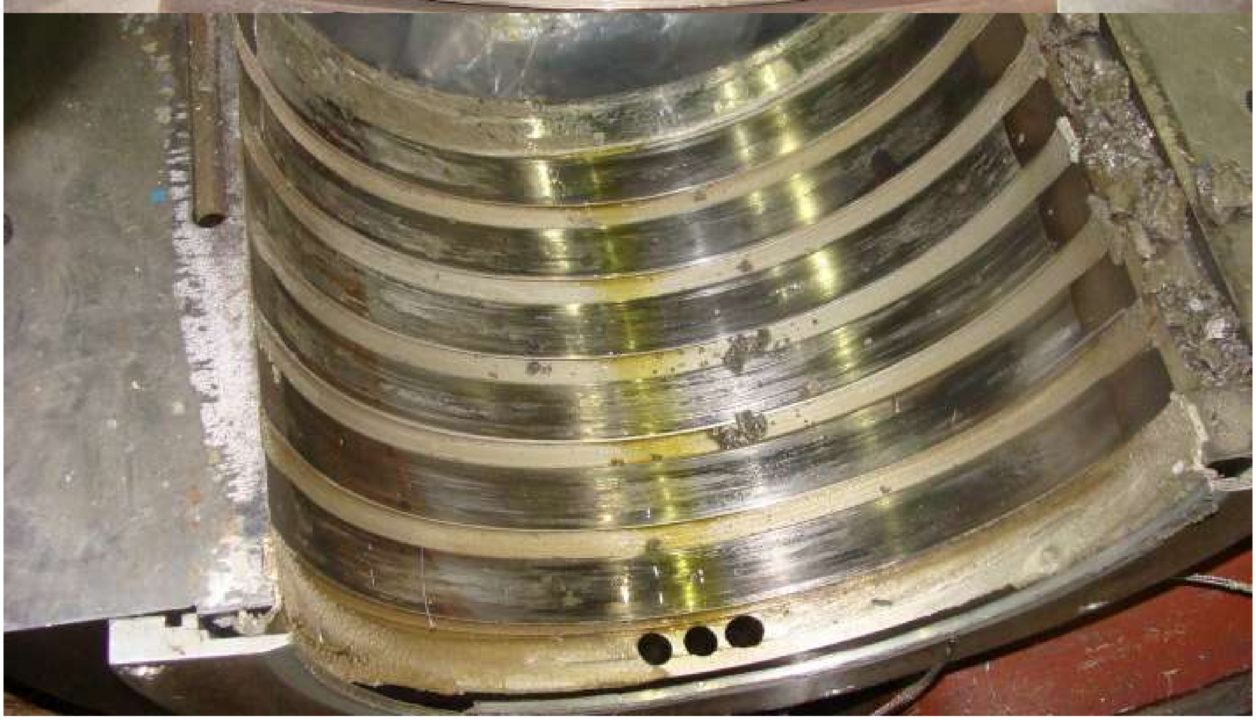
L/H N5 packing gland



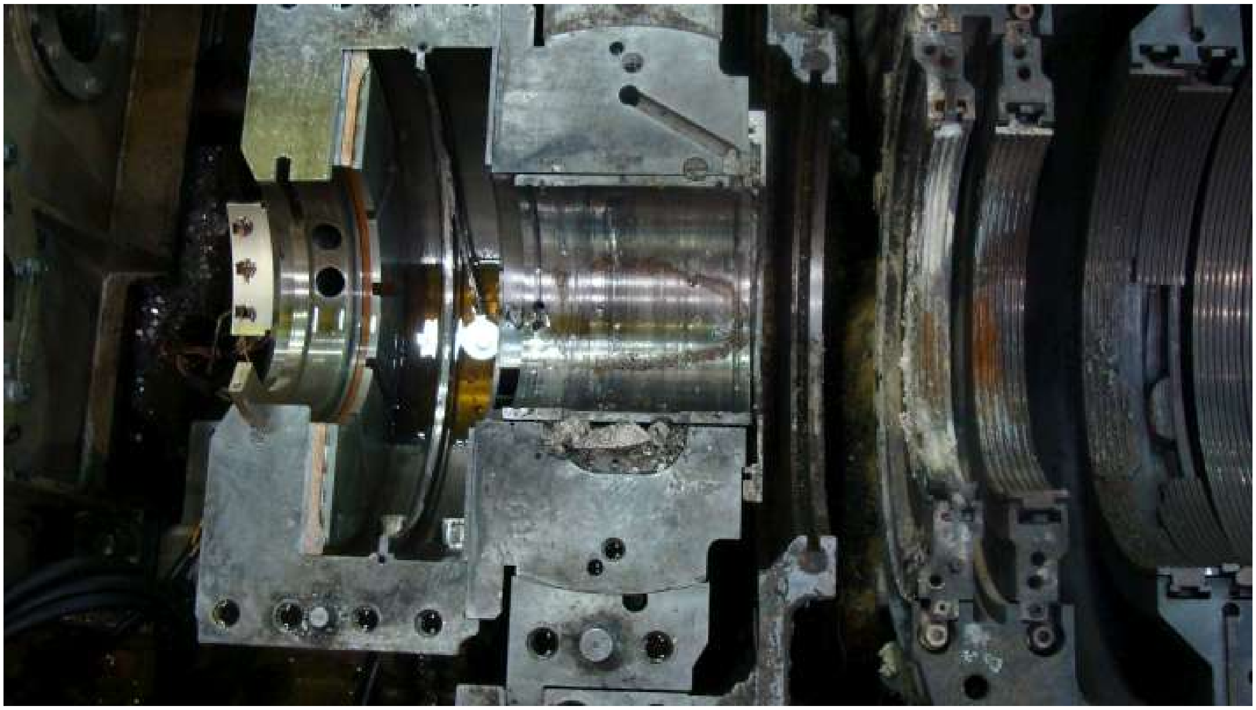
T2 Bearing L/H

T2 Bearing L/H





T3 Bearing L/H



T1 LH Bearing and Thrust

Main Lube Oil Tank

The main lube oil tank was drained by customer and Alstom brought in a vacuum truck to remove the remaining oil and residue from the tank. Babbit was found in the bottom of the tank.

The lube oil pumps (2) AC pumps and (1) DC pumps were removed from tank for inspection. All couplings were intact, and all 3 pumps could be freely turned by hand. The pumps were disassembled and inspected. AC pump 1 shaft was found with approximately 8 mils runout, and will be replaced. The DC pump thrust bearing was found with a black burnt oil/grease mixture. The bearing turned freely, but was replaced. The thrust bearing casing seal was found damaged and was replaced. The DC oil pump impeller was found installed correctly. The dimensions were verified, and the part numbers were a match. From a mechanical standpoint, there were no findings that would have prevented the pump from operating effectively.

All 4 check valves inside the lube oil tank were operated and witnessed by customer. All valves were operating correctly. It was necessary to vacuum out the oil tank a second time.

The lines from the DC oil pump to the common header were boroscoped and found clear. This was witnessed by customer.

The Lube Oil coolers have been pressure tested in place and all coolers have held 35 psig for 1 hour periods. Coolers are not leaking. Coolers were removed, and sent off site for cleaning. Babbit material was found throughout cooling fins.

The following is a full visual survey of the Steam Turbine Rotor following removal from the unit:

Test Certificate

Title

Turbine Rotor Inspection Checklist

Number of Stages___27______

Solid ☒ Built Up ☐

CODE		
X - Work Carried Out	C - See Comments	UT - Ultrasonic
N - Not Done	V - Visual Inspection	PT - Penetrant
NA - Not Applicable	MP - Mag. Particle	

Inspection & Checks

Check Rotor Bow		Insp. Tie Wires	x
Remove Deposit Sample		Insp. Wheel Faces	x
Check Ph of Deposit		Insp. Wheel Radii	x
Blast Clean		Insp. Water Impeller(s)	x
Rotor Test Inspections		Insp. Impeller Casing(s)	x
- Buckets		Insp. Slinger(s)	x
- Bore		Insp. Bore Plug	
- Dovetails		Insp. Journals	x
- Peripherals		Insp. Cplg. Rabbet(s)	x
- Dovetail Pins		Insp. Cplg. Faces	x
- Erosion Shields		Insp. Cplg. Bolt Holes	x
Insp. Bkt. Covers	x	Insp. Stm Balance Holes	x
Insp. Bucket Tenions	x	- In Buckets	x
Insp. Bkt. Vanes, Roots	x	- In Wheels	x
Backs	x	Insp. Solid Particle Erosion	x
Insp. Balance Holes	x	Insp. for Water Induction	x
Grooves	x		
Insp. Heat Grooves	x		
Insp. Notch Blocks			
Insp. Packing Grooves			

Comments:___Visual Inspection with rotor removed from the unit_______________________

Test Decision (as required/acc. to specification)	**Accepted*** / **NC-Report***	**Rejected*** / **Rework***	Unit / System Name: Holyrood Unit 1	
NCR No.*			Part Text: Steam Turbine Rotor	Quantity
Checked by**: Chris Kenyon			Part Idnr / Rev.	Power Station Designation
Approved by**: RM Scott			I & T Plan ID / Rev.	Test Step / Material Test No.
Authority / Customer**			Order No.	Factory Order
ALSTOM			Sheet No.: 1 / No. of Sh.: 10	Document No.: UTGS 623106 / Rev.: -

* Mark/Fill in if applicable ** Name / dept. / date / initials

Test Certificate

Title: **Turbine Rotor Visual Inspection**

CONDITION		VISUAL INSPECTION FINDINGS		
THRUST RUNNER	GOOD	Both front and rear faces of the thrust runner are in good condition. No scoring is evident. Can be used as is.		
T1 JOURNAL	GOOD	The T1 rotor journal has Babbitt deposits on the shaft around approximately 50% of the surface. Scoring and gouging is not indicated. Re-inspect after cleaning.		
T1 OIL DEFLECTOR JOURNAL	GOOD	The T1 oil deflector locations is in good condition. The area shows cardox buildup and should be cleaned thoroughly.		
N1 SHAFT GLAND	GOOD	The inner and outer N1 shaft gland is in good condition. The area shows indications of light radial rubbing. Clean up and use as is.		
ROW 9	COVERS	Shows light radial and heavy axial rubbing on inlet side of covers. Cover lifting is not evident.		
	BUCKET DISCHARGE	No significant findings.		
	BUCKET INLET	Typical FOD can be seen.		
	LOCKING SEGMENT	Intact, pin migration not seen.		
	BLADE ROOT	Appendage indicates medium axial rub.		
	PKG LANDS	Lands indicate light radial rubbing.		
	# OF BUCKETS	129	# BUCKET GROUPS	25
ROW 8	COVERS	Shows light radial and medium to heavy axial rubs. Cover lifting is not evident.		
	BUCKET DISCHARGE	No significant findings.		
	BUCKET INLET	Typical FOD can be seen.		
	LOCKING SEGMENT	Intact, pin migration not seen.		
	PKG LANDS	Lands indicate light radial rubbing.		
	BLADE ROOT	Appendage shows no signs of rubbing.		
	# OF BUCKETS	127	# BUCKET GROUPS	25
ROW 7	COVERS	Covers indicate light radial and medium axial rubs. Cover lifting not present.		
	BUCKET DISCHARGE	No significant findings.		

Unit / System Name	Order No.		Factory Order	
Holyrood Unit 1				
ALSTOM	Sheet No. 2	No. of Sh. 10	Document No. UTGS692999	Rev. -

Test Certificate

Title

Turbine Rotor Visual Inspection

	BUCKET INLET	Typical FOD seen.		
	LOCKING SEGMENT	Intact, pin migration not seen.		
	PKG LANDS	Light radial rubbing seen.		
	BLADE ROOT	Appendage indicates medium axial rubs.		
	# OF BUCKETS	121	# BUCKET GROUPS	24
ROW 6	COVERS	Covers indicate light radial and heavy to severe axial rubs. Cover lifting not seen.		
ROW 6	BUCKET DISCHARGE	No significant findings.		
ROW 6	BUCKET INLET	Typical FOD seen.		
ROW 6	LOCKING SEGMENT	Intact, pin migration not seen.		
ROW 6	PKG LANDS	Lands indicate light radial rubbing.		
ROW 6	BLADE ROOT	Appendage shows heavy to severe axial rubs.		
ROW 6	# OF BUCKETS	124	# BUCKET GROUPS	24
ROW 5	COVERS	Covers show medium radial and severe axial rubbing. Cover lifting is not seen.		
ROW 5	BUCKET DISCHARGE	No significant findings		
ROW 5	BUCKET INLET	Typical FOD seen.		
ROW 5	LOCKING SEGMENT	Intact, pin migration not seen.		
ROW 5	PKG LANDS	Lands indicate light radial rubbing.		
ROW 5	BLADE ROOT	Appendate shows heavy axial rubs.		
ROW 5	# OF BUCKETS	157	# BUCKET GROUPS	39
ROW 4	COVERS	Covers show medium radial and heavy axial rubs. Cover lifting not seen.		
ROW 4	BUCKET DISCHARGE	No significant findings.		
ROW 4	BUCKET INLET	Typical FOD seen.		
ROW 4	LOCKING SEGMENT	Intact, pin migration not seen.		
ROW 4	PKG LANDS	Lands show light radial rubbing.		
ROW 4	BLADE ROOT	Appendage shows medium axial rubbing.		
ROW 4	# OF BUCKETS	156	# BUCKET GROUPS	30
ROW 3	COVERS	Covers show heavy radial and heavy axial rubs. Slight cover lifting can be seen on some of the covers.		
ROW 3	BUCKET DISCHARGE	No significant findings.		
ROW 3	BUCKET INLET	Typical FOD seen.		

Unit / System Name	Order No.			Factory Order
Holyrood Unit 1				
ALSTOM	Sheet No. 3	No. of Sh. 10	Document No. UTGS692999	Rev. -

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Test Certificate

Title: **Turbine Rotor Visual Inspection**

	LOCKING SEGMENT	Intact, no pin migration.		
	PKG LANDS	Lands indicate light radial rubbing.		
	BLADE ROOT	Appendage indicates heavy axial rubs.		
	# OF BUCKETS	153	# BUCKET GROUPS	30
ROW 2	COVERS	Covers show severe radial and axial rubs. Eight of the covers have the entire leading edge of the cover missing. Cover lifting at the exit side is evident.		
	BUCKET DISCHARGE	No significant findings.		
	BUCKET INLET	Typical FOD seen.		
	LOCKING SEGMENT	Intact, pin migration not seen.		
	PKG LANDS	Lands show light radial rubbing.		
	BLADE ROOT	Appendage indicates heavy to severe axial rubs.		
	# OF BUCKETS	150	# BUCKET GROUPS	30
ROW 1	COVERS	Covers show severe radial nad medium axial rubs. Cover lifting can be seen.		
	BUCKET DISCHARGE	No significant findings.		
	BUCKET INLET	Typical FOD can be seen.		
	LOCKING SEGMENT	Intact, no pin migration seen.		
	PKG LANDS	N/A		
	BLADE ROOT	Appendage shows light axial rubbing.		
	# OF BUCKETS	66	# BUCKET GROUPS	11
N2 SHAFT GLAND	GOOD	Indicates light radial rubbing. Clean up area and re-use.		
ROW 11	COVERS	Covers indicate light axial rub. No lifting seen.		
	BUCKET DISCHARGE	No significant findings.		
	BUCKET INLET	Typical FOD seen.		
	LOCKING SEGMENT	Intact, no pin migration seen.		
	PKG LANDS	Lands indicate light radial rubbing.		
	WHEEL	No significant findings.		
	# OF BUCKETS	179	# BUCKET GROUPS	44
ROW 12	COVERS	Covers indicate light radial rubbing. No lifting evident.		

Unit / System Name	Order No.	Factory Order			
Holyrood Unit 1					
	Sheet No.	No. of Sh.	Document No.		Rev.
ALSTOM	4	10	UTGS692999		-

Test Certificate

Title

Turbine Rotor Visual Inspection

	BUCKET DISCHARGE	No significant findings.		
	BUCKET INLET	Typical FOD seen.		
	LOCKING SEGMENT	Intact, no pin migration seen.		
	PKG LANDS	Lands indicate light radial rubbing.		
	WHEEL	No significant findings		
	# OF BUCKETS	151	# BUCKET GROUPS	37
ROW 13	COVERS	Covers indicate light radial and axial rubbing. Cover lifting not evident.		
	BUCKET DISCHARGE	No significant findings.		
	BUCKET INLET	Typical FOD seen.		
	LOCKING SEGMENT	Intact, no pin migration seen.		
	PKG LANDS	Lands indicate light radial rubbing.		
	WHEEL	No significant findings No significant findings		
	# OF BUCKETS	153	# BUCKET GROUPS	30
ROW 14	COVERS	Covers indicate light radial rubbing. Cover lifting not evident.		
	BUCKET DISCHARGE	No significant findings.		
	BUCKET INLET	Typical FOD seen.		
	LOCKING SEGMENT	Intact, no pin migration seen.		
	PKG LANDS	Lands indicate light radial rubbing.		
	WHEEL	No significant findings.		
	# OF BUCKETS	155	# BUCKET GROUPS	31
ROW 15	COVERS	Covers indicate light radial rubbing. Cover lifting not evident.		
	BUCKET DISCHARGE	No significant findings.		
	BUCKET INLET	Typical FOD seen.		
	LOCKING SEGMENT	Intact, no pin migration seen.		
	PKG LANDS	Lands indicate light radial rubbing.		
	WHEEL	No significant findings		
	# OF BUCKETS	117	# BUCKET GROUPS	23
ROW 16	COVERS	Covers indicate light radial rubbing. Cover lifting not evident.		
	BUCKET DISCHARGE	No significant findings.		

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Title: **Turbine Rotor Visual Inspection**

	BUCKET INLET	Typical FOD seen.			
	LOCKING SEGMENT	Intact, no pin migration seen.			
	PKG LANDS	Lands indicate light radial rubbing.			
	WHEEL	No significant findings			
	# OF BUCKETS	185	# BUCKET GROUPS	21	
ROW 17	COVERS	Covers indicate heavy to severe radial rubbing. Tenon material has been significantly reduced. Cover lifting not evident.			
	BUCKET DISCHARGE	No significant findings.			
	BUCKET INLET	Typical FOD seen.			
	LOCKING SEGMENT	Intact, no pin migration seen.			
	PKG LANDS	Lands indicate light radial rubbing.			
	WHEEL	No significant findings			
	# OF BUCKETS	185	# BUCKET GROUPS	21	
N3 SHAFT GLAND	GOOD	No signs of damage. Clean up and reuse.			
T2 INBOARD DEFLECTOR JOURNAL	GOOD	No signs of damage. Clean up and reuse.			
T2 JOURNAL	SLIGHT DAMAGE	Babbitt deposits on journal area can be seen. Possible slight scoring of the journal has occurred. Need to clean journal and re-inspect.			
T2 OUTBOARD DEFLECTOR JOURNAL	GOOD	No signs of damage. Clean up and reuse.			
N4 SHAFT GLAND	GOOD	No signs of damage. Clean up and reuse.			
IP/LP COUPLING	GOOD	Lock tabs are in place. No signs of nut movement.			

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Turbine Rotor Visual Inspection

LP 5TE	COVERS	Covers intact. No signs of rubbing. Tie wires intact.		
	BUCKET DISCHARGE	No significant findings.		
	BUCKET INLET	No significant findings.		
	LOCKING SEGMENT	Intact, pin migration not seen.		
	PKG LANDS	Lands indicate light radial rubbing.		
	WHEEL	No significant findings.		
	# OF BUCKETS		# BUCKET GROUPS	
LP 4TE	COVERS	Covers indicate light to medium radial rubs. Tie wires intact.		
	BUCKET DISCHARGE	No significant findings.		
	BUCKET INLET	No significant findings.		
	LOCKING SEGMENT	Intact, pin migration not seen.		
	PKG LANDS	Lands indicate light radial rubbing.		
	WHEEL	No significant findings.		
	# OF BUCKETS		# BUCKET GROUPS	
LP 3TE	COVERS	Covers indicate light radial rubs. Tie wires intact.		
	BUCKET DISCHARGE	No significant findings.		
	BUCKET INLET	No significant findings.		
	LOCKING SEGMENT	Intact, pin migration not seen.		
	PKG LANDS	Lands indicate light radial rubbing.		
	WHEEL	No significant findings.		
	# OF BUCKETS		# BUCKET GROUPS	
LP 2TE	COVERS	Covers indicate light radial rubs. Tie wires intact.		
	BUCKET DISCHARGE	No significant findings.		
	BUCKET INLET	No significant findings.		
	LOCKING SEGMENT	Intact, pin migration not seen.		
	PKG LANDS	Lands indicate light radial rubbing.		
	WHEEL	No significant findings.		
	# OF BUCKETS		# BUCKET GROUPS	

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Title: **Turbine Rotor Visual Inspection**

LP 1TE	COVERS	Covers indicate light radial rubs. Tie wires intact.		
	BUCKET DISCHARGE	No significant findings.		
	BUCKET INLET	No significant findings.		
	LOCKING SEGMENT	Intact, pin migration not seen.		
	PKG LANDS	Lands indicate light radial rubbing.		
	WHEEL	No significant findings.		
	# OF BUCKETS		# BUCKET GROUPS	
LP 1GE	COVERS	No rubs indicated. Covers and tie wires intact.		
	BUCKET DISCHARGE	No significant findings.		
	BUCKET INLET	No significant findings.		
	LOCKING SEGMENT	Intact, pin migration not seen.		
	PKG LANDS	Lands indicate light radial rubbing.		
	WHEEL	No significant findings.		
	# OF BUCKETS		# BUCKET GROUPS	
LP 2GE	COVERS	No rubs indicated. Covers and tie wires intact.		
	BUCKET DISCHARGE	No significant findings.		
	BUCKET INLET	No significant findings.		
	LOCKING SEGMENT	Intact, pin migration not seen.		
	PKG LANDS	Lands indicate light radial rubbing.		
	WHEEL	No significant findings.		
	# OF BUCKETS		# BUCKET GROUPS	
LP 3GE	COVERS	No rubs indicated. Covers and tie wires intact.		
	BUCKET DISCHARGE	No significant findings.		
	BUCKET INLET	No significant findings.		
	LOCKING SEGMENT	Intact, pin migration not seen.		
	PKG LANDS	Lands indicate light radial rubbing.		
	WHEEL	No significant findings.		
	# OF BUCKETS		# BUCKET GROUPS	
LP 4GE	COVERS	No rubs indicated. Covers and tie wires intact.		

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Turbine Rotor Visual Inspection

	BUCKET DISCHARGE	No significant findings.		
	BUCKET INLET	No significant findings.		
	LOCKING SEGMENT	Intact, pin migration not seen.		
	PKG LANDS	Lands indicate light radial rubbing.		
	WHEEL	No significant findings.		
	# OF BUCKETS		# BUCKET GROUPS	
LP 5GE	COVERS	No rubs indicated. Covers and tie wires intact.		
	BUCKET DISCHARGE	No significant findings.		
	BUCKET INLET	No significant findings.		
	LOCKING SEGMENT	Intact, pin migration not seen.		
	PKG LANDS	Lands indicate light radial rubbing.		
	WHEEL	No significant findings.		
	# OF BUCKETS		# BUCKET GROUPS	
N5 SHAFT GLAND	GOOD	No damage seen. Can be cleaned and reused.		
T3 INBOARD DEFLECTOR JOURNAL	GOOD	No damage seen. Can be cleaned and reused.		
T3 JOURNAL		Babbitt deposits can be seen on the journal area. Slight scoring may be present. Clean and re-inspect.		
	SLIGHT DAMAGE			
TB / GEN COUPLING	GOOD	No damage seen.		
	SLIGHT DAMAGE			
	SEVER DAMAGE			
T3 OUTBOARD DEFLECTOR JOURNAL	GOOD	No damage seen. Can be cleaned and reused.		

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As a rule of thumb, an increase in packing and spill strip clearances of 50% could be expected to result in a loss of approximately 2.4 MW in operation. Of this loss, a little more than half would be expected to be a result of the spill strip clearances. The actual clearance increases are on average higher than 50% as can be seen in the Tables. Also, the readings provided are left and right. The bottom readings, if available, would have had higher percentages than the measurements shown. It should be noted that other losses, for example due to roughness of the steam path surfaces, would also be significant but are not considered in the above. **Note:** The results and performance numbers stated herein are provided for information purposes only and are not a guarantee, undertaking, representation, covenant or promise.

Below is table estimating the increase in clearance of the Spill Strips

Location	Expected Clearance	Original Tooth	Measured Tooth		Tooth Wear		Percent Increase	
			Left	Right	Left	Right	Left	Right
HP9	0.025	0.190	0.000	0.000	0.190	0.190	760%	760%
HP8	0.025	0.190	0.000	0.000	0.190	0.190	760%	760%
HP7	0.025	0.110	NA	NA	NA	NA	NA	NA
HP6	0.025	0.110	NA	NA	NA	NA	NA	NA
HP5	0.025	0.190	NA	NA	NA	NA	NA	NA
HP4	0.025	0.190	0.000	0.000	0.190	0.190	760%	760%
HP3	0.025	0.190	0.075	0.072	0.115	0.118	460%	472%
HP2	0.025	0.190	0.000	0.000	0.190	0.190	760%	760%
IP11	0.025	0.190	0.145	0.143	0.045	0.047	180%	188%
IP12	0.025	0.190	0.180	0.180	0.010	0.010	40%	40%
IP13	0.025	0.110	0.097	0.095	0.013	0.015	52%	60%
IP14	0.025	0.110	0.083	0.081	0.027	0.029	108%	116%
IP15	0.025	0.110	0.080	0.080	0.030	0.030	120%	120%
IP16	0.025	0.110	0.070	0.073	0.040	0.037	160%	148%
IP17	0.025	0.110	0.084	0.081	0.026	0.029	104%	116%
LP5 TE	0.448	NA	NA	NA	NA	NA	NA	NA
LP4 TE	0.145	0.250	0.191	0.191	0.059	0.059	41%	41%
LP3 TE	0.145	0.250	0.207	0.206	0.043	0.044	30%	30%
LP2 TE	0.120	0.250	0.187	0.185	0.063	0.065	53%	54%
LP1 TE	0.120	0.250	0.226	0.223	0.024	0.027	20%	23%
LP1 GE	0.120	0.250	0.245	0.245	0.005	0.005	4%	4%
LP2 GE	0.120	0.250	0.197	0.197	0.053	0.053	44%	44%
LP3 GE	0.145	0.250	0.245	0.245	0.005	0.005	3%	3%
LP4 GE	0.145	0.250	0.222	0.220	0.028	0.030	19%	21%
LP5 GE	0.448	NA	NA	NA	NA	NA	NA	NA

Note the HP and IP spill strips are supplied at 0.170" and 0.250" with 0.06" stock for custom fit. The above assumes that the full 0.06" was removed during fitting and consequently gives the most conservative estimate of percent increase.

Below is table estimating the increase in diaphragm packing clearances.

Location	2012		2013		Percent Increase	
	Left	Right	Left	Right	Left	Right
HP9	0.017	0.03	0.085	0.076	400%	153%
HP8	0.021	0.021	0.076	0.036	262%	71%
HP7	0.022	0.028	0.061	0.031	177%	11%
HP6	0.022	0.019	0.061	0.028	177%	47%
HP5	0.025	0.02	0.067	0.028	168%	40%
HP4	0.018	0.02	0.06	0.021	233%	5%
HP3	0.024	0.021	0.061	0.047	154%	124%
HP2	0.035	0.04	0.064	0.045	83%	13%
N2-R1	0.033	0.03	0.066	0.04	100%	33%
N2-R2	0.035	0.06	0.061	0.065	74%	8%
N2-R3	0.032	0.065	0.067	0.071	109%	9%
N2-R4	0.036	0.03	0.041	0.052	14%	73%
N2-R5	0.032	0.038	0.041	0.06	28%	58%
N2-R6	0.03	0.026	0.036	0.031	20%	19%
IP11	0.065	0.02	0.055	0.081	-15%	305%
IP12	0.041	0.035	0.053	0.056	29%	60%
IP13	0.037	0.03	0.026	0.071	-30%	137%
IP14	0.02	0.017	0.025	0.076	25%	347%
IP15	0.021	0.015	0.025	0.021	19%	40%
IP16	0.03	0.1	0.075	0.071	150%	-29%
IP17	0.03	0.04	0.096	0.101	220%	153%
LP5 TE	0.01	0.036	0.051	0.075	410%	108%
LP4 TE	0.011	0.044	0.021	0.066	91%	50%
LP3 TE	0.01	0.039	0.017	0.07	70%	79%
LP2 TE	0.01	0.045	0.016	0.07	60%	56%
LP Centre	0.009	0.03	0.025	0.065	178%	117%
LP2 GE	0.015	0.035	0.03	0.077	100%	120%
LP3 GE	0.018	0.048	0.047	0.07	161%	46%
LP4 GE	0.016	0.04	0.055	0.08	244%	100%
LP5 GE	0.015	0.043	0.066	0.085	340%	98%

HP/LP coupling bolts

N1 outer gland area

LP/Gen coupling

LPGE stage 1 covers

LPGE stage 1,2 covers

LPGE stage 3 covers

LPGE stage 4 covers

LPGE stage 5 covers

LPTE stage 1 cover rub

LPTE stage 2 cover rub

LPTE stage 3 cover rub

LPTE stage 3 cover rub

LPTE stage 4 cover rub

LPTE stage 4 cover rub

LPTE stage 5

LPTE stage 5

N2 packing gland location

N3 packing gland location

N4 packing gland location

N5 packing gland location

Stage 1 blade root rub

Stage 1 blade integral cover rub

Stage 1 integral cover rub and cover position

Stage 1 integral cover rub

Row 2 blade root rub

Row 2 blade root rub

Row 2 cover partially missing material

Row 2 partially missing cover material

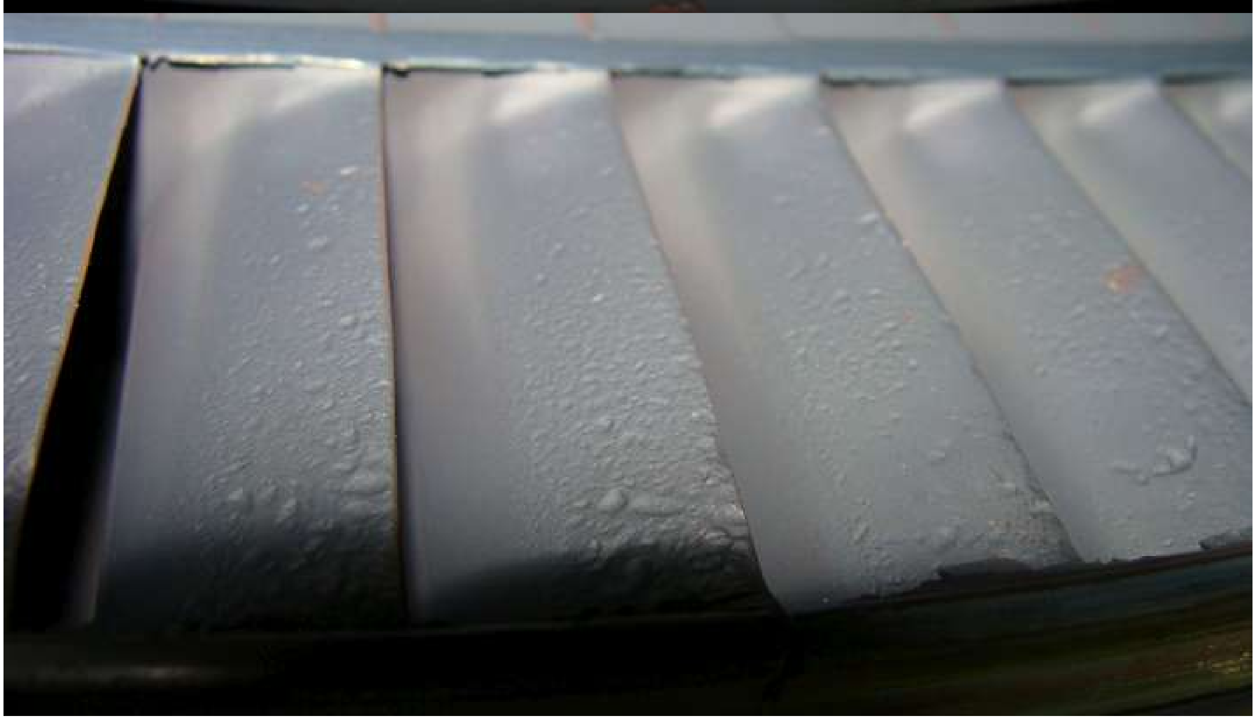
Row 2 heavy rubs

Row 2 blade inlet condition

Row 2 blade root rub

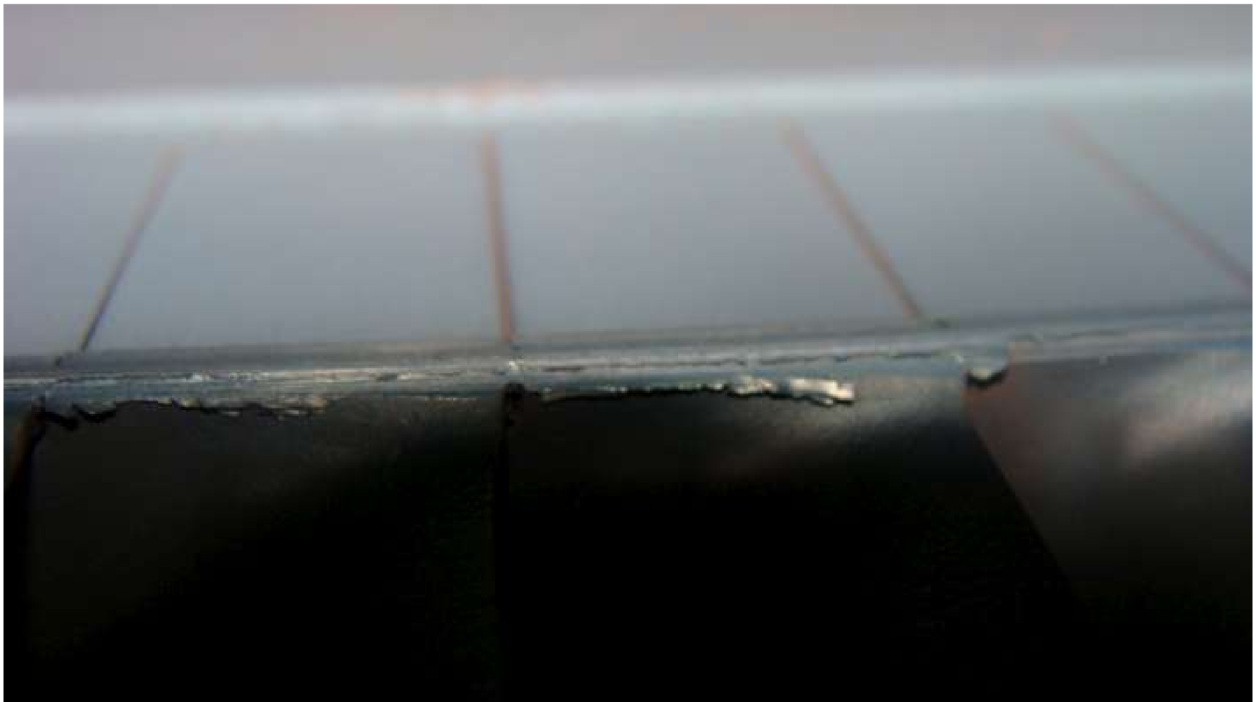
Row 2 blade exit condition

Row 3 cover condition, heavy rubs



Row 3 blade root rub and inlet condition

Row 3 blade root rub



Row 4 cover condition

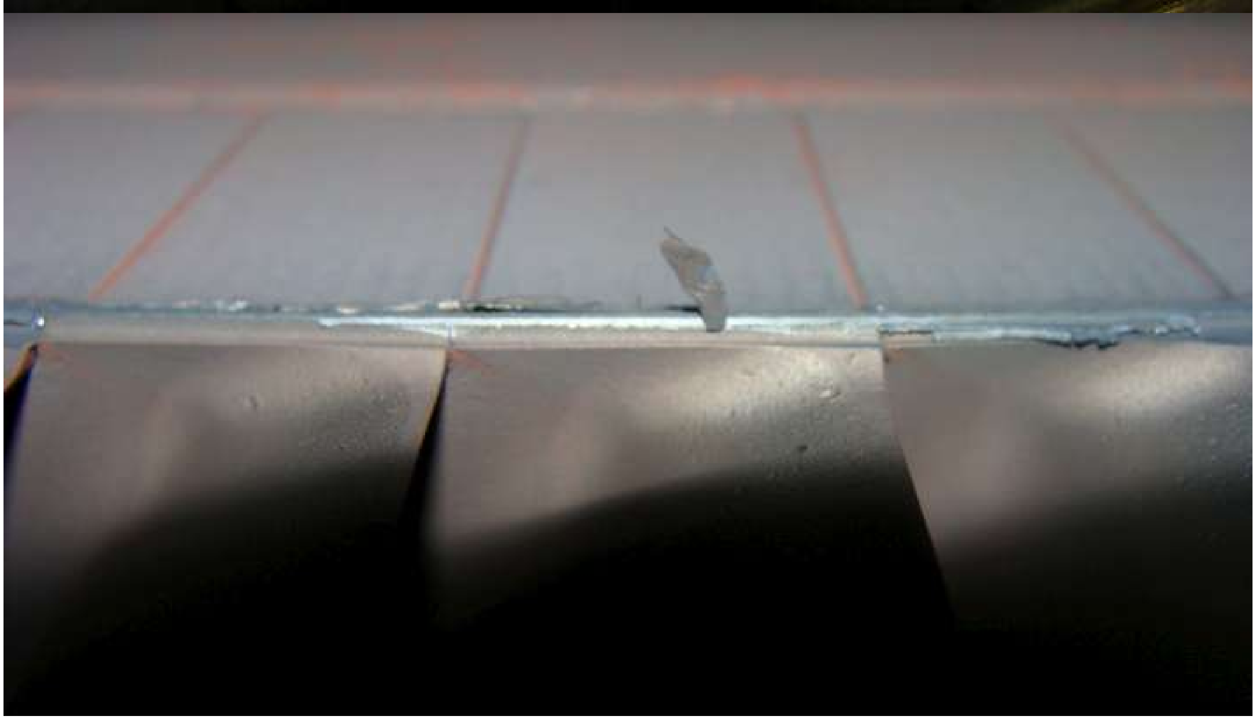
Row 4 blade inlet condition

Row 4 tenon and cover condition

Row 4 blade root rub

Row 5 cover and tenon condition

Row 5 blade inlet condition



Row 5 blade root rub

Row 6 cover and tenon condition

Row 6 blade inlet condition

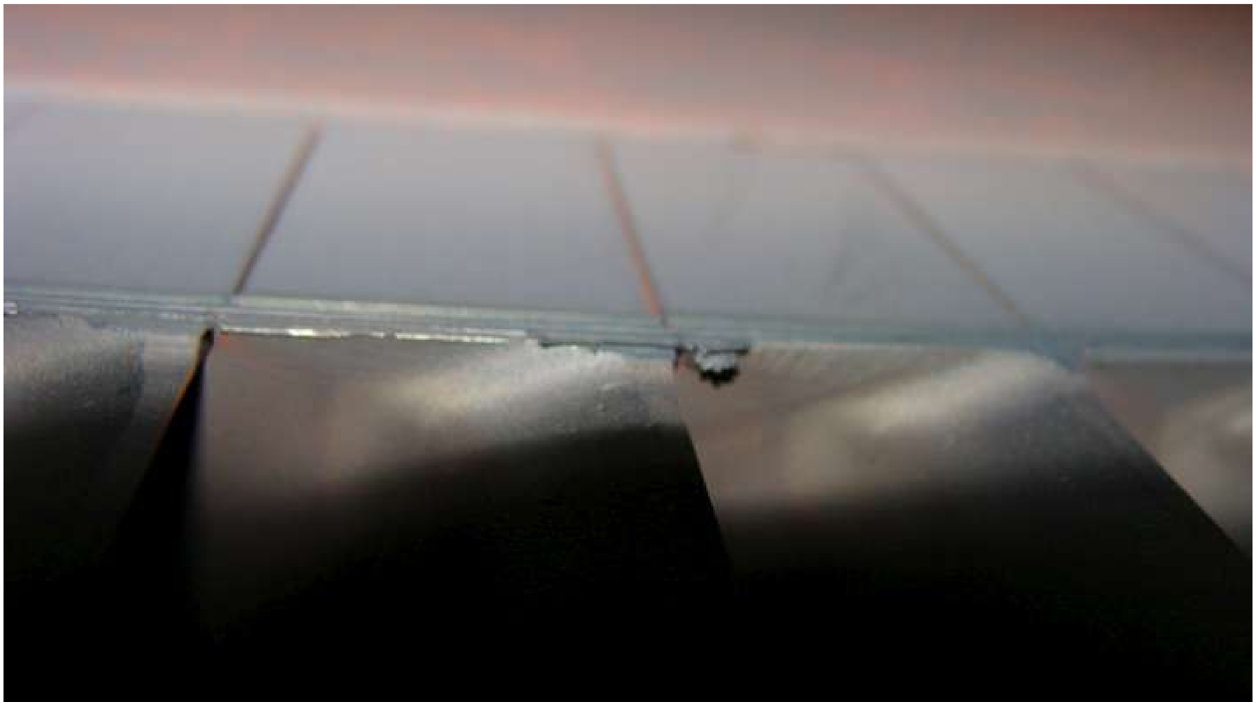
Row 6 tenon condition

Row 7 cover and tenon condition

Row 7 blade inlet condition

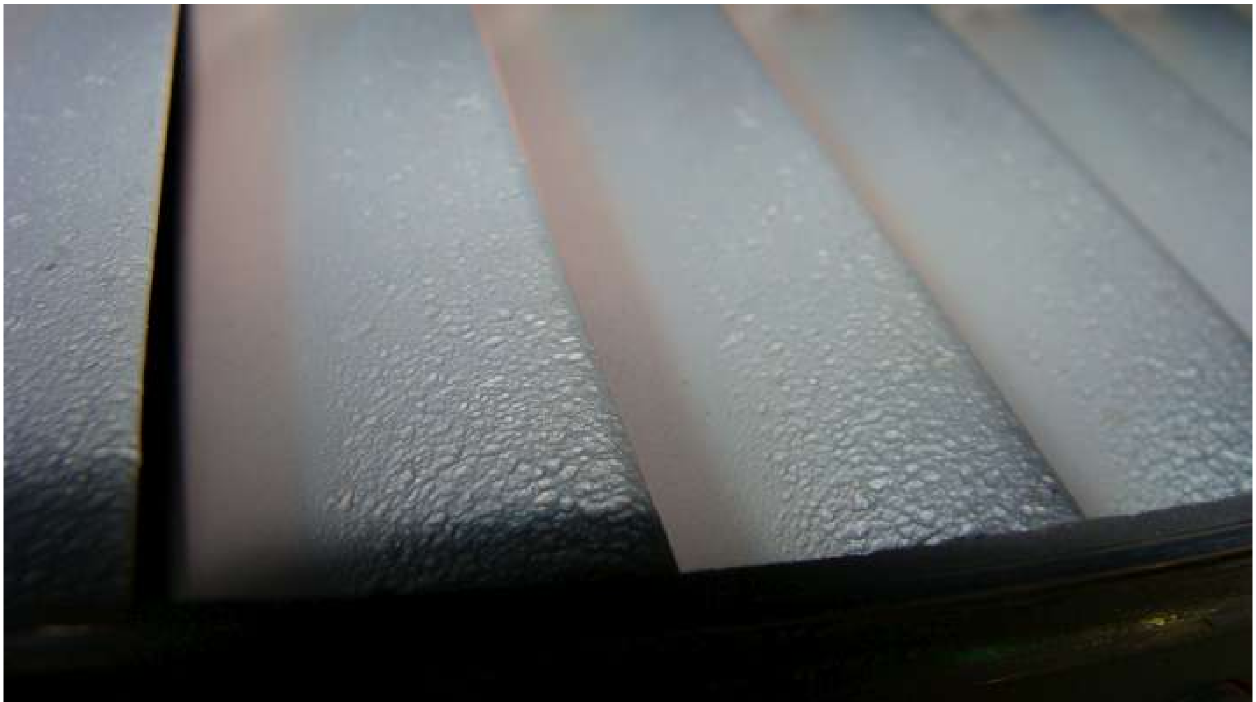
Row 7 tenon condition

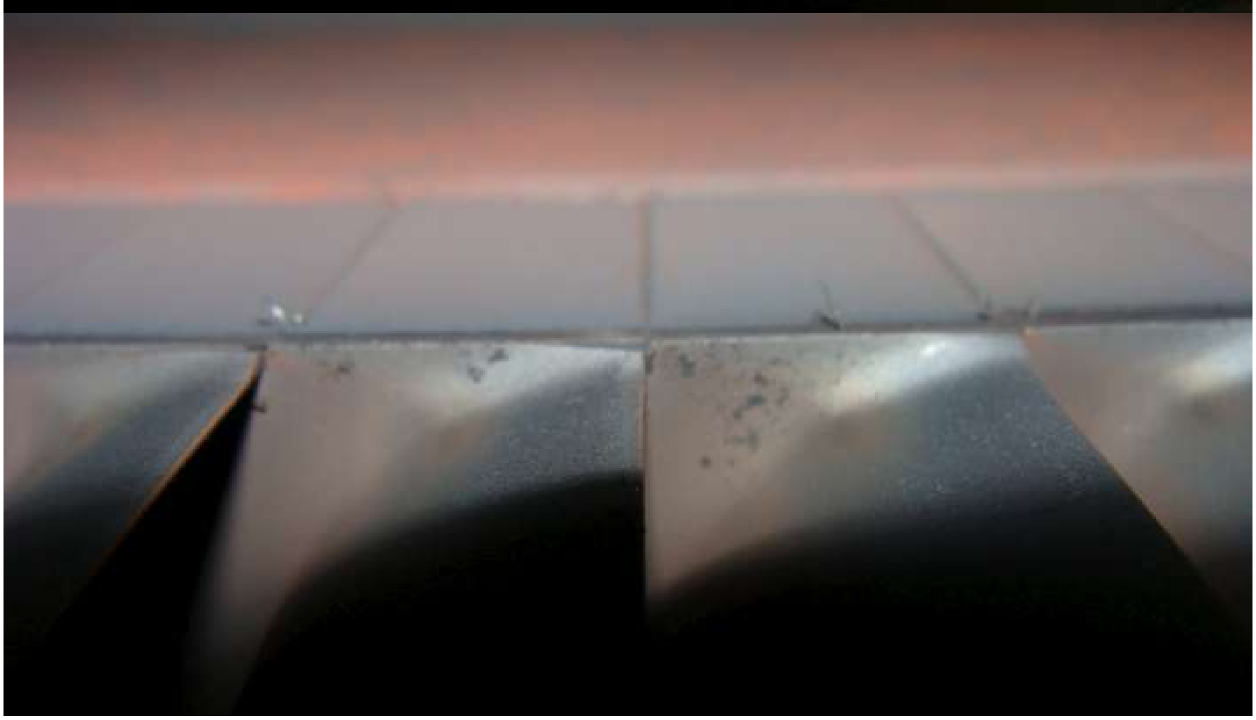
Row 7 blade root rub



Row 8 cover and tenon condition

Row 8 blade inlet condition





Row 8 blade root rub

Row 9 cover and tenon condition

Row 9 blade inlet condition

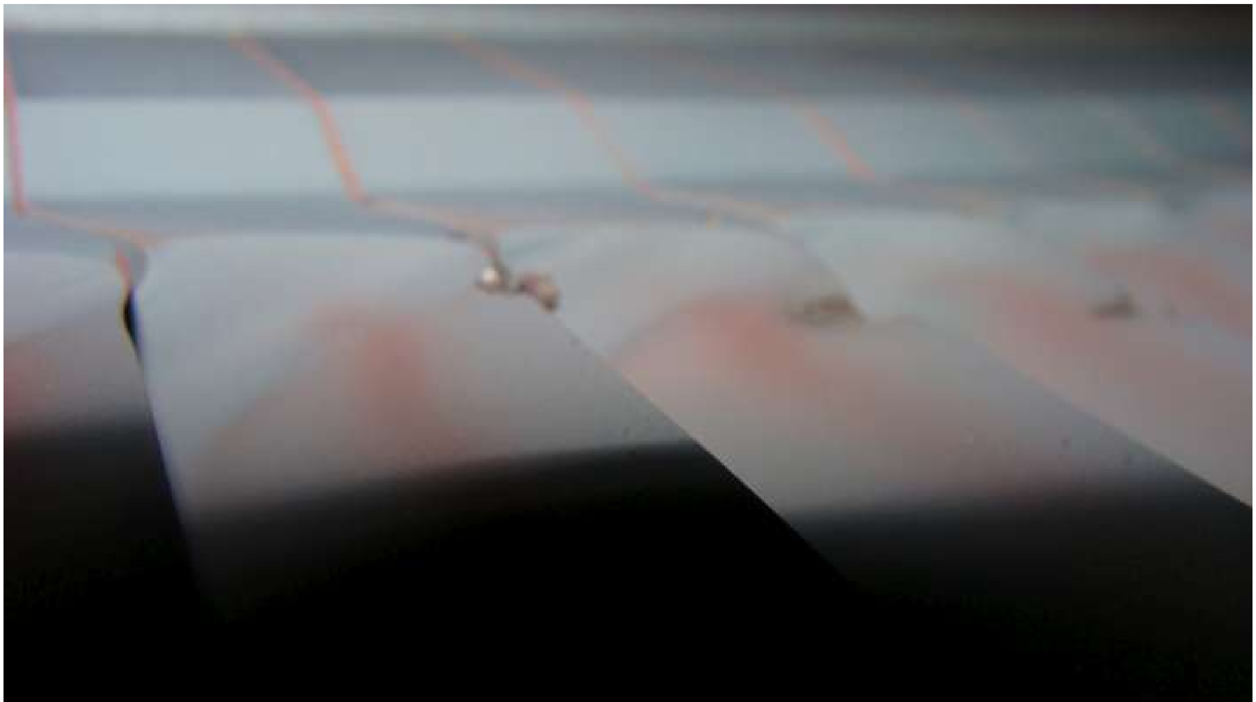
Row 11 general condition

Row 11 cover condition

Row 11 cover

Row 11 cover

Row 11 FOD at trailing edge of blades



Row 12 cover

Row 13 cover

Row 13 cover and tenon

Row 14 cover

Row 14 cover and tenon

Row 14 cover

Row 15 cover

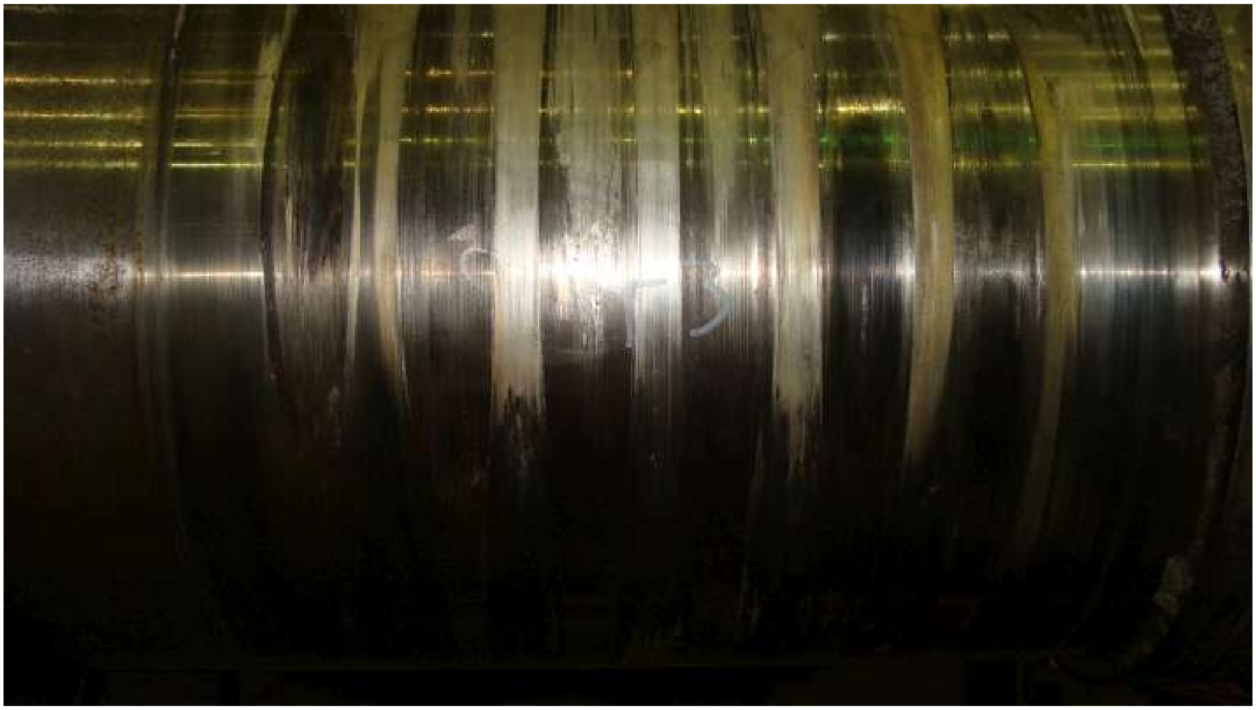
Row 16 cover

Row 17 cover rub, tenon rub

Row 17 cover rub

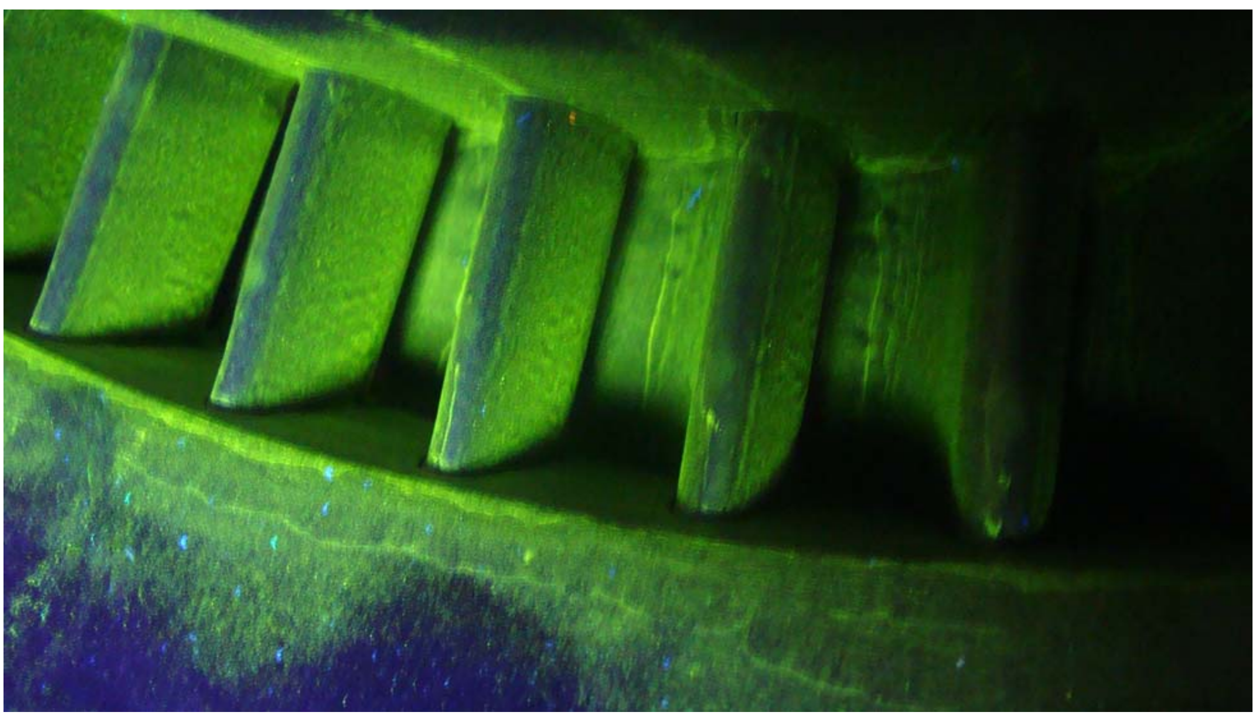
T1 journal

T1 oil deflector location and T2 journal



T3 journal

During the NDE lines were found on the Stage 2 and Stage 3 diaphragm blades. These lines were caused by previous weld repairs.



Generator:

The generator stator and bushing box were hand cleaned removing oil and film.

Run outs were performed on the generator found to be acceptable. While in the lathe, the collector rings were polished. A clean up cut was taken on the grounding brush journal.

The Hydrogen coolers were pressure tested and no leaks were found.

Hardness checks were performed on the generator journals and found to be acceptable. Refer to Team Inc. NDE report for results.

The generator lube oil supply and return piping was removed and hand cleaned to remove babbit and debris.

Refer to separate reports from bump test technician and generator specialist.

The rotor and diaphragms were grit blasted and NDE was performed. The nozzle blocks were not grit blasted, but NDE was performed.

Turbine and Generator Run Outs:

The generator runs were recorded and found to acceptable. The turbine rotor runouts indicated out of round bearing journals, and also a slight bend at the front end of the HP turbine rotor. Based on the runo out data, it will be necessary to perform the following in order to have the turbine rotor run true to the center of the rotor:

- Skim cut oil deflector /gland journals to make run outs 0. Remove minimum material
- Install lathe bearings at oil deflector/gland journals
- Machine journals to round
- Install Jack shaft at coupling inside of spigot to remove drive plate. (will make locally out of pipe and flanges)
- Check run out of spigot and coupling face
- Peen and machine spigot as necessary (bladers to perform peening)
- Skim cut coupling rim and face as necessary to run true to the journal
- Skim cut thrust runner and extension shaft as necessary
- Hone coupling holes, if necessary
- If it is necessary to hone/line bore coupling holes, new coupling bolts may need to be installed.

Recommendations for Repairs

Section	Component	Recommendation	Option 1 Safe	Option 2 Efficiency	Option 3 Both
Generator	Collector rings	Skim cut to true and polish	X	X	X
	T5 Outer Oil Deflector	Re-tooth and machine to specified diameter following generator rotor clean-up	X	X	X
	T5 Bearing	Install new Bearing or repair bearing removed from service	X	X	X
	CE H2 Seal Casing	Replace / repair gas side oil deflector	X	X	X
		Send H2 Seal casing to vendor for inspection and machining of hook fits and true joints	X	X	X
		H2 Seals	X	X	X
	T5 Inner Oil Deflector	Re-tooth and machine to specified diameter following generator rotor clean-up	X	X	X
	T5 Journal and H2 Seal Area	Strap journal and seal area	X	X	X
	T4 Inner Oil Deflector	Re-tooth and machine to specified diameter following generator rotor clean-up	X	X	X
	TE H2 Seal Casing	Replace / repair gas side oil deflector	X	X	X
		Send H2 Seal casing to vendor for inspection and machining of hook fits and true joints	X	X	X
		H2 Seals	X	X	X
	T4 Bearing	Install new Bearing or repair bearing removed from service	X	X	X
	T4 Outer Oil Deflector	Re-tooth and machine to specified diameter following generator rotor clean-up	X	X	X
	T4 Journal and H2 Seal Area	Strap journal and seal area	X	X	X
	Shaft grounding Brush Area	Machine and polish to remove grooving and provide better grounding contact area	X	X	X
LP Steam Turbine Stationary	T3 outer oil deflector	Replace insert teeth and machine to specified bore diameters once rotor surfaces are cleaned	X	X	X
	Coupling Guard	Clean up rubbed areas in bore. Drill out and re-tap support block bolting. Install all new bolting and locks	X	X	X

	T3 Bearing	Install replacement bearing. Replacement bearing may need to have the bore built up and re-machined to new journal diameter plus clearance. Replacement bearings will need to be drilled for vibration probes (upper half). May need new bolt on oil seals for replacement bearing if they do not have.	X	X	X
	T3 Inner Oil Deflector	Replace with new oil deflector. Machine bore to specified diameter following rotor clean up	X	X	X
	N5 Gland Packing	Replace all N5 Gland Packing segments, springs and retainers. Rings 46, 47, 48	X	X	X
	LPGE Stg 5	Replace Diaphragm Packing Ring R45		X	
		Sharpen packing segments	X		
		Replace Radial Spill Strip and machine diameter		X	
		Straighten / Grind existing Radial Spill Strip	X		
	LPGE Stg 4	Replace Diaphragm Packing Ring R44		X	
		Sharpen packing segments	X		
		Replace Radial Spill Strip and machine diameter		X	
		Straighten / Grind existing Radial Spill Strip	X		
LP Steam Turbine Stationary	LPGE Stg 3	Replace Diaphragm Packing Ring R43		X	
		Sharpen packing segments	X		
		Replace Radial Spill Strip and machine diameter		X	
		Straighten / Grind existing Radial Spill Strip	X		
	LPGE Stg 2	Replace Diaphragm Packing Ring R42		X	
		Sharpen packing segments	X		
		Replace Radial Spill Strip		X	
		Straighten / Grind existing Radial Spill Strip	X		
	LPGE Stg 1	Replace Radial Spill Strip and machine diameter		X	
		Straighten / Grind existing Radial Spill Strip	X		
	LP Double Flow	Replace steam packing Ring 41		X	
	LPTE Stg 1	Replace Radial Spill Strip and machine diameter		X	
		Straighten / Grind existing Radial Spill Strip	X		
	LPTE Stg 2	Replace Diaphragm Packing Ring R40		X	
		Sharpen packing segments	X		
		Replace Radial Spill Strip and machine diameter		X	
		Straighten / Grind existing Radial Spill Strip	X		

	LPTE Stg 3	Replace Diaphragm Packing Ring R39		X	
		Sharpen packing segments	X		
		Replace Radial Spill Strip and machine diameter		X	
		Straighten / Grind existing Radial Spill Strip	X		
	LPTE Stg 4	Replace Diaphragm Packing Ring R38		X	
		Sharpen packing segments	X		
		Replace Radial Spill Strip and machine diameter		X	
		Straighten / Grind existing Radial Spill Strip	X		
	LPTE Stg 5	Replace Diaphragm Packing Ring R37		X	
		Sharpen packing segments	X		
		Replace Radial Spill Strip and machine diameter		X	
		Straighten / Grind existing Radial Spill Strip	X		
	N4 Packing Gland	Replace all N5 Gland Packing segments, springs and retainers. Rings 34, 35, 36	X	X	X
IP Steam Turbine Stationary	T2 GE Oil Deflector	Replace with new oil deflector. Final bore to be machined following rotor clean up	X	X	X
	T2 Bearing	Replace Bearing with spare. Bore may need to be built up and machined following cleanup of rotor journal. Upper half will need to be drilled for vibration probes. May need new bolt on oil seals if the spare bearing does not have.	X	X	X
	T2 TE Oil Deflector	Replace with new oil deflector. Final bore to be machined following rotor clean up	X	X	X
	N3 packing	Replace all N3 Packing segments, springs and retainers. Rings 29, 30, 31, 32	X	X	X
	IP Row 17	Replace R28 Packing		X	
		Sharpen packing segments	X		
		Replace Radial Spill Strip and machine diameter		X	
		Straighten / Grind existing spill strip	X		
	IP Row 16	Replace R27 Packing		X	
		Sharpen packing segments	X		
		Replace Radial Spill Strip and machine diameter		X	
		Straighten / Grind existing spill strip	X		
	IP Row 15	Replace R26 Packing		X	
		Sharpen packing segments	X		
		Replace Radial Spill Strip and machine diameter		X	

		Straighten / Grind existing spill strip	X		
	IP Row 14	Replace R25 Packing		X	
		Sharpen packing segments	X		
		Replace Radial Spill Strip and machine diameter		X	
		Straighten / Grind existing spill strip	X		
	IP Row 13	Replace R24 Packing		X	
		Sharpen packing segments	X		
		Replace Radial Spill Strip and machine diameter		X	
		Straighten / Grind existing spill strip	X		
	IP Row 12	Replace R23 Packing		X	
		Sharpen packing segments	X		
		Replace Radial Spill Strip and machine diameter		X	
		Straighten / Grind existing spill strip	X		
IP Steam Turbine Stationary	IP Row 11	Replace R22 Packing		X	
		Sharpen packing segments	X		
		Replace Radial Spill Strip and machine diameter		X	
		Straighten / Grind existing spill strip	X		
HP Steam Turbine Stationary	N2 Packing Gland	Replace all packing, springs and retainers in the N2 packing gland. Rings 16, 17, 18, 19, 20, 21		X	
	Inlet Nozzle	Weld Repair and Machine Integral Spill Strip		X	
		Straighten / Grind existing integral spill strip	X		
	Stg 2 Diaphragm	Replace Diaphragm packing springs and spring retainer. Ring 15		X	
		Straighten and sharpen packing	X		
		Replace Radial spill Strip and machine diameter		X	
		Hand work / grind the radial spill strip to clean up	X		
		Weld repair and machine outer and inner setback faces to remove grooving		X	
		Handwork to remove any rolled over metal and weld repairs to partitions as required	X	X	X
	Stg 3 Diaphragm	Replace Diaphragm packing springs and spring retainer. Ring 14		X	
		Straighten and sharpen packing	X		
		Replace Radial spill Strip and machine diameter		X	
		Hand work / grind the radial spill strip to	X		

		clean up			
		Weld repair and machine outer and inner setback faces to remove grooving		X	
		Handwork to remove any rolled over metal and weld repairs to partitions as required	X	X	X
	Stg 4 Diaphragm	Replace Diaphragm packing springs and spring retainer. Ring 13		X	
		Straighten and sharpen packing	X		
		Replace Radial spill Strip and machine diameter		X	
		Hand work / grind the radial spill strip to clean up	X		
		Weld repair and machine outer and inner setback faces to remove grooving		X	
		Handwork to remove any rolled over metal and weld repairs to partitions as required	X	X	X
	Stg 5 Diaphragm	Replace Diaphragm packing springs and spring retainer. Ring 12		X	
		Straighten and sharpen packing	X		
		Replace Radial spill Strip and machine diameter		X	
		Hand work / grind the radial spill strip to clean up	X		
		Weld repair and machine outer and inner setback faces to remove grooving		X	
		Handwork to remove any rolled over metal and weld repairs to partitions as required	X	X	X
	Stg 6 Diaphragm	Replace Diaphragm packing springs and spring retainer. Ring 11		X	
		Straighten and sharpen packing	X		
		Replace Radial spill Strip and machine diameter		X	
		Hand work / grind the radial spill strip to clean up	X		
		Weld repair and machine outer and inner setback faces to remove grooving.		X	
		Handwork to remove any rolled over metal and weld repairs to partitions as required	X	X	X
	Stg 7 Diaphragm	Replace Diaphragm packing springs and spring retainer. Ring 10		X	
		Straighten and sharpen packing	X		
		Replace Radial spill Strip and machine diameter		X	
		Hand work / grind the radial spill strip to	X		

		clean up			
		Weld repair and machine outer and inner setback faces to remove grooving		X	
		Handwork to remove any rolled over metal and weld repairs to partitions as required	X	X	X
	Stg 8 Diaphragm	Replace Diaphragm packing springs and spring retainer. Ring 9		X	
		Straighten and sharpen packing	X		
		Replace Radial spill Strip		X	
		Hand work / grind the radial spill strip to clean up	X		
		Weld repair and machine outer and inner setback faces to remove grooving		X	
		Handwork to remove any rolled over metal and weld repairs to partitions as required	X	X	X
	Stg 9 Diaphragm	Replace Diaphragm packing springs and spring retainer. Ring 8		X	
		Straighten and sharpen packing	X		
		Replace Radial spill Strip and machine diameter		X	
		Hand work / grind the radial spill strip to clean up	X		
		Weld repair and machine outer and inner setback faces to remove grooving		X	
		Handwork to remove any rolled over metal and weld repairs to partitions as required	X	X	X
	N1 Packing Gland	Replace all packing segments, springs and retainers in the N1 gland. Rings 1, 2, 3, 4, 5, 6, 7	X	X	X
	T1 outer oil Deflector	Replace with new oil deflector. Final bore to be machined following rotor clean up	X	X	X
	T1 Bearing	Replace the Bearing and liner with spare from customer stock. The liner may require buildup of the bore and final machining once the T1 journal is cleaned up. Will need to be drilled for vibration probes. May need new bolt on oil seal if new bearing does not have one.	X	X	X
	Thrust Bearing	Install new Active and Inactive tapered land copper back thrust plates. Drill for TC's.	X	X	X
		Replace oil seal in the Thrust cage	X	X	X
		Replace Bronze seal ring in thrust cage	X	X	X
	60 tooth wheel	Replace 60 tooth wheel or repair the existing 60 tooth wheel.	X	X	X

Steam Turbine Rotor HP Section	Thrust Runner	Hardness check on the rear face. Polish (only) the rear face	X	X	X
	T1 Journal	Cleanup journal, hardness check, machine as needed	X	X	X
	T1 oil deflector journal	Cleanup to remove grooving and adhered material from the oil deflector	X	X	X
	Stg 9	Machine cover to remove rolled over material and true up	X	X	X
		Machine to clean up root appendage	X	X	X
		Replace row 9 bucket covers to re-establish axial clearance. Covers will have to be removed, Tenons nde'd, new fox holed covers installed and peened, covers machined for diameter, profile and axial clearance		X	
	Stg 8	Machine cover to remove rolled over material and true up	X	X	X
		Machine to clean up root appendage	X	X	X
		Replace row 8 bucket covers to re-establish axial clearance. Covers will have to be removed, Tenons nde'd, new fox holed covers installed and peened, covers machined for diameter, profile and axial clearance		X	
	Stg 7	Machine cover to remove rolled over material and true up	X	X	X
		Machine to clean up root appendage	X	X	X
		Replace row 7 bucket covers to re-establish axial clearance. Covers will have to be removed, Tenons nde'd, new fox holed covers installed and peened, covers machined for diameter, profile and axial clearance		X	
	Stg 6	Machine cover to remove rolled over material and true up	X	X	X
		Machine to clean up root appendage	X	X	X
		Replace row 6 bucket covers to re-establish axial clearance. Covers will have to be removed, Tenons nde'd, new fox holed covers installed and peened, covers machined for diameter, profile and axial clearance		X	
	Stg 5	Machine cover to remove rolled over material and true up	X	X	X

		Machine to clean up root appendage	X	X	X
		Replace row 5 bucket covers to re-establish axial clearance. Covers will have to be removed, Tenons nde'd, new fox holed covers installed and peened, covers machined for diameter, profile and axial clearance		X	
	Stg 4	Machine cover to remove rolled over material and true up	X	X	X
		Machine to clean up root appendage	X	X	X
		Replace row 4 bucket covers to re-establish axial clearance. Covers will have to be removed, Tenons nde'd, new fox holed covers installed and peened, covers machined for diameter, profile and axial clearance		X	
	Stg 3	Re-peen covers that have slight lifting, machine covers to remove rolled over material and true up	X	X	X
		Machine to clean up root appendage	X	X	X
		Replace row 3 bucket covers to re-establish axial clearance. Covers will have to be removed, Tenons nde'd, new fox holed covers installed and peened, covers machined for diameter, profile and axial clearance		X	
	Stg 2	Remove damaged covers, clean up tenons, install new fox holed covers, re-peen covers that show minor lifting, machine covers for diameter, profile and cleanup	X	X	X
		Machine to clean up root appendage	X	X	X
		Replace row 2 bucket covers to re-establish axial clearance. Covers will have to be removed, Tenons nde'd, new fox holed covers installed and peened, covers machined for diameter, profile and axial clearance		X	
	Stg 1	Re-peen row 1 covers as required to remove cover lifting. If necessary, replace row 1 covers	X	X	X
		Machine cover to remove rolled over material and true up	X	X	X
		Machine and handwork Stage 1 buckets to clean up integral cover	X	X	
		Machine to clean up root appendage	X	X	X

Steam Turbine Rotor IP Section	Stage 11	Machine covers to remove rolled over material and establish profile	X	X	X
	Stage 12	Machine covers to remove rolled over material and establish profile	X	X	X
	Stage 13	Machine covers to remove rolled over material and establish profile	X	X	X
	Stage 14	Machine covers to remove rolled over material and establish profile	X	X	X
	Stage 15	Machine covers to remove rolled over material and establish profile	X	X	X
	Stage 16	Machine covers to remove rolled over material and establish profile	X	X	X
	Stage 17	Machine covers to remove rolled over material and establish profile	X	X	X
	T2 TE oil deflector journal	Cleanup to remove grooving and adhered material from the oil deflector	X	X	X
	T2 journal	Cleanup journal, hardness check, machine as needed	X	X	X
	T2 GE oil deflector journal	Cleanup to remove grooving and adhered material from the oil deflector	X	X	X
Steam Turbine Rotor LP Section	Stg 5 TE	Clean up bucket covers to remove any rolled over material	X	X	X
	Stg 4 TE	Clean up bucket covers to remove any rolled over material	X	X	X
	Stg 3 TE	Clean up bucket covers to remove any rolled over material	X	X	X
	Stg 2 TE	Clean up bucket covers to remove any rolled over material	X	X	X
	Stg 1 TE	Clean up bucket covers to remove any rolled over material	X	X	X
	Stg 1 GE	Clean up bucket covers to remove any rolled over material	X	X	X
	Stg 2 GE	Clean up bucket covers to remove any rolled over material	X	X	X
	Stg 3 GE	Clean up bucket covers to remove any rolled over material	X	X	X
	Stg 4 GE	Clean up bucket covers to remove any rolled over material	X	X	X
	Stg 5 GE	Clean up bucket covers to remove any rolled over material	X	X	X
	T3 Inner oil deflector journal	Cleanup to remove grooving and adhered material from the oil deflector	X	X	X

	T3 Journal	Cleanup journal, hardness check, machine as needed	X	X	X
	T3 Outer oil deflector Journal	Cleanup to remove grooving and adhered material from the oil deflector	X	X	X

TEAM® Industrial Services
TISI Canada Inc.

ISO 9001:2008

ULTRASONIC EXAMINATION REPORT

Job Number: 52081083	Client Specifications: QA/QC
Client Name/Address: NL Hydro	Acceptance: ASME V
Date/Time: 11 Feb 2013	Procedure: UT.ASME. 3 Rev: 8
Work Location/Address: Holyrood, NL	Technique: Longitudinal
Part Description: Horizontal Joint Studs	P.O. Number: 19101OB

Type of Fabrication: **Weld [ ]** **Casting [ ]** **Forging [ ]** **Plate [ ]** **Other [x]**

Part/Assy No.:	**Dwg No.:**	**Heat No.:**	**Pattern No.:**
N/A	N/A	N/A	N/A

Scope: **Unit 1 – Turbine**

Ultrasonic Inspection to be carried out on Unit 1 Turbine- Horizontal Joint Studs.

Results:

An Ultrasonic Inspection was carried out as per scope in accordance with acceptance and procedure.

No relevant indications were found in accordance with code.

Total Parts Inspected	Total Parts Accepted	Total Parts Rejected
-	-	0

Scan: Longitudinal/ Zero Degree

Surface Finish: Smooth

ULTRASONIC EQUIPMENT				**TRANSDUCER**			
Make	**Model**	**S/N**	**Cal. Date**	**Angle**	**Size**	**Frequency**	**S/N**
Olympus	Epoch 600	110066601	Dec 2012	0 Deg	0.500	5.0 Mhz	018370

Calibration Block: IIW Block Type 1	**Serial No.:** 3175
Couplant: Exosen 30	**Batch No.:** 29110301

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TEAM TECHNICIAN: Print Name **Terry Oliver** Signature	**Certification:** **11416** ACCP Level II [ ] CGSB 48.9712 Level 2 [x] SNT-TC-1A Level II [ ]
CLIENT REPRESENTATIVE FINAL ACCEPTANCE: Print Name	Signature Date

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MAGNETIC PARTICLE EXAMINATION REPORT

ISO 9001:2008

Branch Office: 41 Sagona Ave, Mount Pearl, NL A1N 4P9 Tel. (709) 745-1818 * Fax (709)745-5401

Job Number: 52081083	Client Specifications: CLIENT QA/QC
Client Name: NF HYDRO / ALSTOM	Acceptance: ASME VIII
Date Of Examination: Feb. 13th, 2013	Procedure: MT ASME 2 REV 1
Work Location: Holyrood, NL	Technique: ASME V
	P.O. Number: 19101 OB

Type of Fabrication: **Weld** **Casting** **Forging X** **Plate** **Other**

Part/Assy No.:	Dwg No.:		Pattern No.:
N/A	N/A	N/A	N/A

Scope:
This report covers the magnetic particle inspection of Unit #1 Generator Rotor – journals and coupling as requested by Alstom.

Results: At the time of inspection no rejectable indications were noted. The above work is acceptable to code.

Total Parts Inspected	Total Parts Accepted	Total Parts Rejected
3	3	0

Magnetizing Equipment			**Inspection Medium**		**Demagnetize**	
Equipment	Current	Serial No.	Product	Batch No.	Yes	No X
Yoke	A/C	2606	7HF	10M05K		
			WCP-2	10M02K	No. of Oersteds	
Additional Equipment Used:					**N/A**	
Flashlight						

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TEAM TECHNICIAN: Print Name **Cyril Pretty**	Signature: Pretty	**Certification: 4353** ACCP Level II ☐ CGSB 48.9712 Level II ✓ SNT-TC-1A Level II
CLIENT REPRESENTATIVE FINAL ACCEPTANCE: Print Name **Mike Flynn**	Signature	Date

ISO 9001:2008

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ULTRASONIC EXAMINATION REPORT

Job Number: 52081083	Client Specifications: Client QA/QC
Client Name/Address: NF Hydro / Alstom	Acceptance: ASME VIII
Date/Time: Feb 12th, 2013	Procedure: UT ASME 4 Rev 0
Work Location/Address: Mt Pearl, NL	Technique: ASME V
Part Description: Bearings	P.O. Number: 19101OB

Type of Fabrication: **Weld []** **Casting [ ]** **Forging []** **Plate [ ]** **Other [✓]**

Part/Assy No.:	Dwg No.:	Heat No.:	Pattern No.:
N/A	N/A	N/A	N/A

Scope: This report covers the ultrasonic inspection of the following bearing babbitt for Unit # 1 Turbine:
Bearings # 1, 2, 3, 4 & 5.
Thrust bearings.

Results:
An ultrasonic straight beam examination was carried out in accordance with acceptance and procedure, no lack of bond between the Babbitt and the backing material was noted.

Total Parts Inspected	Total Parts Accepted	Total Parts Rejected
N/A	N/A	N/A

Scan: Longitudinal

Surface Finish: Smooth

ULTRASONIC EQUIPMENT				**TRANSDUCER**			
Make	**Model**	**S/N**	**Cal. Date**	**Angle**	**Size**	**Frequency**	**S/N**
Olympus	Epoch 600	110066601	Dec 2012	0	0.500"	2.25 MHz	802524

Calibration Block: IIW Type I Sample Material	**Serial No.:** 3175
Couplant: Exosen 30	**Batch No.:** 29110301

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TEAM TECHNICIAN: Print Name **Cyril Pretty** Signature *C Pretty*	**Certification: 4353** ACCP Level II [ ] CGSB 48.9712 Level 1 [✓] SNT-TC-1A Level II [ ]
CLIENT REPRESENTATIVE FINAL ACCEPTANCE: Print Name	Signature Date

CGSB Level II Reg #135

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MAGNETIC PARTICLE EXAMINATION REPORT

Job Number: 5208 1083	Client Specifications: QA/QC
Client Name/Address: NL Hydro/Alstom	Acceptance: ASME Section VIII
Date Of Examination: 2013/Feb/15 – 2013/Feb/17	Procedure: MT.ASME.1 Rev. 15
Work Location/Address: Holyrood, NL	Technique: ASME V
Part Description: Unit #1 Turbine Rotor Fan Blades	P.O. Number: 19101OB

Type of Fabrication: **Weld [X]** **Casting [ ]** **Forging [ ]** **Plate [ ]** **Other [ ]**

Part/Assy No.:	Dwg No.:	Heat No.:	Pattern No.:
n/a	n/a	n/a	n/a

Scope:

As requested by the client, a fluorescent magnetic particle examination is to be performed on 100 % of all fan blades and gear on the Unit # 1 turbine rotor.

Results:

Wet fluorescent magnetic particle was carried out as per scope in accordance with acceptance and procedure. At the time of inspection, no indications were found and all areas are acceptable to code.

Note: Blades on the HP section have moderate to heavy pitting throughout

Total Parts Inspected	Total Parts Accepted	Total Parts Rejected
-	-	-
Min black light intensity is 1000 microwatts: @ 15" from the surface of the part. **Y** [ ] **N** [ ] @ surface **OK** [ ] mw/cm2: [ ] NA	*** Document black and white light meters S/N and calibration dates:**	Minimum white light intensity is 100 ft. candles at the surface of the part. **OK** [ ] Ft candles:[ ]

Magnetizing Equipment			**Inspection Medium**		**Demagnetize**	
Equipment	Current	Serial No.	Product	Batch No.	Yes	No x
Magwerks	A/C	080521	Lumor J	4207		
Blacklight		16476			No. of Oersteds	
Magnetic Penetrameter		84261				
Additional Equipment Used (Incl lighting equipment details):						

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TEAM TECHNICIAN: K. Jacobs / R. Lilly (Print Name) — Signature	**Certification: 13562 /11108** ACCP Level II [ ] CGSB 48.9712 Level 2 [X] SNT-TC-1A Level II [ ]
CLIENT REPRESENTATIVE FINAL ACCEPTANCE:	Print Name — Signature — Date

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MAGNETIC PARTICLE EXAMINATION REPORT

Job Number: 5208 1083	Client Specifications: QA/QC
Client Name/Address: NL Hydro/Alstom	Acceptance: ASME Section VIII
Date Of Examination: 2013/Feb/15 – 2013/Feb/17	Procedure: MT.ASME.1 Rev. 15
Work Location/Address: Holyrood, NL	Technique: ASME V
Part Description: Unit #1 Turbine Diaphragms	P.O. Number: 19101OB

Type of Fabrication: **Weld [X]** **Casting [ ]** **Forging [ ]** **Plate [ ]** **Other [ ]**

Part/Assy No.:	**Dwg No.:**	**Heat No.:**	**Pattern No.:**
n/a	n/a	n/a	n/a

Scope:

As requested by the client, a fluorescent magnetic particle examination is to be performed on 100 % of all Unit #1 diaphragms.

Results:

Wet fluorescent magnetic particle was carried out as per scope in accordance with acceptance and procedure. Transverse linear indications noted on #2 and #3 Top and Bottom from pass repairs.
Diaphragm #4 TOP - 2 damaged blades as well as damaged outside web.

NOTE-PITTING ON ALL BLADES .

Total Parts Inspected	Total Parts Accepted	Total Parts Rejected
-	-	#2Top/Bottom #3 Top/Bottom and #4 Top only
Min black light intensity is 1000 microwatts: @ 15" from the surface of the part. **Y** [x] **N** [ ] @ surface **OK** [x] mw/cm2: [ ] 1250 microwatts	*** Document black and white light meters S/N and calibration dates: Spectroline DM-365X** Ser#411419 Feb.21/2013	Minimum white light intensity is 100 ft. candles at the surface of the part. **OK** [X] Ft candles:[67]

Magnetizing Equipment			**Inspection Medium**		**Demagnetize**	
Equipment	Current	Serial No.	Product	Batch No.	Yes	No x
Magwerks	A/C	080521	Lumor J	4207		
Blacklight		16476			No. of Oersteds	
Magnetic Penetrameter		84261				
Additional Equipment Used **(Incl lighting equipment details):**						

TEAM TECHNICIAN: Print Name R. Lilly	Signature Richard Lilly	**Certification: 11108** ACCP Level II [ ] CGSB 48.9712 Level 2 [X] SNT-TC-1A Level II [X]
CLIENT REPRESENTATIVE FINAL ACCEPTANCE:	Print Name	Signature Date

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MAGNETIC PARTICLE EXAMINATION REPORT

Job Number: 5208 1083	Client Specifications: QA/QC
Client Name/Address: NL Hydro/Alstom	Acceptance: ASME Section VIII
Date Of Examination: 2013/Feb/15 – 2013/Feb/17	Procedure: MT.ASME.1 Rev. 15
Work Location/Address: Holyrood, NL	Technique: ASME V
Part Description: Unit #1 Turbine Rotor Fan Blades	P.O. Number: 19101OB

Type of Fabrication: **Weld [X]** **Casting [ ]** **Forging [ ]** **Plate [ ]** **Other [ ]**

Part/Assy No.:	Dwg No.:	Heat No.:	Pattern No.:
n/a	n/a	n/a	n/a

Scope:

As requested by the client, a fluorescent magnetic particle examination is to be performed on 100 % of all fan blades and gear on the Unit # 1 turbine rotor.

Results:

Wet fluorescent magnetic particle was carried out as per scope in accordance with acceptance and procedure. At the time of inspection, no indications were found and all areas are acceptable to code.

Note: Blades on the HP section have moderate to heavy pitting throughout

Total Parts Inspected	Total Parts Accepted	Total Parts Rejected
-	-	-
Min black light intensity is 1000 microwatts: @ 15" from the surface of the part. **Y** [ ] **N** [ ] @ surface **OK** [ ] mw/cm2: [ ] NA	*** Document black and white light meters S/N and calibration dates:**	Minimum white light intensity is 100 ft. candles at the surface of the part. **OK** [ ] Ft candles:[ ]

Magnetizing Equipment			**Inspection Medium**		**Demagnetize**	
Equipment	Current	Serial No.	Product	Batch No.	Yes	No x
Magwerks	A/C	080521	Lumor J	4207		
Blacklight		16476			No. of Oersteds	
Magnetic Penetrameter		84261				
Additional Equipment Used (Incl lighting equipment details):						

TEAM TECHNICIAN: Print Name K. Jacobs / R. Lilly Signature Richard Lilly	**Certification: 13562 /11108** ACCP Level II [ ] CGSB 48.9712 Level 2 [X] SNT-TC-1A Level II [ ]
CLIENT REPRESENTATIVE FINAL ACCEPTANCE: Print Name	Signature Date

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MAGNETIC PARTICLE EXAMINATION REPORT

Job Number: 52081083	Client Specifications: QA/QC
Client Name/Address: NL Hydro	Acceptance: ASME SECTION VIII
Date Of Examination: Feb 26, 2013	Procedure: MT ASME 1
Work Location/Address: Holyrood, NL	Technique: ASME V
Part Description: HP Nozzle block.	P.O. Number: 19101 OB

Type of Fabrication: **Weld [ ]** **Casting [ ]** **Forging [ ]** **Plate [ ]** **Other [X]**

Part/Assy No.:	Dwg No.:	Heat No.:	Pattern No.:
N/A	N/A	N/A	N/A

Scope: To perform a fluorescent magnetic particle inspection on unit 1 Turbine HP nozzle block.

.

Results: As requested by Alstom 100% of the upper and lower HP nozzle block was inspected using the wet fluorescent method of MPI .At the time of inspection no indications were found all areas are acceptable to code.

Total Parts Inspected	Total Parts Accepted	Total Parts Rejected
2	2	0
Min black light intensity is 1000 microwatts: @ 15" from the surface of the part. **Y** [x] **N** [ ] @ surface **OK** [x] mw/cm2: [x]	*** Document black and white light meters S/N and calibration dates:**	Minimum white light intensity is 100 ft candles at the surface of the part. **OK** [x] Ft candles:[ ]

Magnetizing Equipment			**Inspection Medium**		**Demagnetize**	
Equipment	Current	Serial No	Product	Batch No.	Yes	No x
Parker Probe	A/C	16267	Lumor J	4207		
					No. of Oersteds	
Additional Equipment Used Incl lighting equipment details): Black Light Serial No. **16476**					**N/A**	

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TEAM TECHNICIAN: Print Name: Glenn Melindy Signature:	**Certification:** **10096** ACCP Level II [ ] CGSB 48.9712 Level 2 [x] SNT-TC-1A Level II [ ]
CLIENT REPRESENTATIVE FINAL ACCEPTANCE: Print Name	Signature Date

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Industrial Services
Inspection Services Canada

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VICKERS HARDNESS TESTING

DATE: Feb 26, 2013

UNIT No 1 TURBINE # 4 BEARING JOURNAL					COMMENTS
LOCATION					
No 1	222	231	229	231	READINGS WERE TAKEN EVERY 90 DEG.
No 2	232	222	225	226	
No 3	236	226	223	236	
UNIT: MIC 10	S/N: 34103-5763				
PROCEDURE	HT-GP-01 REV. 1				

TEAM INDUSTRIAL SERVICES REPRESENTATIVE: Glenn Melindy

Industrial Services
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41 Sagona Ave. Mt. Pearl, NL A1N 4P9 PH: (709)745-1818 FX: (709)745-5401

VICKERS HARDNESS TESTING

DATE: Feb 26, 2013

UNIT No 1 TURBINE # 5 BEARING JOURNAL					**COMMENTS**
LOCATION					
No 1	**230**	**236**	**235**	**224**	**READINGS WERE TAKEN EVERY 90 DEG.**
No 2	**221**	**222**	**228**	**234**	
No 3	**239**	**229**	**233**	**227**	
UNIT: MIC 10	**S/N: 34103-5763**				
PROCEDURE	**HT-GP-01 REV. 1**				

TEAM INDUSTRIAL SERVICES REPRESENTATIVE: Glenn Melindy

ISO 9001:2008

Industrial Services
TISI Canada Inc.

MAGNETIC PARTICLE EXAMINATION REPORT

Job Number: 52081083	Client Specifications: QA/QC
Client Name/Address: NL HYDRO	Acceptance: W59
Date Of Examination: Jan 25, 2013	Procedure: MT ASME 1
Work Location/Address: Holyrood, NL	Technique: ASME V
Part Description: MT Turnbuckles	P.O. Number: 19101B

Type of Fabrication: **Weld [ ]** **Casting [ ]** **Forging [ ]** **Plate [ ]** **Other [x]**

Part/Assy No.:	Dwg No.:	Heat No.:	Pattern No.:
n/a	n/a	n/a	n/a

Scope: Magnetic Particle Examination to be carried out on Turbine / Generator lifting equipment: two turnbuckles, 4 clevis pins and two lifting arm, lifting frame assembly and eyebrow bracket and pins/seats as per **Work Assignment # 002.**

Results: A Magnetic particle Examination was carried out as per scope in accordance with acceptance and procedure. No defects were found at time of examination.

Total Parts Inspected	Total Parts Accepted	Total Parts Rejected
		0
Min black light intensity is 1000 microwatts: @ 15" from the surface of the part. Y [ ] N [ ] @ surface OK [ ] mw/cm2: [ ]	*** Document black and white light meters S/N and calibration dates:**	Minimum white light intensity is 100 ft candles at the surface of the part. **OK** [ ] Ft candles:[ ]

Magnetizing Equipment			**Inspection Medium**		**Demagnetize**	
Equipment	Current	Serial No.	Product	Batch No.	Yes	No x
Yoke	AC	2606	7HF	10M05K		
			WCP-2	12D07K	No. of Oersteds	
Additional Equipment Used **(Incl lighting equipment details):Flashlight**					**n/a**	

TEAM TECHNICIAN: Print Name: Chris Bishop	Signature:	**Certification:** CGSB 48.9712 Level 2 [x] ACCP Level II [ ] SNT-TC-1A Level II [x]
CLIENT REPRESENTATIVE FINAL ACCEPTANCE: Print Name	Signature	Date

Branch Office
41 Sagona Avenue, Mt. Pearl, NL A1N4P9
Telephone: (709) 745-1818 * Fax (709) 745-5401

011 MT R1

TEAM® Industrial Services
TISI Canada Inc.

ISO 9001:2008 IS

MAGNETIC PARTICLE EXAMINATION REPORT

Job Number: 5208 1083	Client Specifications: QA/QC
Client Name/Address: NL Hydro/Alstom	Acceptance: ASME Section VIII
Date Of Examination: 2013/Feb/15 – 2013/Feb/17	Procedure: MT.ASME.1 Rev. 15
Work Location/Address: Holyrood, NL	Technique: ASME V
Part Description: Unit #1 Turbine Rotor Fan Blades	P.O. Number: 19101OB

Type of Fabrication: **Weld [X]** **Casting [ ]** **Forging [ ]** **Plate [ ]** **Other [ ]**

Part/Assy No.:	**Dwg No.:**	**Heat No.:**	**Pattern No.:**
n/a	n/a	n/a	n/a

Scope:

As requested by the client, a fluorescent magnetic particle examination is to be performed on 100 % of all turbine blades and gear on the Unit # 1 turbine rotor.

Results:

Wet fluorescent magnetic particle was carried out as per scope in accordance with acceptance and procedure. At the time of inspection, no indications were found and all areas are acceptable to code.

Note: Blades on the HP section have moderate to heavy pitting throughout

Total Parts Inspected	Total Parts Accepted	Total Parts Rejected
-	-	-
Min black light intensity is 1000 microwatts: @ 15" from the surface of the part. **Y** [X] **N** [ ] @ surface **OK** [X] mw/cm2: [ ] NA	*** Document black and white light meters S/N and calibration dates: Spectroline DM-365X** Ser# 411419 2013/FEB/21	Minimum white light intensity is 100 ft. candles at the surface of the part. **OK** [X] Ft candles:[67]

Magnetizing Equipment			**Inspection Medium**		**Demagnetize**	
Equipment	Current	Serial No.	Product	Batch No.	Yes	No x
Magwerks	A/C	080521	Lumor J	4207		
Blacklight		16476			No. of Oersteds	
Magnetic Penetrameter		84261				
Additional Equipment Used **(Incl lighting equipment details):**						

This Certificate or Report is valid only for that work which was specifically requested. The Company is not responsible for any views or opinions expressed by employees performing this work which fall outside the exact terms of reference. All certificates and/or reports are the result of work performed in conformance with applicable specifications and standards to the best of our ability and intent. However, the company will not be responsible for deviations within the normal limits of accuracy in accordance with the standard practices. **Final Code acceptance shall require Client/Manufacture representative's signature.**

Print Name / Signature **TEAM TECHNICIAN:** Kristofer Jacobs	**Certification: 13562** ACCP Level II [ ] CGSB 48.9712 Level 2 [X] SNT-TC-1A Level II [ ]
CLIENT REPRESENTATIVE FINAL ACCEPTANCE:	Print Name / Signature / Date

Branch Office
41 Sagona Avenue, Mt. Pearl, NL A1N4P9
Telephone: (709) 745-1818 * Fax (709) 745-5401

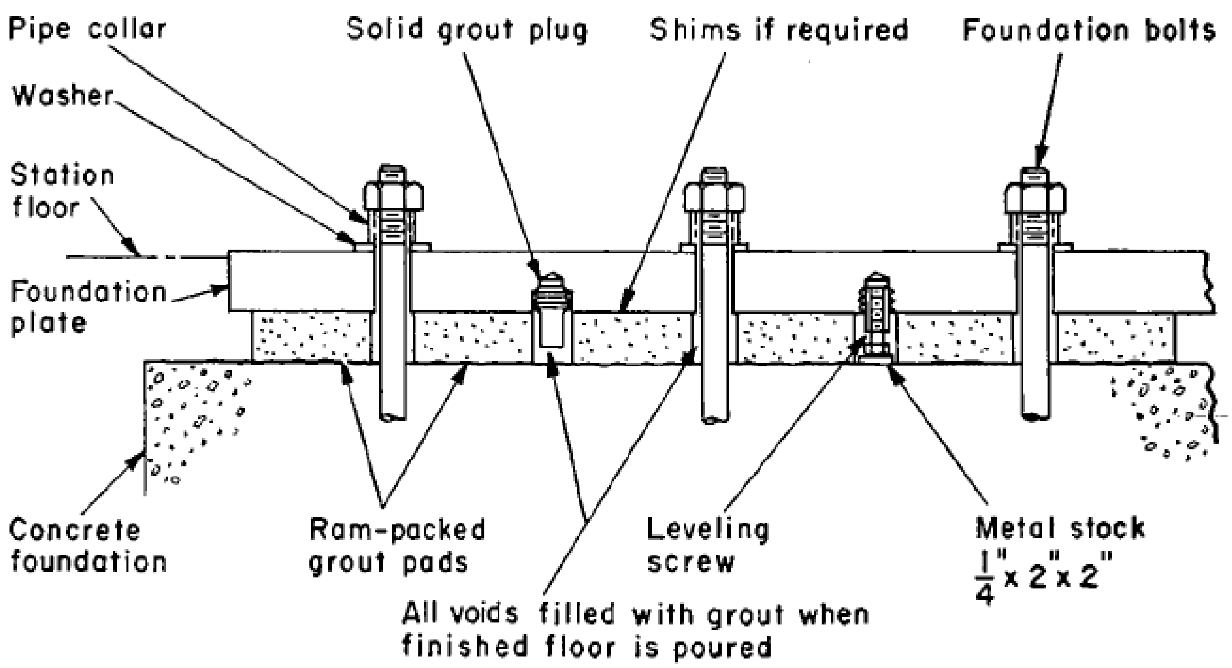
POWER ALSTOM	**STG INTERIM INSPECTION REPORT (IIR)**	**IIR # Gen006**
Subject: Generator Foundation Plate shim migration		Sheet 1/6 ISSUE #

Station: Holyrood	Unit #1	ALSTOM Conformity: Yes ☐ No ☐ Design Response Required: Yes ☐ No ☐ Design Accepted: Yes ☐ No ☐
Component Inspected: Casing ☐ Rotor ☐ HP ☐ IP ☐ LP1 ☐ LP2 ☐ LP3 ☐ Auxiliaries ☐ BFPT ☐ Stator ☒ Gen. Rotor ☐ Auxiliaries ☐ Exciter ☐ Valves ☐ MSR ☐ Controls ☐ Piping ☐ Component Serial Number:	Attachments; # PICTURES # RECORD SHEETS	
Contract # / Main Report #		CLIENT Client Accepts Recommendation: Yes ☐ No ☐ Client Accepts 'As Found': Yes ☐ No ☐
Programme Reference:		
Quality Plan Reference:		Signature: Date:

SITE INSPECTION

Report

Several of the shims under the foundation plate were found to have migrated. The thin vertical layer of grouting was found to be breaking up. The concrete foundation is considered to be in good condition.



Written By:	James George	Position: Technical Field Advisor	Date: 6/14/2012
Distribution For Action:	Client ☒	Engineering ☐	Project Manager ☐
Distribution For Information:	Client ☒	Engineering ☐	Project Manager ☐
CRN Reference no: (if applicable)			

POWER ALSTOM	**STG INTERIM INSPECTION REPORT (IIR)**	**IIR # Gen006**
Subject: Generator Foundation Plate shim migration		Sheet 2/6 ISSUE #

Station: Holyrood	Unit #1	ALSTOM
Component Inspected: Casing ☐ Rotor ☐ HP ☐ IP ☐ LP1 ☐ LP2 ☐ LP3 ☐ Auxiliaries ☐ BFPT ☐ Stator ☒ Gen. Rotor ☐ Auxiliaries ☐ Exciter ☐ Valves ☐ MSR ☐ Controls ☐ Piping ☐ Component Serial Number:	Attachments; # PICTURES # RECORD SHEETS	Conformity: Yes ☐ No ☐ Design Response Required: Yes ☐ No ☐ Design Accepted: Yes ☐ No ☐
Contract # / Main Report #		CLIENT
Programme Reference:		Client Accepts Recommendation: Yes ☐ No ☐ Client Accepts 'As Found': Yes ☐ No ☐
Quality Plan Reference:		Signature: Date:

The front left foundation plate had 3 shims migrated, and approximately 50% of the thin vertical grout layer deteriorated.

Written By:	James George	Position: Technical Field Advisor	Date: 6/14/2012
Distribution For Action:	Client ☒	Engineering ☐	Project Manager ☐
Distribution For Information:	Client ☒	Engineering ☐	Project Manager ☐
CRN Reference no: (if applicable)			

POWER ALSTOM	STG INTERIM INSPECTION REPORT (IIR)	IIR # Gen006
Subject: Generator Foundation Plate shim migration		Sheet 3/6 ISSUE #

Station: Holyrood	Unit #1	ALSTOM Conformity: Yes ☐ No ☐ Design Response Required: Yes ☐ No ☐ Design Accepted: Yes ☐ No ☐
Component Inspected: Casing ☐ Rotor ☐ HP ☐ IP ☐ LP1 ☐ LP2 ☐ LP3 ☐ Auxiliaries ☐ BFPT ☐ Stator ☒ Gen. Rotor ☐ Auxiliaries ☐ Exciter ☐ Valves ☐ MSR ☐ Controls ☐ Piping ☐ Component Serial Number:	Attachments; # PICTURES # RECORD SHEETS	
Contract # / Main Report #		CLIENT Client Accepts Recommendation: Yes ☐ No ☐ Client Accepts 'As Found': Yes ☐ No ☐
Programme Reference:		
Quality Plan Reference:		Signature: Date:

The front right foundation plate had no shim migration, and approximately 25% of the thin vertical grout layer deteriorated.

Written By:	James George	Position: Technical Field Advisor	Date: 6/14/2012
Distribution For Action:	Client ☒	Engineering ☐	Project Manager ☐
Distribution For Information:	Client ☒	Engineering ☐	Project Manager ☐
CRN Reference no: (if applicable)			

POWER ALSTOM	STG INTERIM INSPECTION REPORT (IIR)		IIR # Gen006
Subject: Generator Foundation Plate shim migration			Sheet 4/6 ISSUE #
Station: Holyrood		Unit #1	ALSTOM Conformity: Yes ☐ No ☐ Design Response Required: Yes ☐ No ☐ Design Accepted: Yes ☐ No ☐
Component Inspected: Casing ☐ Rotor ☐ HP ☐ IP ☐ LP1 ☐ LP2 ☐ LP3 ☐ Auxiliaries ☐ BFPT ☐ Stator ☒ Gen. Rotor ☐ Auxiliaries ☐ Exciter ☐ Valves ☐ MSR ☐ Controls ☐ Piping ☐ Component Serial Number:		Attachments; # PICTURES # RECORD SHEETS	
Contract #	Main Report #		CLIENT Client Accepts Recommendation: Yes ☐ No ☐ Client Accepts 'As Found': Yes ☐ No ☐
Programme Reference:			
Quality Plan Reference:			Signature: Date:

The rear left foundation plate indicated that 1 shim has migrated. Approximately 50% of the thin vertical layer of grout has deteriorated.

Written By:	James George	Position: Technical Field Advisor	Date: 6/14/2012
Distribution For Action:	Client ☒	Engineering ☐	Project Manager ☐
Distribution For Information:	Client ☒	Engineering ☐	Project Manager ☐
CRN Reference no: (if applicable)			

POWER ALSTOM	STG INTERIM INSPECTION REPORT (IIR)	IIR # Gen006
Subject: Generator Foundation Plate shim migration		Sheet 5/6 ISSUE #

Station: Holyrood	Unit #1	ALSTOM
Component Inspected: Casing ☐ Rotor ☐ HP ☐ IP ☐ LP1 ☐ LP2 ☐ LP3 ☐ Auxiliaries ☐ BFPT ☐ Stator ☒ Gen. Rotor ☐ Auxiliaries ☐ Exciter ☐ Valves ☐ MSR ☐ Controls ☐ Piping ☐ Component Serial Number:	Attachments; # PICTURES # RECORD SHEETS	Conformity: Yes ☐ No ☐ Design Response Required: Yes ☐ No ☐ Design Accepted: Yes ☐ No ☐
Contract # / Main Report #		CLIENT Client Accepts Recommendation: Yes ☐ No ☐ Client Accepts 'As Found': Yes ☐ No ☐
Programme Reference:		
Quality Plan Reference:		Signature: Date:

The rear right foundation plate indicated that 3 shim have migrated. Approximately 60% of the thin vertical layer of grout has deteriorated.

Written By:	James George	Position: Technical Field Advisor	Date: 6/14/2012
Distribution For Action:	Client ☒	Engineering ☐	Project Manager ☐
Distribution For Information:	Client ☒	Engineering ☐	Project Manager ☐
CRN Reference no: (if applicable)			

POWER ALSTOM	STG INTERIM INSPECTION REPORT (IIR)	IIR # Gen006
Subject: Generator Foundation Plate shim migration		Sheet 6/6 ISSUE #

Station: Holyrood	Unit #1	ALSTOM Conformity: Yes ☐ No ☐ Design Response Required: Yes ☐ No ☐ Design Accepted: Yes ☐ No ☐
Component Inspected: Casing ☐ Rotor ☐ HP ☐ IP ☐ LP1 ☐ LP2 ☐ LP3 ☐ Auxiliaries ☐ BFPT ☐ Stator ☒ Gen. Rotor ☐ Auxiliaries ☐ Exciter ☐ Valves ☐ MSR ☐ Controls ☐ Piping ☐ Component Serial Number:	Attachments; # PICTURES # RECORD SHEETS	
Contract # / Main Report #		CLIENT Client Accepts Recommendation: Yes ☐ No ☐ Client Accepts 'As Found': Yes ☐ No ☐
Programme Reference:		
Quality Plan Reference:		Signature: Date:

Grout deterioration is common on older units. There was no evidence of freshly fallen grout after the January incident. The grout deterioration appears to be a pre-existing condition.

The generator stator does not seem to be experiencing vibrations during normal operation. Based on the electrical and bump tests performed on the stator, shim migration does not appear to be a condition expected in future operation.

Recommendations

- Cut front left shim which is making contact with the stator.

Schedule Impact Yes ☐ No ☒

Cost Impact Yes ☐ No ☒

Alstom's Engineering Department Recommendations

- Monitor shim migration in all areas of foundation plates during future operation.
- Monitor grout deterioration along foundation plates.

Customer's Response

Written By:	James George	Position: Technical Field Advisor	Date: 6/14/2012
Distribution For Action:	Client ☒	Engineering ☐	Project Manager ☐
Distribution For Information:	Client ☒	Engineering ☐	Project Manager ☐
CRN Reference no: (if applicable)			

ALSTOM POWER Thermal Services Rotating Plant	**INSPECTION REPORT**	**REPORT # TBC**
Subject: Rotor Visual Inspections		Sheet 1/1

Station: Holyrood Power Plant	Unit #: 1	ALSTOM Conformity: Yes ☒ No ☐ Design Response Required: Yes ☒ No ☐ Design Accepted: Yes ☐ No ☐
Component Inspected; Stator ☐ Rotor ☒ Exciter ☐ Auxiliaries ☐ Component Serial Number	Attachments; None	
Project #: 9PS01734 / Report # : TBC		CLIENT Client Accepts Recommendation: Yes ☐ No ☐ Client Accepts 'As Found': Yes ☐ No ☐
Programme Reference: N/A		
Quality Plan Reference:N/A		Signature: Date:

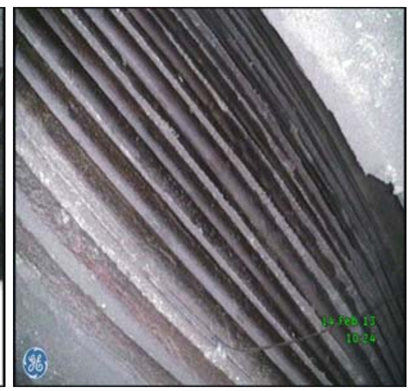
SITE INSPECTION

Report

Rotor Visual Inspections

Coil wedges in position, heavy black dust present.

Again heavy contamination.


Interturn insulation has seen high heat levels


Contamination @ base of stack of coil 1.


Brasied joints require cleaning

Blackened inter turn insulation

Written By:	David. Smith	Position: Generator Diagnostics Engineer		Date: 16/02/13
Distribution For Action:	Client ☐	Operations ☐	Engineering ☒	Project Manager ☒
Distribution For Information:	Client ☒	Operations ☒	Engineering ☒	Project Manager ☒
EWA Reference no: (if applicable)				

ALSTOM POWER Thermal Services Rotating Plant	INSPECTION REPORT	REPORT # TBC

Subject: Rotor Visual Inspections		Sheet 2/2
Station: Holyrood Power Plant	Unit #: 1	ALSTOM Conformity: Yes ☒ No ☐ Design Response Required: Yes ☒ No ☐ Design Accepted: Yes ☐ No ☐
Component Inspected; Stator ☐ Rotor ☒ Exciter ☐ Auxiliaries ☐ Component Serial Number	Attachments; None	
Project #: 9PS01734 / Report # : TBC		CLIENT Client Accepts Recommendation: Yes ☐ No ☐ Client Accepts 'As Found': Yes ☐ No ☐
Programme Reference: N/A		
Quality Plan Reference:N/A		Signature: Date:

Seems resin has run down the coils & been contaminated.Note debris at base of coils.

Slot exit insulation in position but contaminated throughtout.

Recommendations

The following is the opinion of the writer and may be subjected to correction, further comments and/or recommendations by the Engineering Department;
The visual inspections of the rotor windings show high levels of dust contamination. The Slip ring end of the rotor windings are more contaminated than the turbine end.
The interturn insulation seems to be in position, but in some areas has seen potentially high levels of heat. Cracking of insulation also blackening of insulation has been noted.
The dust contamination has spread to the slot exit insulation, again this insulation is in position.
The RSO tests have been performed & don't indicate any interturn shorts.
Insulation resistance tests have been performed giving a PI of greater than 3.

Written By:	David. Smith	Position: Generator Diagnostics Engineer		Date: 16/02/13
Distribution For Action:	Client ☐	Operations ☐	Engineering ☒	Project Manager ☒
Distribution For Information:	Client ☒	Operations ☒	Engineering ☒	Project Manager ☒
EWA Reference no: (if applicable)				

ALSTOM POWER Thermal Services Rotating Plant	INSPECTION REPORT	REPORT # TBC
Subject: Rotor Visual Inspections		Sheet 3/3
Station: Holyrood Power Plant	Unit #: 1	ALSTOM Conformity: Yes ☒ No ☐ Design Response Required: Yes ☒ No ☐ Design Accepted: Yes ☐ No ☐
Component Inspected; Stator ☐ Rotor ☒ Exciter ☐ Auxiliaries ☐ Component Serial Number	Attachments; None	
Project #: 9PS01734 / Report # : TBC		CLIENT Client Accepts Recommendation: Yes ☐ No ☐ Client Accepts 'As Found': Yes ☐ No ☐ Signature: Date:
Programme Reference: N/A		
Quality Plan Reference:N/A		

Due to the fact that this rotor has not had its retaining rings removed since approximately 1997. & the levels of contamination could pose a risk of an interturn short or a rotor earth fault occouring in the next 5 years. (the client wants the unit to run for approx. next 5 years).

It is therefore recommended that the retaining rings be removed & a full program of cleaning & testing be performed on this rotor replacing any liners / insulation as required.

A HV test should be performed after cleaning on all components including D leads radial stork insulation & winding insulation.

Mr. D Smith
Generator Diagnostics Engineer
Generator Operations
ALSTOM POWER THERMAL SERVICE UK

Written By:	David. Smith	Position: Generator Diagnostics Engineer		Date: 16/02/13
Distribution For Action:	Client ☐	Operations ☐	Engineering ☒	Project Manager ☒
Distribution For Information:	Client ☒	Operations ☒	Engineering ☒	Project Manager ☒
EWA Reference no: (if applicable)				

ALSTOM POWER Thermal Services Rotating Plant	**INSPECTION REPORT**		**REPORT # TBC**
Subject: Rotor Visual Inspections			**Sheet 4/4**
Station: Holyrood Power Plant		**Unit #: 1**	**ALSTOM** Conformity: Yes ☒ No ☐ Design Response Required: Yes ☒ No ☐ Design Accepted: Yes ☐ No ☐
Component Inspected; Stator ☐ Rotor ☒ Exciter ☐ Auxiliaries ☐ Component Serial Number		**Attachments;** None	
Project #: 9PS01734	Report # : TBC		CLIENT Client Accepts Recommendation: Yes ☐ No ☐ Client Accepts 'As Found': Yes ☐ No ☐
Programme Reference: N/A			
Quality Plan Reference:N/A			Signature: Date:

ENGINEERING DEPARTMENT RECOMMENDATIONS

There does not appear to be any evidence that the rotor endwindings have been adversely affected by the event which lead to the shutdown of the generator. The only issue found with the rotor windings is the contamination under the winding heads. It is not clear that this contamination is a recent development and not simply an accumulation of dirt and debris deposited over the previous 16 years (the previous inspection report from Spring 2012 also noted dirt in the rotor). The electrical tests performed all indicate that there are no problems currently with the winding. Given this information the winding is likely in the same condition as it was left after the Spring 2012 outage.

It should be understood that normal Alstom maintenance practice would call for removal of these retaining rings simply on the basis of the time since the previous rings-off inspection. However the inspection & testing results do not indicate any apparent fault with the rotor winding. If the customer were to decline to remove the retaining rings, the risk associated with running the generator for another 5 years would be small. This risk could be further mitigated by performing a 3 step elevated voltage test on the windings to provide further assurance that the winding is in satisfactory condition.

John Jensen
ALSTOM TSNAM
Richmond

Written By:	David. Smith	Position: Generator Diagnostics Engineer	Date: 16/02/13
Distribution For Action:	Client ☐	Operations ☐	Engineering ☒ Project Manager ☒
Distribution For Information:	Client ☒	Operations ☒	Engineering ☒ Project Manager ☒
EWA Reference no: (if applicable)			

ALSTOM POWER Thermal Services Rotating Plant	INSPECTION REPORT	REPORT # TBC
Subject: Rotor Visual Inspections		Sheet 5/5

Station: Holyrood Power Plant	Unit #: 1	ALSTOM Conformity: Yes ☒ No ☐ Design Response Required: Yes ☒ No ☐ Design Accepted: Yes ☐ No ☐
Component Inspected; Stator ☐ Rotor ☒ Exciter ☐ Auxiliaries ☐ Component Serial Number	Attachments; None	
Project #: 9PS01734 — Report # : TBC		CLIENT Client Accepts Recommendation: Yes ☐ No ☐ Client Accepts 'As Found': Yes ☐ No ☐
Programme Reference: N/A		
Quality Plan Reference:N/A		Signature: Date:

Customers Response

Written By:	David. Smith	Position: Generator Diagnostics Engineer		Date: 16/02/13
Distribution For Action:	Client ☐	Operations ☐	Engineering ☒	Project Manager ☒
Distribution For Information:	Client ☒	Operations ☒	Engineering ☒	Project Manager ☒
EWA Reference no: (if applicable)				

ALSTOM POWER Thermal Services Rotating Plant	INSPECTION REPORT	REPORT # TBC
Subject: Stator electrical tests		Sheet 1/1

Station: Holyrood Power Plant	Unit #: 1	ALSTOM Conformity: Yes ☒ No ☐ Design Response Required: Yes ☒ No ☐ Design Accepted: Yes ☐ No ☐
Component Inspected; Stator ☒ Rotor ☐ Exciter ☐ Auxiliaries ☐ Component Serial Number	Attachments; None	
Project #: 9PS01734 | Report # : TBC		CLIENT Client Accepts Recommendation: Yes ☐ No ☐ Client Accepts 'As Found': Yes ☐ No ☐
Programme Reference: N/A		
Quality Plan Reference:N/A		Signature: Date:

SITE INSPECTION

Report

Stator Tests

See El-cid results below:

Measurements Taken from NDE

Slot Number	Peak mA Level	Distance (M)	Slot Number	Peak mA Level	Distance (M)
1	36	2.65	**34**	35	2.86
2	39	2.81	**35**	31	0.52
3	32	3.1	**36**	36	2.4
4	32	2.41	**37**	36	1.98
5	34	2.29	**38**	35	1.34
6	35	2.38	**39**	36	2.7
7	37	1.21	**40**	40	0.31
8	31	0.35	**41**	40	0.28
9	38	0.64	**42**	40	3.55
10	33	2.7	**43**	39	3.48
11	32	0.71	**44**	38	1.92
12	38	3.61	**45**	40	1.31
13	36	3.71	**46**	40	2.96
14	35	3.56	**47**	40	2.63
15	42	2.83	**48**	39	2.56
16	36	2.53	**49**	40	3.48
17	39	2.8	**50**	38	3.501
18	37	1.84	**51**	41	3.59
19	37	1.49	**52**	34	2.58
20	32	1.57	**53**	35	2.01
21	38	1.16	**54**	37	0.87
22	37	0.98	**55**	34	0.35
23	34	2.84	**56**	33	3.58
24	40	2.08	**57**	32	3.41
25	32	0.62	**58**	35	1.76
26	34	3.13	**59**	31	0.133
27	33	2.81	**60**	31	0.08
28	34	2.9	**61**	32	0.26
29	31	2.9	**62**	28	1.46
30	35	2.74	**63**	29	0.99
31	36	2.3	**64**	27	2.84
32	41	0.62	**65**	30	1.41
33	37	0.48	**66**	29	1.09

Written By:	David. Smith	Position: Generator Diagnostics Engineer	Date: 12/02/13

Distribution For Action:	Client ☐	Operations ☐	Engineering ☐	Project Manager ☐
Distribution For Information:	Client ☒	Operations ☒	Engineering ☒	Project Manager ☒
EWA Reference no: (if applicable)				

ALSTOM POWER Thermal Services Rotating Plant	**INSPECTION REPORT**	**REPORT # TBC**
Subject: Stator electrical tests		**Sheet 2/2**

Station: Holyrood Power Plant	**Unit #: 1**	**ALSTOM** Conformity: Yes ☒ No ☐ Design Response Required: Yes ☒ No ☐ Design Accepted: Yes ☐ No ☐
Component Inspected; Stator ☒ Rotor ☐ Exciter ☐ Auxiliaries ☐ **Component Serial Number**	**Attachments;** None	
Project #: 9PS01734 — **Report # : TBC**		**CLIENT** Client Accepts Recommendation: Yes ☐ No ☐ Client Accepts 'As Found': Yes ☐ No ☐
Programme Reference: N/A		
Quality Plan Reference:N/A		**Signature:** **Date:**

Step packets were also measured. See results below:

NDE			NDE			DE			DE		
	Peak mA Level			Peak mA Level			Peak mA Level			Peak mA Level	
Slot Number	Step 1	Step 2	Slot Number	Step 1	Step 2	Slot Number	Step 1	Step 2	Slot Number	Step 1	Step 2
1	42	41	**34**	31	35	**1**	32	31	**34**	25	23
2	38	35	**35**	38	37	**2**	36	31	**35**	28	22
3	44	44	**36**	41	37	**3**	35	29	**36**	41	31
4	40	40	**37**	46	41	**4**	39	40	**37**	38	35
5	43	40	**38**	42	43	**5**	39	43	**38**	38	39
6	38	37	**39**	37	40	**6**	38	38	**39**	45	42
7	43	43	**40**	46	39	**7**	35	32	**40**	34	41
8	39	36	**41**	40	38	**8**	34	30	**41**	46	47
9	43	42	**42**	38	35	**9**	40	38	**42**	40	41
10	41	42	**43**	31	29	**10**	42	40	**43**	38	33
11	41	44	**44**	32	28	**11**	49	50	**44**	40	35
12	37	37	**45**	38	33	**12**	44	46	**45**	45	40
13	39	37	**46**	32	28	**13**	43	42	**46**	39	32
14	40	37	**47**	33	30	**14**	38	38	**47**	46	37
15	42	36	**48**	29	34	**15**	46	47	**48**	41	36
16	32	29	**49**	33	32	**16**	40	39	**49**	37	42
17	37	36	**50**	35	35	**17**	44	44	**50**	44	39
18	36	35	**51**	36	34	**18**	36	37	**51**	44	41
19	39	42	**52**	37	34	**19**	38	32	**52**	44	35
20	42	40	**53**	36	34	**20**	32	34	**53**	36	36
21	40	38	**54**	38	33	**21**	32	29	**54**	39	35
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23	32	43	**56**	35	35	**23**	40	42	**56**	42	42
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25	37	40	**58**	43	38	**25**	45	43	**58**	37	36
26	40	40	**59**	47	44	**26**	37	29	**59**	36	41
27	45	44	**60**	46	42	**27**	43	48	**60**	37	38
28	45	45	**61**	40	41	**28**	35	41	**61**	34	34
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30	42	43	**63**	42	42	**30**	44	45	**63**	29	29
31	46	46	**64**	42	39	**31**	37	35	**64**	20	25
32	41	39	**65**	41	39	**32**	41	32	**65**	27	29
33	44	40	**66**	38	44	**33**	47	39	**66**	32	33

Written By:	**David. Smith**	**Position: Generator Diagnostics Engineer**	**Date: 12/02/13**

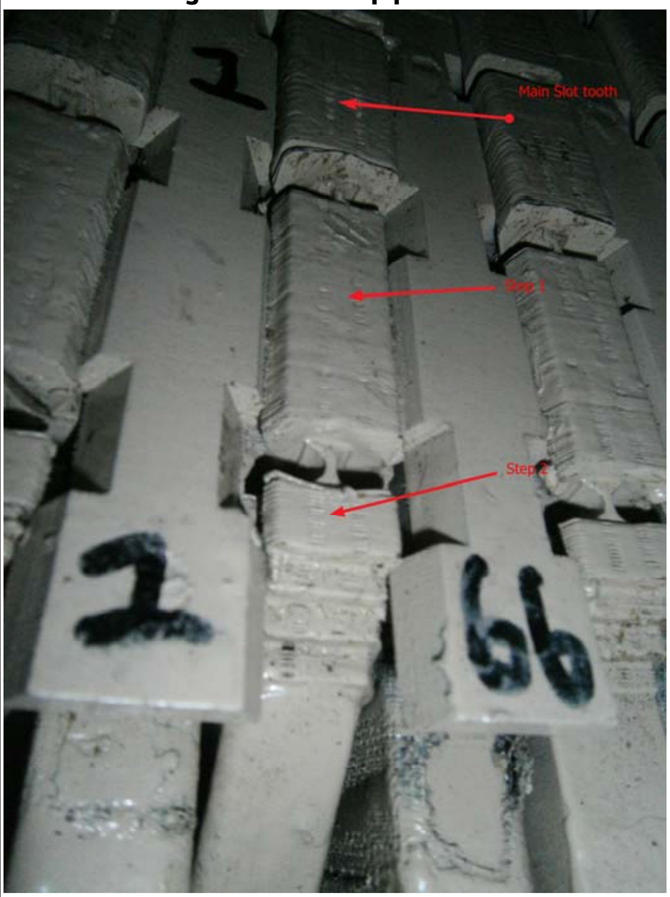
Distribution For Action: Client ☐ Operations ☐ Engineering ☐ Project Manager ☐

Distribution For Information: Client ☒ Operations ☒ Engineering ☒ Project Manager ☒

EWA Reference no: (if applicable)

ALSTOM POWER Thermal Services Rotating Plant	INSPECTION REPORT		REPORT # TBC
Subject: Stator electrical tests			Sheet 3/3
Station: Holyrood Power Plant		Unit #: 1	ALSTOM Conformity: Yes ☒ No ☐ Design Response Required: Yes ☒ No ☐ Design Accepted: Yes ☐ No ☐
Component Inspected; Stator ☒ Rotor ☐ Exciter ☐ Auxiliaries ☐ Component Serial Number		Attachments; None	
Project #: 9PS01734	Report # : TBC		CLIENT Client Accepts Recommendation: Yes ☐ No ☐ Client Accepts 'As Found': Yes ☐ No ☐
Programme Reference: N/A			
Quality Plan Reference:N/A			Signature: Date:

Picture showing accessible step packets:



Written By:	David. Smith	Position: Generator Diagnostics Engineer	Date: 12/02/13
Distribution For Action:	Client ☐	Operations ☐ Engineering ☐	Project Manager ☐
Distribution For Information:	Client ☒	Operations ☒ Engineering ☒	Project Manager ☒
EWA Reference no: (if applicable)			

ALSTOM POWER Thermal Services Rotating Plant	INSPECTION REPORT	REPORT # TBC
Subject: Stator electrical tests		Sheet 4/4
Station: Holyrood Power Plant	Unit #: 1	ALSTOM Conformity: Yes ☒ No ☐ Design Response Required: Yes ☒ No ☐ Design Accepted: Yes ☐ No ☐
Component Inspected; Stator ☒ Rotor ☐ Exciter ☐ Auxiliaries ☐ Component Serial Number	Attachments; None	
Project #: 9PS01734 — Report # : TBC		CLIENT Client Accepts Recommendation: Yes ☐ No ☐ Client Accepts 'As Found': Yes ☐ No ☐
Programme Reference: N/A		
Quality Plan Reference:N/A		Signature: Date:

Recommendations

The following is the opinion of the writer and may be subjected to correction, further comments and/or recommendations by the Engineering Department;

Due to a communications issue with the El-cid equipment, graphical data could not be obtained.
Results were manually taken & noted down.
The levels are typically around 35 – 40mA.
The maximum level before further investigations is 100mA.
All slots & slot steps measured are within the prescribed limit.
Visually no hotspots or damage was found in the stator bore or on the back of core during inspection.
Abrasion dust was spotted @ approx. 3 o'clock position from NDE. Boroscope inspection to try & find source of dust.

No further action required on El-cid tests.

Mr. D Smith
Generator Diagnostics Engineer
Generator Operations
ALSTOM POWER THERMAL SERVICE UK

Written By:	David. Smith	Position: Generator Diagnostics Engineer	Date: 12/02/13
Distribution For Action:	Client ☐	Operations ☐ Engineering ☐	Project Manager ☐
Distribution For Information:	Client ☒	Operations ☒ Engineering ☒	Project Manager ☒
EWA Reference no: (if applicable)			

ALSTOM POWER Thermal Services Rotating Plant	INSPECTION REPORT	REPORT # TBC
Subject: Stator electrical tests		Sheet 5/5

Station: Holyrood Power Plant	Unit #: 1	ALSTOM Conformity: Yes ☒ No ☐ Design Response Required: Yes ☒ No ☐ Design Accepted: Yes ☐ No ☐
Component Inspected; Stator ☒ Rotor ☐ Exciter ☐ Auxiliaries ☐ Component Serial Number	Attachments; None	
Project #: 9PS01734 Report # : TBC		CLIENT Client Accepts Recommendation: Yes ☐ No ☐ Client Accepts 'As Found': Yes ☐ No ☐
Programme Reference: N/A		
Quality Plan Reference:N/A		Signature: Date:

ENGINEERING DEPARTMENT RECOMMENDATIONS

The recommendations provided are confirmed. There are no additional Engineering recommendations.

John Jensen
ALSTOM TSNAM
Richmond

Written By:	David. Smith	Position: Generator Diagnostics Engineer		Date: 12/02/13
Distribution For Action:	Client ☐	Operations ☐	Engineering ☐	Project Manager ☐
Distribution For Information:	Client ☒	Operations ☒	Engineering ☒	Project Manager ☒
EWA Reference no: (if applicable)				

ALSTOM POWER Thermal Services Rotating Plant	INSPECTION REPORT	REPORT # TBC
Subject: Stator electrical tests		Sheet 6/6
Station: Holyrood Power Plant	Unit #: 1	ALSTOM Conformity: Yes ☒ No ☐ Design Response Required: Yes ☒ No ☐ Design Accepted: Yes ☐ No ☐
Component Inspected; Stator ☒ Rotor ☐ Exciter ☐ Auxiliaries ☐ Component Serial Number	Attachments; None	
Project #: 9PS01734 — Report # : TBC		CLIENT Client Accepts Recommendation: Yes ☐ No ☐ Client Accepts 'As Found': Yes ☐ No ☐
Programme Reference: N/A		
Quality Plan Reference:N/A		Signature: Date:

Customers Response

Written By:	David. Smith	Position: Generator Diagnostics Engineer	Date: 12/02/13
Distribution For Action:	Client ☐	Operations ☐	Engineering ☐ Project Manager ☐
Distribution For Information:	Client ☒	Operations ☒	Engineering ☒ Project Manager ☒
EWA Reference no: (if applicable)			

20 March 2013

Mr. Todd Collins, P. Eng.
Mechanical Design Engineer, Engineering Services
NALCOR Energy
Hydro Place, 500 Columbus Drive
PO Box 12400
St John's, NL, Canada
A1B 4K7

Dear Todd,

Holyrood Thermal Generating Station (Holyrood)
Unit 1 Steam Turbine Generator (STG) Assessment Support Report- Final

As per our Agreement, we have completed the summary report regarding our Holyrood Unit 1 STG Assessment Support involvement. I trust that the report satisfies your needs.

Thank you for the opportunity to work on this phase of this very interesting task.

Yours truly,

Blair Seckington

Blair Seckington
Director, Power Technology
Direct Tel.: 905-403-5004
Direct Fax: 905-829-1707
E-mail: blair.seckington@amec.com

BRS/brs

c: C. Woodall
c. G. Forbes
c: R.Merer

newfoundland labrador hydro
a nalcor energy company

Holyrood Thermal Generating Station

Unit 1 Steam Turbine Generator (STG) Assessment Support

March 20, 2013

Holyrood Thermal Generating Station

Unit 1 Steam Turbine Generator (STG) Assessment Support

171801-0000-280-RPT-0001r0

Rupert Merer ____________________ 20 Mar 2013
Prepared by: Date

Blair Seckington ____________________ 20 Mar 2013
Checked by: Date

Blair Seckington ____________________ 20 Mar 2013
Approved by: Date

Rev.	Description	Prepared By:	Checked:	Approved	Date
A	Draft Report	Rupert Merer	Blair Seckington		01 Mar 2013
0	Final Report	Rupert Merer	Blair Seckington	Blair Seckington	20 Mar 2013

IMPORTANT NOTICE

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HOLYROOD THERMAL GENERATING STATION
Unit 1 Steam Turbine Generator (STG) Assessment Support
EXECUTIVE SUMMARY

Holyrood Thermal Generating Station (Holyrood) Unit 1 experienced a significant event on Jan 11, 2013 that resulted in damage to the Unit 1 steam turbine and generator. NALCOR/Newfoundland and Labrador Hydro (Hydro) contracted with Alstom, their current steam turbine generator maintenance service provider, to undertake an initial inspection and test program. This was started January 21, 2013 and much of the initial inspection and testing has been completed at the time this report was initiated in mid-February.

Hydro also contacted AMEC Americas Limited (AMEC) around January 18, 2013 to request that AMEC provide specialist support in their evaluation of the impacts of the January 11, 2013 event on the condition of the Holyrood Unit 1 STG. AMEC had been involved in the Phase 1 Condition Assessment of the Holyrood units and were familiar with the design and condition of unit 1. AMEC staff provided support in the form of advice to Hydro staff and independent observation of Alstom's work. The AMEC work was extended to February 9, 2013 to include additional work as the unit was opened up for internal inspection, and to March 31, 2013 for the preparation of this informal report on the initial support work.

As a result of the assessment, AMEC makes the following conclusions and recommendations:

CONCLUSIONS

1. The Sequence of Events leading to the damage of Unit 1 STG was not fully understood, as of February 9, 2013 when AMEC's site work was finished.
2. Hydro's primary initial generator concerns about potential overstressing of the stator foundation, the rotor coupling or the stator support and damping system appear to have been eliminated.
3. There appears to be little visible generator damage evident beyond slight scoring of the journals and of the shaft around the hydrogen seals and oil seal rings, a small amount of greasing on the stator end windings and in the area of the belly bands, and some stains on the coil binding rings. No test results were available for review.
4. The schedule of generator tests and inspections (generator rotor out) agreed between Alstom and Hydro (identified in Section 6) appears reasonable.
5. The steam turbine damage observed is consistent with a rotor rundown without lubricating oil, although in places the damage is less than might be expected.
    a. No explanation is evident for the failure of the Unit 1 direct current (DC) lube oil pump.
6. Given the unit was not barred after the shutdown and probably suffered uneven cooling and hotspots caused by rubs, the rotor should be checked for straightness.
7. No steam turbine damage, resulting from the Jan 11, 2013 incident, has been identified apart from the visible damage to seals and turbine shrouding resulting from rubs.
    a. planned inspections should include measurement of the thickness of the shroud leading edge, as compared to design values. Particular attention should be paid to any notching on the shroud.
8. The turbine suffered seal rubs in diaphragm packings, oil deflector rings, blade tip and shaft labyrinth seals in all cylinders, and most of these seals will require replacement.

9. Alstom's proposal that those parts of the turbine which did not suffer any rub or other unusual stress do not require non-destructive evaluation (NDE) testing, is reasonable, given that the machine was thoroughly checked and inspected last year.

RECOMMENDATIONS

1. The Sequence of Events leading to the damage of Unit 1 STG should be documented.
2. Subject to Alstom/Hydro review and agreement, the schedule of generator tests and inspections (generator rotor out) agreed to between Alstom and Hydro (identified in Section 6) should be undertaken.
3. The root cause of the Unit 1 DC lube oil pump should be identified and mitigated.
4. All seals which suffered significant rubs should be replaced, including diaphragm packing seals, shaft labyrinth seals, blading tip seals and spill strips and blading axial seals.
5. Turbine inspection should include measurement of the thickness of the shroud leading edge, as compared to design values, with particular attention to any notching on the shroud.
6. Alstom's position that some parts of the steam turbine which did not suffer any rub or other unusual stress do not require NDE testing, should be acceptable.
7. The unit rotor should be checked for straightness.

TABLE OF CONTENTS

HOLYROOD THERMAL GENERATING STATION
Unit 1 Steam Turbine Generator (STG) Assessment Support

1 INTRODUCTION

Holyrood Thermal Generating Station (Holyrood) Unit 1 experienced a significant event on Jan 11, 2013 that resulted in damage to the Unit 1 steam turbine and generator. NALCOR/Newfoundland and Labrador Hydro (Hydro) contracted with Alstom, their current steam turbine generator maintenance service provider, to undertake an initial inspection and test program. Alstom started January 21, 2013 and as of February 9, 2013 had completed much of the initial inspection and testing.

Hydro also contacted AMEC Americas Limited (AMEC) around January 18, 2013 to request that AMEC provide specialist support in their evaluation of the impacts of the January 11, 2013 event on the condition of the Holyrood Unit 1 STG. AMEC had been involved in the Phase 1 Condition Assessment of the Holyrood units and were familiar with the design and condition of Unit 1. AMEC staff provided support in the form of advice to Hydro staff, and independent observation of Alstom's work. The AMEC work was extended to February 9, 2013 to include additional work as the units were opened up for internal inspection, and to March 31, 2013 for this informal report on the initial support work.

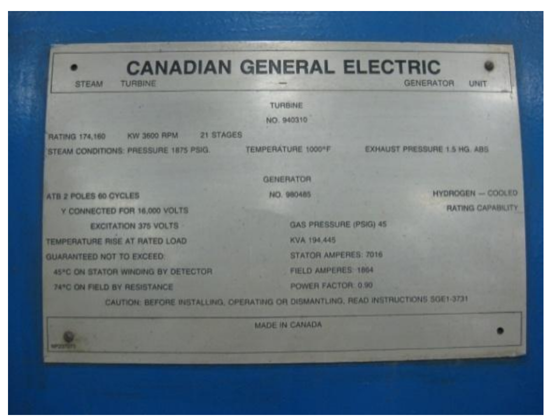
2 BACKGROUND

2.1 Holyrood Thermal Generating Station (Holyrood)

Holyrood is a three unit, nominally 500 megawatts (MW), heavy oil fired, steam cycle fossil generating station on the south shore of Conception Bay between the towns of Holyrood and Conception Bay South. Holyrood was constructed in two stages - Units 1 and 2 in the late 1960's and Unit 3 in 1977.

When all three units are in operation at full MCR (maximum continuous rating), Holyrood is capable of supplying approximately 33% of the Newfoundland and Labrador electricity demand. Typically, the units operate during the late fall to spring peak period and supply a minimum load of between 80 MW and 150 MW. The Unit 3 generator is also capable of synchronous condenser operation for grid voltage control.

2.2 Holyrood Unit 1 Steam Turbine Generator (STG)



UNIT 1 STEAM TURBINE GENERATOR

Unit #:	1
Asset Class #	BU 1296 - Assets Generations
SCI & System:	6691 #1 Turbine & Generator
Sub-Systems:	271309 #1 Steam turbine 6696 #1 Generator Assembly 6805 #1 Turbine Lubricating Oil 6807 #1Turbine Hydraulic Oil Systems

2.2.1 Holyrood Unit 1 Steam Turbine

The Unit 1 steam turbine went into service in 1970. It was originally a 150 MW turbine supplied by General Electrical (GE). The original turbine was a 1970 vintage Lynn D3 model. The turbine is rated to operate at a main steam inlet pressure of 13.0 megapascals gauge (MPag) (1890 pounds per square inch gauge (psig)) and steam temperature of 538 °C (1,000 °F). The reheat steam inlet temperature is 538 °C (1,000 °F). The turbine rotating speed is 3,600 revolutions per minute (RPM).

The unit consists of one combined high pressure (HP) and intermediate pressure (IP) turbine and one double flow low pressure (LP) turbine. The HP/IP and LP rotors are integral with the blade wheels. There is no centerline bore through the rotors. The turbine rotors are supported by three journal bearings. The trust bearing and the turning gear are located in the HP front standard.

The generator rotor is directly-coupled to the turbine. It is supported by two journal bearings located at the stator end-shields. In 1989, the unit was upgraded to produce 175 MW by replacing the HP/IP rotor and the HP/IP steam path components including the HP nozzle block. No changes were made to the LP turbine or the auxiliary equipment.

Unit 1 turbine has an upgraded Mark 5 Electro-Hydraulic Controlled (EHC) governor system with a partial arc steam admission system through 6 control valves. Unit 1 also has one main stop valve (MSV) with an internal pilot valve to control the run up of the turbine to full speed. There are two combined casing reheat stop and intercept valves.

The steam seal regulator (SSR) controls the flow of steam to and from all of the turbine shaft seals. The seals minimize the leakage of steam from the turbine casings. There SSR must be able to respond differently at low and high loads.

2.2.2 Holyrood Unit 1 Generator

The Unit 1 generator, supplied by Canadian General Electric, Peterborough, is hydrogen-cooled and rated at 194,445 KVA (kilovolt-amperes). The stator core and windings are flexibly-mounted in the stator frame, which contains four vertical hydrogen coolers. The stator windings operate at 16.0 KV (kilovolts) and are indirectly cooled by hydrogen. The hydrogen is circulated throughout the generator in a closed system, at a pressure of 310 kPag (45 psig) by an axial fan mounted on each end of the rotor. An isolated phase bus delivers the power from the generator to the unit transformer.

The generator rotor is directly-coupled to the turbine, and is supported on bearings located in the end-shields of the stator frame. Hydrogen seals prevent hydrogen from escaping from the generator. The seals are pressurised by oil and are located inboard of the bearings. The field windings are directly-cooled by hydrogen, fed via axial sub-slots and radial gas passages in the copper winding. The field windings are supported by retaining rings shrunk onto the ends of the rotor body. The field current is supplied to the field windings via collector rings and brush gear, outboard of the main bearing – there is no steady bearing. There is an unused thrust bearing collar at the turbine end of the generator shaft, for future synchronous condenser use.

The excitation to the field is now supplied by an ABB Unitrol static thyristor excitation system, with a fast response automatic voltage regulator to control the field current and MVAR (megavolt-ampere reactive) output from the generator. The excitation has a high ceiling voltage capability to enable the generator to help the power system recover from faults and disturbances.

Other generator auxiliary systems include:

- A seal oil system, with a differential pressure controller to keep the hydrogen contained within the generator;
- A closed-loop distilled water hydrogen cooling system and temperature controller to remove the heat from the generator;
- A hydrogen pressure control valve to provide automatic make-up from the bulk hydrogen supply, (at increased hydrogen pressure if overload is required);
- A scavenging system to remove the hydrogen that becomes entrained in the bearing oil and the seal oil;
- Potential transformers (PT's), located below the isolated phase bus, to measure the generator voltage; current transformers (CT's) mounted over the generator lead bushings to measure the generator current. These devices provide signals to measure the generator output, and for the electro-mechanical protection relays;
- A vibration monitoring system which continuously monitors the vibration amplitudes at each turbine generator bearing in the control room, and alerts the operator to increasing vibration, especially during run-up, load changes and shut-down. It uses two proximity probes at 45° to the vertical to measure the shaft vibration level; and
- A digital multi-functional generator protection relay has been added, but at present it is primarily used for extra ground fault protection of the stator windings (which are in poor condition). It also provides supplementary alarms and sequence-of-events monitoring.

2.2.3 Lube Oil System

The lube oil system is integrated into a system for both the steam turbine and the generator. It consists of a storage system, AC (alternating current) and DC pumping systems, filtration, and heat exchangers. The lube oil tank holds approximately 98400 litres (L) (2600 US gallons) of Turboflo R&O 32 lubricating oil. Within the lube oil tank, there are three pumping units (two 100% AC motor driven and one 100% DC motor driven) and three 100% duty lube oil heat exchangers. The system supplies 35-45 °C oil to the turbine/generator lubrication and hydrogen seal oil systems. Pump discharge pressures at 275 – 300 kilopascals (kPa) would be normal.

Lubricating oil heat exchanger cooling water heads can be isolated and removed for easy cleaning. An oil purifier is connected to the oil tank through a separate piping arrangement and is used primarily to remove water from the oil which accumulates because of the condensation throughout the process. The system is fitted with two 100% duty oil filters insuring heavy particles in the oil are removed and do not reach the bearings during lubrication.

Two 100% positive displacement hydraulic oil pumps are used to operate the emergency stop valve, the combined intercept reheat stop valves, the control valves and other miscellaneous valves on the steam turbine. The pumps operate at a pressure of 15.5 MPa to counteract the large springs which normally hold the valves closed. The hydraulic oil system has its own network of high pressure piping external to the lubricating oil system which makes it somewhat easier to maintain if problems occur.

2.3 Recent Overhauls

The Holyrood Unit 1 steam turbine generator had major overhauls in 2003 and 2012 and a valve overhaul in 2009. At the beginning of 2013 it had only operated for 3 months (about 1500 operating hours) since the end of the 2012 overhaul

In the 2003 major overhaul General Electric (GE) found that the moving blades and diaphragms were generally in good condition. One brazing repair was required on stage 4 Low Pressure (LP) lacing wire and diaphragm packings had rubbed on two stages on the Intermediate Pressure (IP) and 2 stages of the LP rear (collector end). In addition the spill strips had rubbed on four stages of High Pressure (HP) blading. In each case GE sharpened the packing or spill strip. Some diaphragms required minor repairs including HP stage 2 upper and lower, stage 3 lower and stage 6 upper. In each case grinding or weld repairs were performed. In the LP two diaphragms (out of 20 upper and lower diaphragms in the machine) required minor repairs and grinding of indications. In 2003 a number of crack indications in the HP, IP and LP inner and outer casings were ground out and a weld repair was made adjacent to a strut in the LP outer casing.

The most significant damage found in 2003 was to the HP nozzle plates, with resulting localized distortion of the HP inner cylinder and this necessitated the removal of the HP lower inner casing and shipping the upper and lower casings and the nozzle plates to a GE shop in Buffalo . GE then recommended that Hydro hold spare upper and lower nozzle plates. GE did not expect that the distortion of the HP inner casing around the nozzle plates would reoccur soon.

In 2009 a valve overhaul was performed on the machine, and because the HP nozzle plates had failed on Unit 2 in 2007 and had been found damaged on Unit 1 in 2003, they were examining by borescope. It was found that some of the partition plates had moved, so the HP-IP cylinder was opened and the nozzle plates replaced. At this time HP stages 1 to 3 were found to have extensive Foreign Object Damage (FOD) resulting from boiler tube repairs and the blades were dressed.

In 2012 no crack indications were found on the inner and outer casing, diaphragms or blades, in contrast to the 2003 overhaul. After nine years of operation, there seemed to be no visible damage to the entire running line. Even though the HP-IP cylinder had been opened in 2009 for the replacement of the nozzle partition plates, no work was done in 2009 on the casings, diaphragms, rotors of blades (apart from dressing HP 1-3 which had suffered FOD). The HP nozzle plates also looked satisfactory.

3 SEQUENCE OF EVENTS - JAN 11, 2013 UNIT 1 STG INCIDENT

Just over 3 months after the Unit 1 steam turbine generator was started following its 2012 major overhaul, it appears to have been damaged by a loss of power event which resulted in the STG running down without lube oil.

During site visits from Jan 20 to Feb 9, 2013, AMEC was not able to determine with certainty the sequence of events from Jan 11, 2013 which affected the Unit 1 STG. No written reports on the Jan 11th 2013 incident were available or provided. Early verbal reports suggested that the generator had tripped, and that while running down it had been re-energized from the switchyard while still rotating at 3000 RPM. It was indicated in verbal reports by station personnel and control room staff that this had caused severe generator vibration and subsequently a hydrogen fire at the turbine end of the generator. The verbal reports indicated that the generator had moved on its foundation, that there had been several bearing oil fires, and that the unit took a total of 7 minutes to come to rest, accompanied by a high level of noise ("like a helicopter") and vibration.

Initially most of Hydro's concern related to the generator. When the Foxboro speed data became available, it appeared that the unit did not in fact attempt to re-synchronize. This eliminated the main generator concerns about potential overstressing of the rotor coupling or the stator support and damping system.

The Foxboro distributed control system (DCS) indicated that Unit 1 was operating at 110 MW when the plant was disconnected from the grid and that it also lost all auxiliary power. Unit 2 was also operating on load, but Unit 3 was shut down. The Unit 1 turbine speed rose momentarily to about 3900 RPM before dropping to 2800 RPM in just over 2 minutes. At that point the Foxboro DCS data suggests that the unit stopped almost instantaneously, but this was probably the result of the failure of all of the speed sensors due to high vibration.

The exact sequence of events is important because it should provide some indication of which parts of the STG machine may have been highly stressed during the incident. For example, if the generator tried to resynchronize, it would have put a high stress on the coupling and possibly on the stator support system.

The Unit 1 DC oil pump failed to start. As a result, the unit ran without oil for about 3 minutes. The unit data shows oil pressure falling 13 seconds after the failure and being restored 3 minutes and 6 seconds later, when the emergency diesel generators had been started and power restored to the AC oil pumps. It is not known how long it took the turbine to come to rest or if the vacuum was broken. In contrast, the DC oil pump on Unit 2 apparently operated correctly and brought that unit to a successful shutdown. As of February 9, 2013 when this report was initiated, there was no explanation for the failure of the Unit 1 DC pump. It had apparently been checked the previous day. Also both the pump and motor operated correctly when they were checked after the incident.

AMEC has not been provided with a log of bearing vibrations. AMEC briefly saw a printout from the DCS, but the printout did not have a scale, consequently the magnitude of the vibrations is not known. Bearing vibration is not normally a major excitation source of blade vibration damage, and the high bearing vibrations only occurred for a relatively short time (station management advise that the unit took 7 minutes to stop, but this is longer than would have been expected.) As the unit was running down the vibrations would have varied from 60 Hz to 0 and the unit would not have spent any time running at a particular critical speed or at a key blade vibration frequency. Despite this, it would be useful to understand the stress that the machine suffered. It is likely that the vibrations loosened some fixtures and instrumentation attached to the machine.

4 ASSESSMENT SCOPE/PARAMETERS OF STUDY

Hydro contacted AMEC around January 18, 2013 to request that AMEC provide specialist support in their evaluation of the impacts of the January 11, 2013 event on the condition of the Holyrood Unit 1 STG.

Initially the work involved the provision of specialist support to Hydro during the initial Phase 1 Unit 1 steam turbine generator damage inspection. The inspection was performed by the current STG service provider, Alstom in period Jan 21 to 28, 2013. AMEC staff provided support in the form of advice to Hydro staff and observation of Alstom's work. The work was further extended to February 9, 2013 to include additional work when the units were opened up and to March 31, 2013 for this informal report on the initial support work.

During this period, AMEC personnel were acting under Hydro's direction and control for this work. The scope consisted of:

- Participation in site safety training
- Review of existing information on unit, unit overhaul, incident reports as background
- Review of client and vendor (Alstom) inspection plans and findings
- Participation in equipment inspections and consultations as required to develop third party positions
- Provision of comments to client on Alstom proposed testing, potential issues, and other concerns
- Meetings with client and Alstom on findings and progress

AMEC's responsibilities did not include the provision of direction or supervision of client or vendor (Alstom) work or staff. Neither did AMEC assume any liability for damages or consequential damages as a result of work actually performed or not.

4.1 Site Visits

Rupert Merer of AMEC was on site for most days during the period January 21, 2013 to February 9, 2013. He undertook numerous meetings with Hydro and Alstom staff during that period, including interviews with station management and operations staff. He also reviewed information and pictures from the incident and participated in visual inspections of the units where practical.

5 DISASSEMBLY OF TURBINE-GENERATOR

Hydro utilized Alstom, their STG service provider, to disassemble and inspect/test the steam turbine generator. Many members of the Alstom team had worked on the 2012 major overhaul a few months earlier and were familiar with the equipment. This included the Alstom Manager and Technical Field Advisor (TFA).

The work proceeded below budget and ahead of schedule, and with few disruptions. It was well managed, and the site was kept tidy and safe. There were a few relatively minor issues identified below, but overall the work was of high quality.

- Major lifting was managed well and will due care although Alstom did not always plan laydown area adequately. For example, when the HP-IP outer top half casing was lowered to the basement, that there wasn't sufficient space without moving other items. The rearrangement did not take long, but some time was wasted in moving items a second or third time.
- The workforce was generally efficient, although the work lost momentum when the phase one work was complete and Alstom were awaiting confirmation of the second phase.
- Parts were sometimes not marked after removal which led to confusion - for example oil deflector rings. Some other components had too many conflicting markings- some of which were out of date.
- The work was delayed slightly by Hydro's crane problems.

One issue considered significant for future work related to the generator:

- The generator rotor was stored in an unheated tent which should have been provided with some background heat.
- The generator stator was not kept heated or kept dry with dehumidified air.

5.1 Inspection Results

Bearings: When the STG unit was initially dismantled, it was found that bearing damage at the generator end was far less severe than at the turbine end. The generator Collector End (CE) bearing was damaged, but had its white metal intact, while the turbine bearings had lost all of their white metal. It is assumed that the generator bearings received some lubrication from the seal oil system, but this is unproven. Two of the turbine bearings (No 1 and No 2) had suffered oil fires.

Generator Hydrogen Seals: The generator hydrogen seals were not badly damaged and it appeared unlikely that they would have allowed enough hydrogen to leak to cause the reported hydrogen fire. Alstom staff stated that they do not believe that there was a hydrogen fire. AMEC considered their input and find their conclusion to be reasonable.

Generator Oil Deflectors: The generator outboard oil deflectors are badly damaged- almost flattened in places, while the inboard deflectors appear to be almost undamaged.

ST Rotors: When the steam turbine rotors were removed, it was observed that no turbine wheel or blade and no diaphragm blade or body had rubbed during the unit rundown. However all oil deflectors, which had been set with a clearance of about 5 mils, had rubbed, most of them severely. Also, most blade tip spill strips had rubbed on the blade shrouding and were damaged or destroyed.

Labyrinth Seals The inlet labyrinth seals on the HP are surprisingly undamaged, although there is some discolouration which indicates heating. The IP exhaust steam seals, at the LP turbine end, are damaged, as are all LP steam seals.

Diaphragms: Diaphragm packings are largely undamaged in the HP, and only moderately damaged in the IP and LP. In all cases there are rub marks on the rotor. In some cases adjacent diaphragm packings have completely different amounts of wear, which suggests that one of the spring backings jammed, although is it possible that one diaphragm clearance wasn't set properly in the 2012 overhaul.

5.2 Analysis

The complete loss of white metal on the thrust bearing and all of the turbine journal bearings should have resulted in the rotor moving forward about 0.375 inches and down by a similar amount, and more severe rub damage throughout the machine might have been expected. This leads to the preliminary suspicion that the complete loss of white metal occurred when the unit had almost stopped, or that some white metal melting may have continued after the unit had stopped.

As noted there are no rubs on the steam turbine blades themselves, but many stages of HP and IP shrouding show signs of rubbing on the leading edge from tip seals. HP stage 2 has lost the shroud leading edge from about 7 packets of blading, with 5 blades per packet. While most HP stages have rubbed at the radial spill strips, which are supported by the diaphragm outer ring, but there is no sign of rubbing from diaphragm axial seals, which are supported below the diaphragm nozzle.

There are several anomalies in the amount of wear suffered. As noted, the generator outboard oil deflectors are badly damaged, while the inboard deflectors appear to be almost undamaged. This indicates that the rotor movement outboard of bearing # 4 was far greater than it was inboard of the bearing. At present, no plausible explanation for this has been identified. In another case of uneven wear, the spill strips on the LP rear blading are all broken, but those on the LP front blading are largely undamaged.

Generator: Initially most of Hydro's concern related to the generator, as witnesses' verbal reports indicated that it had moved on its foundation, suffered a hydrogen fire, and vibrated very heavily. When the Foxboro DCS speed data became available, it appeared that the unit did not attempt to re-synchronize. This eliminated the main generator concerns about potential overstressing of the rotor coupling or the stator support and damping system.

With the generator rotor removed, there was little additional damage evident. There was slight scoring of the journals and around the hydrogen seal journal and oil seal rings, minor greasing of the end windings and around the belly bands, and some stains on the coil binding rings, but nothing else visible.

Given the relatively small amount of damage suffered by the generator bearings and the condition of the hydrogen seals, it is not clear why verbal reports by witnesses singled out the generator vibration on run down rather than turbine vibration. It may be because the generator is closer to the observers in the control room. The principal driver of generator damage appears to be the high vibrations experienced during rundown. As the generator bearings show much less damage and signs of overheating than those of the turbine, the reported high generator vibration isn't yet explained. It should be noted that the shims under the generator at the turbine end were loose, but it is not known for certain if the unit moved vertically or not.

Steam turbine: The steam turbine damage observed is consistent with a rotor rundown without lubricating oil, although in places the damage is less than might be expected. There was clearly some serious rubbing in some parts of the rotor, but the fact that it occurred over such a short period of time may explain why the effect is fairly limited. It should be noted that the unit was not barred after the shutdown so it probably also subsequently suffered uneven cooling. The rotor will be checked in a lathe for straightness.

The turbine suffered seal rubs in diaphragm packings and labyrinth seals in all cylinders, and most of these seals will require replacement. Several stages of HP shrouding suffered quite serious rubbing on the leading edge, while IP shroud rubs can also be seen on several stages.

Given the limited knowledge of the incident, the major forces acting on the turbine generator appear to have been;

- High vibration for up to 7 minutes
- Rotor journal heating
- Bearing damage
- Rubs with heat generation on turbine shrouding and under diaphragm packings

The impacts of these factors on the turbine are expected to be:

1. The localized heating of the HP-IP rotor may have given it a bow. This will be checked shortly.
2. HP-IP rotor integrity. This rotor was installed in 1989 and has only about 120,000 hours of operation. It has not been subjected to frequent cold or hot starts. No information was provided/available on the rotor forging or any testing which may have been done on it in the past, but its service duty to date is well within the capability of a normal chromium/molybdenum/vanadium (Cr/Mo/V) rotor of this size. The localized heating experienced during this incident would not be expected to materially affect its life. On a rotor of this type measurement of hardness can be used as a proxy for creep, but we do not know if such testing has been done.
3. HP stage 1 shrouding. The leading edge of this shroud has suffered a fairly firm rub. The blades have integral shrouding with a cover band and a single tenon per blade. The rubbing has occurred on the leading edge of the integral shroud but the band and tenon are not affected. Any failure would therefore involve the shroud leading edge of a single blade and not a packet. The leading edge of this shroud should be inspected carefully as discussed below.
4. HP stage 2 shrouding- the leading edge has broken away on about 7 packets of 5 blades per packet. This blading will require replacement.
5. Other HP and IP stages have suffered rubs and should be inspected for shroud thinning and notching.
6. LP rotor. This is a standard GE rotor which has operated for over 180,000 hours, and an average of fewer than 15 starts per year. We have no data on any metallurgical or other life assessment testing which might have been done on it. Some Alstom personnel suggested a boresonic examination of this rotor but it doesn't have a bore. The qualities required for an LP rotor are tensile strength and ductility, high cycle fatigue strength and torsional strength. Based on our knowledge of the Jan 11 incident it doesn't seem likely that the LP rotor was overloaded in any of

these areas- it may have experienced a high vibration excitation force, but only for a short time. During the rundown the rotor would not have spent any time at a shaft or blading critical speed.

7. The LP lacing wire required repair in the 2003 overhaul although it was in good condition in 2012. This feature is a weakness in many turbine types and should be inspected.

6 NON-DESTRUCTIVE EVALUATION (NDE) AND TESTING SCOPE

As of February 9, 2013, AMEC has not seen Alstom's proposed NDE plan for either the steam turbine or generator.

6.1 Steam Turbine

When the machine was opened for the 2012 major overhaul the turbine steam path had almost no damage and only a few minor rubs. It would be expected that the turbine was in good condition before the Jan 11, 2013 incident. To February 9, 2013, no elements of the Jan 11, 2013 incident have been identified that would have severely damaged the steam turbine, apart from the extensive rubs.

It is recommended that the planned inspection should include measurement of the thickness of the shroud leading edge, as compared to design values. Particular attention should be paid to any notching on the shroud.

On the basis of information available, we would agree with Alstom that some parts of the turbine which did not suffer any rub or other unusual stress do not require NDE testing, given that the machine was thoroughly checked and inspected last year.

6.2 Generator

A schedule of generator tests and inspections (generator rotor out) was agreed by Alstom and Hydro. AMEC concurs on the reasonableness of the proposed scope of tests. The proposed tests are listed below. As of February 9, 2013, no test results were available or analysis completed.

6.2.1 Inspection and Testing of Generator Stator

- Visual inspection of stator windings and phase rings for loose blocks or ties, dusting, greasing, corona, etc.
- Full stator frame inspection with particular attention behind the core looking for cracks and signs of distress
- Visual inspection of support system for broken or loose components, dusting, greasing, etc.
- Visual inspection of stator core for hot spots, surface damage, wedge condition, etc.
- El-CID test on stator core
- Tightness check on stator slot wedging
- Insulation resistance test with polarization index (5 kV DC for 10 minute) on stator winding and bushings
- DC leakage test (from 5 kV DC to 32 kV DC) on each phase of the stator winding and bushings (requires removal of stator bar to enable testing between phases)
- Existing equipment (i.e. thermocouples (TC's) in core, winding resistance temperature detectors (RTD's), etc.) inspection and testing
- Stator Digital Resistance Ohmmeter (DLRO) Test

6.2.2 Inspection and Testing of Generator Stator

- Visual inspection of rotor (couplings, journals, seal areas, retaining rings, body and wedges, etc.)
- Insulation resistance test (500 volts DC for 1 minute) on rotor winding
- Pole balance test (100 volts AC/10 amps) on rotor winding
- Winding resistance measurement
- Recurrent Surge Oscillograph (RSO) test to inspect for shorted turns

6.2.3 Generator Support

- Full inspection of generator foot, grout, shims, and foundation looking for cracks and signs of distress

6.2.4 Notes and Clarifications

- All electrical testing will be subject to acceptable visual inspection
- All tests have to be executed after review and signed off Alstom written procedure and confirming electrical parameters

7 CONCLUSIONS

1. The Sequence of Events leading to the damage of Unit 1 STG was not fully understood, as of February 9, 2013 when AMEC's site work was finished.
2. Hydro's primary initial generator concerns about potential overstressing of the stator foundation, the rotor coupling or the stator support and damping system appear to have been eliminated.
3. There appears to be little visible generator damage evident beyond slight scoring of the journals and of the shaft around the hydrogen seals and oil seal rings, a small amount of greasing on the stator end windings and in the area of the belly bands, and some stains on the coil binding rings. No test results were available for review.
4. The schedule of generator tests and inspections (generator rotor out) agreed between Alstom and Hydro (identified in Section 6) appears reasonable.
5. The steam turbine damage observed is consistent with a rotor rundown without lubricating oil, although in places the damage is less than might be expected.
    a. No explanation is evident for the failure of the Unit 1 direct current (DC) lube oil pump.
6. Given the unit was not barred after the shutdown and probably suffered uneven cooling and hotspots caused by rubs, the rotor should be checked for straightness.
7. No steam turbine damage, resulting from the Jan 11, 2013 incident, has been identified apart from the visible damage to seals and turbine shrouding resulting from rubs.
    a. planned inspections should include measurement of the thickness of the shroud leading edge, as compared to design values. Particular attention should be paid to any notching on the shroud.
8. The turbine suffered seal rubs in diaphragm packings, oil deflector rings, blade tip and shaft labyrinth seals in all cylinders, and most of these seals will require replacement.
9. Alstom's proposal that those parts of the turbine which did not suffer any rub or other unusual stress do not require non-destructive evaluation (NDE) testing, is reasonable, given that the machine was thoroughly checked and inspected last year.

8 RECOMMENDATIONS

1. The Sequence of Events leading to the damage of Unit 1 STG should be documented.
2. Subject to Alstom/Hydro review and agreement, the schedule of generator tests and inspections (generator rotor out) agreed to between Alstom and Hydro (identified in Section 6) should be undertaken.
3. The root cause of the Unit 1 DC lube oil pump should be identified and mitigated.
4. All seals which suffered significant rubs should be replaced, including diaphragm packing seals, shaft labyrinth seals, blading tip seals and spill strips and blading axial seals.
5. Turbine inspection should include measurement of the thickness of the shroud leading edge, as compared to design values, with particular attention to any notching on the shroud.
6. Alstom's position that some parts of the steam turbine which did not suffer any rub or other unusual stress do not require NDE testing, should be acceptable.
7. The unit rotor should be checked for straightness.