newfoundland labrador
hydro
a nalcor energy company

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March 29, 2015

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 the approval of the Replacement of the lower reheater boiler tubes on Units 1 and 2, and additional reliability improvements at the Holyrood Thermal Generating Station

Please find enclosed the original and 12 copies of the above-noted Application, plus supporting affidavit, project proposal, and draft order.

The proposed project involves the Replacement of the lower reheater boiler tubes on Units 1 and 2, and additional reliability improvements at the Holyrood Thermal Generating Station.

Should you have any questions, please contact the undersigned.

Yours truly,

NEWFOUNDLAND AND LABRADOR HYDRO

Tracey Pennell

Tracey L. Pennell
Legal Counsel

TLP/bs

cc: Gerard Hayes – Newfoundland Power
Paul Coxworthy – Stewart McKelvey Stirling Scales
Sheryl Nisenbaum – Praxair Canada Inc.
Thomas Johnson – Consumer Advocate
Thomas J. O'Reilly, Q.C. – Cox & Palmer

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 (Hydro) pursuant to Subsection 41(3) of the *Act*, for approval to replace the lower reheater boiler tubes on Units 1 and 2, and additional reliability improvements 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. Hydro is the primary generator of electricity in Newfoundland and Labrador. As part of its generating assets, Hydro owns and operates the Holyrood Thermal Generating Station (Holyrood TGS), which has three generating units with a combined generating capacity of 490 MW. Holyrood is an essential part of the Island Interconnected System and produces up to 40 percent of the Island's annual energy requirements.

3. In January and February 2016, the boiler lower reheater tubes on Units 1 and 2 experienced failures. Thirty reheater tubes (twenty-seven lower tubes) were replaced on Unit 2 from January to February 2016 and sixteen reheater tubes were replaced on Unit 1 in February 2016. While both units are now in service, in order to preserve the integrity of the remaining reheat tubes prior to replacement, the units have been

derated to 120 MW and will not exceed that maximum load until additional replacement of tubes in the lower reheater section is complete.

4. Hydro is proposing to replace the remaining tubing in the lower sections of the boiler reheaters in Units 1 and 2. Secondary to the tube replacements, Hydro is proposing additional reliability improvements for the Holyrood TGS. This includes replacing end of life equipment, including valve and piping replacements, No. 2 air compressor replacement, pump motor starter replacements, and heat exchanger replacements, as well as condition assessments of boiler and feedwater equipment.

5. This project is required to ensure Hydro is able to provide safe and reliable service to customers. The reheater section of the boiler must be functional to sustain operation and output of the generating unit. Based on the reheater tube failures that occurred on Units 1 and 2 in January and February 2016, replacement of the boiler lower reheater tubes must be completed to ensure reliable operation. In light of the recent age related tube failures, Hydro has, in the last two months, re-evaluated a number of aspects of systems to identify equipment that is at risk of failure. The secondary aspect of this project, which is to complete additional reliability improvements to replace critical equipment and conduct level 2 condition assessments, are required due to age, and condition assessment that indicates the various components could be at risk of failure.

6. The availability and reliability of Holyrood is critical to ensuring that adequate generating capability is maintained on the Island Interconnected System.

7. Hydro is recommending that the lower reheater tubes that service Units 1 and 2 boilers at the Holyrood TGS be replaced and that additional reliability improvements to replace critical equipment and conduct level 2 condition assessments be completed. Details regarding Hydro's proposal are contained in the attached project proposal document.

8. The estimated cost of this project is $11,800,000.

9. Hydro submits that the replacement of the lower reheater tubes that service Units 1 and 2 boilers at the Holyrood TGS and additional reliability improvements to replace critical equipment and conduct level 2 condition assessments at the Holyrood TGS are necessary to ensure that Hydro can continue to provide service which is safe and adequate and just and reasonable as required by Section 37 of the Act. An Engineering Report supporting this supplemental capital application is attached.

10. Hydro therefore makes Application for an Order pursuant to section 41(3) of the Act approving the replacement of the lower reheater tubes that service Unit 1 and 2 boilers at the Holyrood TGS and additional reliability improvements to replace critical equipment and conduct level 2 condition assessments at the Holyrood TGS at an estimated capital cost of $11,800,000, 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 29th day of March, 2016.

Tracey Pennell

Tracey L. Pennell
Counsel for the Applicant
Newfoundland and Labrador Hydro
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St. John's,
Newfoundland and Labrador
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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 (Hydro) pursuant to Subsection 41(3) of the *Act*, for approval to replace the lower reheater boiler tubes on Units 1 and 2, and additional reliability improvements at the Holyrood Thermal Generating Station.

AFFIDAVIT

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

1. I am the General Manager, Hydro Production of Newfoundland and Labrador Hydro, the Applicant named in the attached Application.

2. I have read and understand the foregoing Application.

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

SWORN at St. John's in the)
Province of Newfoundland and)
Labrador,)
this 29th day of March 2016,)
before me:)

Tracey Pennell

Barrister – Newfoundland and Labrador

Jennifer Williams

Jennifer Williams

A REPORT TO
THE BOARD OF COMMISSIONERS OF PUBLIC UTILITIES

REGISTERED PROFESSIONAL ENGINEER PEG Newfoundland and Labrador TODD C. COLLINS Todd Coll SIGNATURE March 24/16 DATE NEWFOUNDLAND & LABRADOR	Electrical
	Mechanical
	Civil
	Protection & Control
	Transmission & Distribution
	Telecontrol
	System Planning

Units 1 and 2 Boilers Lower Reheater Tube Replacement And Reliability Improvements

Holyrood Thermal Generating Station

March 2016

newfoundland labrador hydro
a nalcor energy company

SUMMARY

The Holyrood Thermal Generating Station (Holyrood TGS) was constructed in two stages. Stage 1, Units 1 and 2, was completed in 1970. Construction of the Stage 2 extension followed in 1979 and contains generating Unit 3.

This Capital Budget Supplemental application is requesting the approval of a project to improve reliability and availability of the capacity of the Holyrood Thermal Generating Station (TGS). This one (1) year project is twofold:

1. to replace the lower reheater tubes that service the Units 1 and 2 boilers at Holyrood, and
2. additional reliability improvements consisting of critical equipment replacement and level 2 condition assessments.

The boiler tubes have been in service since the initial construction of Stage 1 and are now experiencing failures as they near the end of their service life as evidenced by failures in January and February 2016. Tube replacements is proposed to occur during the planned annual maintenance outages scheduled to commence in August of 2016 for Unit 1 and June of 2016 for Unit 2. The duration of work associated with tube replacements is approximately 6 weeks per unit and occurs concurrently with the annual maintenance outages.

Additionally, Hydro has recently reevaluated many system components and is proposing to include in this project additional reliability improvements to further enhance the availability and reliability of the Holyrood TGS post the 2016 annual outage. The additional reliability improvements are primarily replacement of end-of-life equipment as well as some level 2 condition assessments that will provide Hydro critical information on required areas for additional refurbishment.

The estimated cost of this project is $11.8 million.

Hydro requires that the Holyrood TGS continue to operate reliably to provide capacity and energy to Island Interconnected Customers until interconnection. To ensure the reliable operation of the facility, the proposed replacement of the Units 1 and 2 boilers lower reheater tubes, and the additional reliability improvement work is required.

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1. INTRODUCTION

In this Application, Hydro is proposing a project to improve reliability and availability of the Holyrood TGS. This project has two aspects. Primarily, Hydro proposes to replace lower reheater tubes in Units 1 and 2 boilers at Holyrood TGS. Holyrood TGS's boilers lower reheater tubes have been monitored annually since 2010. These tubes have recently experienced failures in the Unit 2 boiler during January 2016 and in the Unit 1 boiler during February 2016. Hydro is proposing to replace the remaining lower reheat tubes. Secondarily, Hydro proposes to 1) replace various system components that are at end of life and 2) to perform level 2 condition assessments. The project is proposed to occur during the 2016 planned maintenance outages to ensure winter peak demands are met reliably.

The Holyrood TGS consists of three oil fueled units having a combined generating capacity of 490 MW. Units 1, 2, and 3 were commissioned in 1969, 1970, and 1979, respectively. Holyrood is an essential part of the Island Interconnected System. The station has the capability of generating approximately 40 percent of the Island Interconnected System's annual energy requirements.

1.1 Boiler Lower Reheater Tubes Description

The four main components of each generating unit are the boiler, steam turbine, generator and transformer. The main components of a boiler are water wall tubes, boiler drum, superheater, reheater, and economizer. A cross section of the boiler is shown in Figure 1. The primary function of the reheater is to increase the final temperature of the superheated steam which is fed to the intermediate and low pressure turbine sections. Steam is contained inside the tubes and the gases from the boiler fire pass over the tubes and transfer heat energy to the tube which transfers heat energy to the steam.

The lower reheater section in the boilers on Units 1 and 2 consists of three rows of tubes that span 62 tubes across the width (west to east) for a total of 186 tubes. Since the reheater operates at a lower pressure relative to other boiler components, reheater tubes have thinner walls. Corrosion in a tube can have a greater impact on the integrity of a thinner tube wall. Additional details on the reheater sections are also shown below in Figure 2.

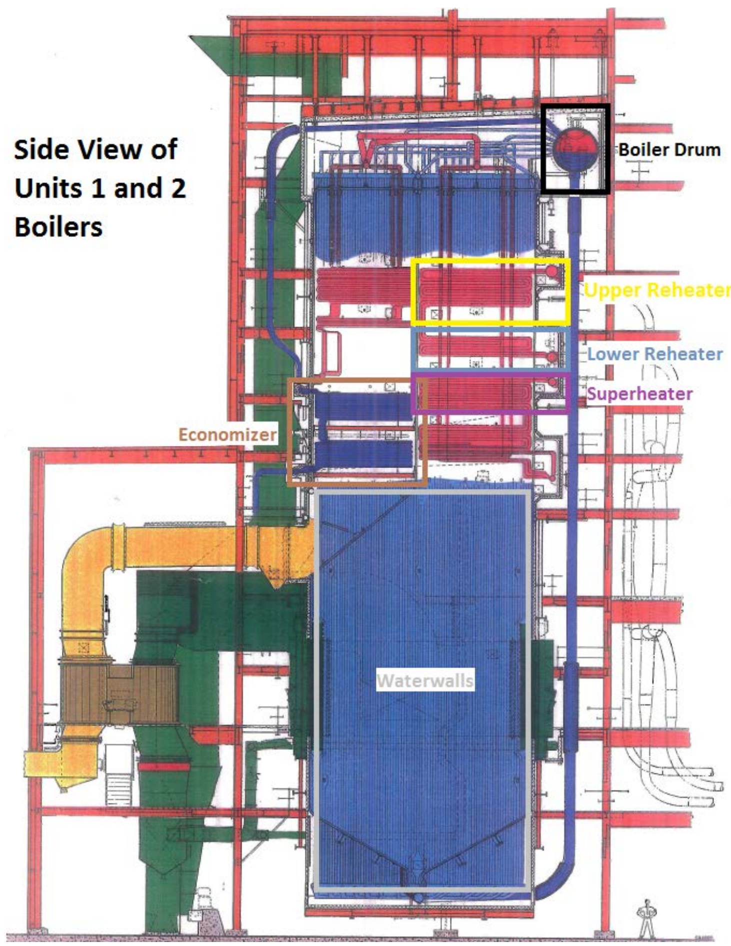

Figure 1: Boiler Elevation Showing Reheater Section

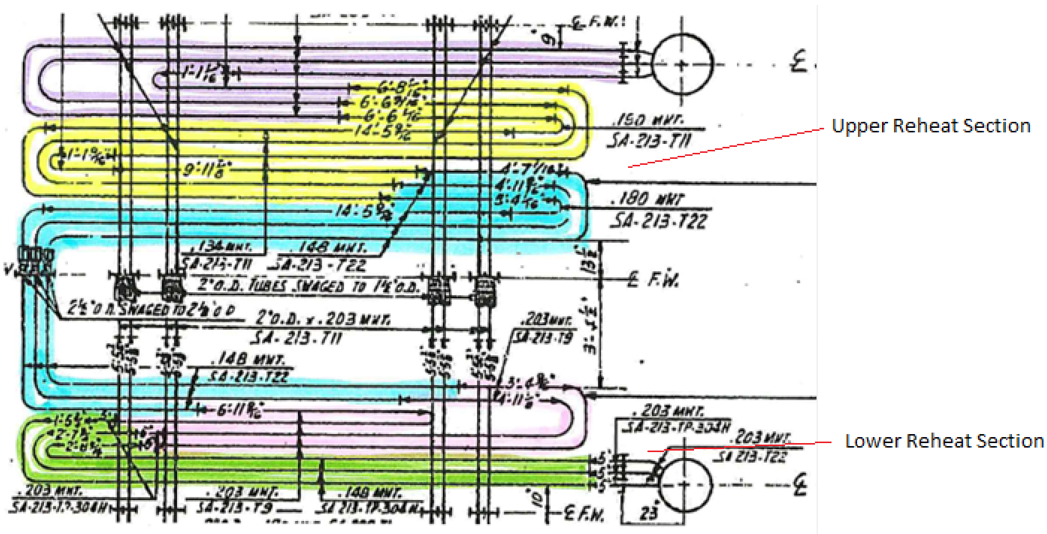

Figure 2: Reheater Details

1.2 Winter 2016 Boiler Reheat Tube Failure

On January 6, 2016, while operating at 165 MW, Unit 2 experienced a tube failure in the lower reheater section of the boiler. Upon discovery of the tube failure, Unit 2 was taken offline in a controlled shutdown and cooled to allow for internal inspection. As the boiler operates at very high temperatures, it takes approximately 36 hours to cool the unit sufficiently to allow for safe entry into the boiler to conduct the inspection. Upon completing the inspection overnight on January 7, four tube failures in the lower reheat section of the boiler and three tube leaks in the upper reheat section of the boiler were identified. To prepare for the anticipated tube replacement, all required resources and materials were mobilized on January 7 during the unit cooldown period. As such, once the inspection was completed and the scope of the replacements was defined, work on Unit 2 was able to begin immediately. Crews worked 24 hours a day, seven days a week to complete the tube replacements and the work was completed on January 14, 2016.

As is common practice when returning the unit to service, a stepped approach to loading the unit was employed. Between January 15 and January 19, the unit was gradually loaded in steps between 70 MW and 140 MW. On January 19, 2016, while operating at 140 MW, Unit 2 experienced another tube failure in the reheat section of the boiler.

The Unit was again taken offline in a controlled fashion and cooled to allow for access and inspection. Upon completing the inspection overnight on January 20, one tube failure in the lower reheat section of the boiler was identified. Considering the possibility of further failures and a favorable long term weather forecast, it was decided to replace as many of the lowest wall thickness tubes as the favorable weather window would permit. Taking advantage of the already mobilized and experienced work crew, the favorable weather window, and available materials, over the period since the unit first went out of service January 6, 2016, 27 lower and three upper reheat tubes were replaced prior to the unit going back in service February 3, 2016.[1]

An assessment was completed of the remaining tubes, and it has been determined the most prudent operating level for Unit 2 until additional lower reheat tubes can be replaced is 120 MW. This operational protocol of de-rating the unit is reasonable and necessary to preserve the integrity of the remaining reheat tubes prior to replacement.

On February 8, 2016, Unit 1 experienced a failure in the boiler lower reheater section. Unit cool down, inspection and tube replacement followed the same process as that described above for Unit 2. Tube replacements were completed during one outage. At the end of the outage, sixteen reheater tubes were replaced by February 26. Following a similar assessment and determination for Unit 1 as was completed for Unit 2, Unit 1 has also been de-rated to 120 MW and will continue to operate at that load until additional replacement of tubes in the lower reheater section is completed and the risk of an unplanned outage due to failed lower reheater tubes is mitigated.

[1] All Unit 1 and Unit 2 tube replacement work completed in January and February was completed under Allowance for Unforeseen Expenditures. All project close out activities are now complete and the report on this project will be submitted to the Board before March 31, 2016.

2. PROJECT DESCRIPTION

2.1 Boiler Lower Reheat Tube Replacement

The primary scope of this project includes the replacement of tubing in the lower sections of the boiler reheaters servicing Units 1 and 2, proposed to take place during the annual unit outages in 2016. Completing this work in 2016 allows for the units to be placed back in service prior to the winter period at higher capacity than the current maximum loading of 120 MW.

The tubes to be replaced are highlighted in green in Figure 2. The project includes procurement, installation, testing and commissioning of new boiler tubes. Additional work will be required such as replacing the front wall reheater header vestibule refractory seal, membrane and seal plates, as these items must be removed to facilitate the reheater tube replacements. Reheater tubes that were replaced during the Unit 1 and 2 forced outages in January and February 2016 will not require replacement under this project.

Tube replacements will occur concurrent with the planned annual maintenance outages scheduled to commence in June 2016 for Unit 2 and August 2016 for Unit 1. The duration of work associated with the tube replacements is approximately six (6) weeks per unit.

2.2 Equipment Replacement and Condition Assessments

The secondary aspect of this project is additional proposed reliability improvements for the Holyrood TGS. This comprises of replacement of end of life equipment, including valve and piping replacements, No. 2 air compressor replacement, pump replacements, and heat exchanger replacements, as well as condition assessments, including feedwater piping. Completing this work will reduce risk of unplanned equipment failure for equipment that is at or near end of life, thereby improving plant availability and unit capacity until interconnection.

3. JUSTIFICATION

3.1 Boiler Reheat Tube Replacement

Holyrood TGS is critical to Hydro providing reliable electrical service to customers. The primary aspect of this project is to replace the lower reheat tubes of for the boilers serving Units 1 and 2. The lower reheater section of the boiler must be functional to sustain operation and output of the generating unit. Based on the reheater tube failures that occurred on Units 1 and 2 in January and February 2016, replacement of the boiler lower reheater tubes must be completed to ensure reliable operation.

Hydro has proactively monitored tube thicknesses through condition assessments. Since 2010, Ultrasonic thickness (UT) measurements have been completed in the lower reheat section during scheduled annual outages. UT measurements had indicated tube wall thinning in several areas along the bottom row of the lower reheat section.

Tube thinning is normal and expected in the tubes of the lower reheater section. Due to their location, they are exposed to higher boiler temperatures as compared to the upper reheat tubes. Until winter 2016, Hydro had not experienced a tube failure in the lower reheat section. However, knowing the tubes were thinning, as can be expected, Hydro evaluated the risk of failure against the option of replacements and considered the following as part of the risk evaluation:

1. <u>Personnel Safety</u>: Personnel safety is not a concern with respect to failure of reheat tubes. The reheat tubes are internal to the boiler and any tube failures would be confined to the inside of the boiler.
2. <u>Trip of the Unit</u>: Failure of reheat tubes does not cause a trip of the unit. The unit can be operated after a tube failure and it can be taken offline in a controlled fashion.
3. <u>Equipment Safety</u>: The potential for collateral equipment damage is low with respect to failure of reheat tubes. The primary risk would be damage to adjacent

reheat tubes from impingement of superheated steam from a failed tube. This risk is mitigated by taking the unit offline in a controlled fashion after a tube failure is detected and experienced.

4. Operational Experience: The reheat section of the boiler has performed reliably over the life of the generating station (since 1970) and there have been no forced unit outages caused by the lower reheat section prior to January 2016. In addition, the reheater is operated at temperatures and pressures less than original design. Vendor recommendations suggest owners own operational experience of failures is important for deciding to replace tubes.
5. Maintenance Strategy: Hydro procured additional replacement materials for use in the event of a tube failure, and also ensured a continued monitoring and testing regime for tube wall thickness.
6. Reheater End of Life: It was originally anticipated that the reheater end of life would coincide closely with interconnection.

It is normal practice to make decisions regarding the priority of maintenance work required on the units and throughout Holyrood TGS. It was determined that, because failed tubes can be replaced safely and in a planned fashion once the issue has come to a critical point, without a sudden, damaging unit trip, the decision was made to commence replacement work when Hydro began to see tube failures. Hydro deemed it could continue to operate the units while monitoring the condition of the reheater tubes rather than replace all of the lower reheat tubes. The intent was to avoid the cost associated with replacing the reheater tubes and instead place priority on other equipment/elements that had higher safety and operational significance. As noted, Hydro procured replacement materials for use in the event of a failure of a lower reheater tube, which would allow for a reduced outage time in the event of a failure.

Figure 3: Failed Reheater Tube in Unit 2

Figure 4: Failed Reheater Tube in Unit 2

3.2 Equipment Replacement and Condition Assessments

In light of the recent tube failures, Hydro has, in the last two months, re-evaluated a number of aspects of systems for potential equipment areas at risk of failure. As an outcome of this reevaluation, Hydro is now proposing the secondary aspect of this project, which is to replace various equipment, including but not limited to valves, replacement of piping, coolers, and an air compressor for the various units. Also, Hydro will complete several level 2 condition assessments for critical equipment, to gain the information necessary that allows for planning of required refurbishment to maintain plant capacity and energy output. The proposed condition assessments on targeted boiler systems have been recommended by AMEC Foster Wheeler (AMEC) and are required for safe and reliable operation of Holyrood and the planning of future work.

Hydro could wait to incorporate this whole project into the next capital budgeting cycle, but Hydro views it appropriate to proceed as proposed this year as it is important to complete this work now to mitigate the risk of unplanned outages in winter 2016/17.

3.3 Existing System

3.3.1 Boiler Reheat Tubes

Steam from the exhaust side of the high pressure stage of the turbine flows through the reheater and is returned to the intermediate pressure stage of the turbine. The primary purpose of the reheater is to increase the temperature of the steam going to the turbine and increase the overall efficiency of the unit.

The reheat section consists of:

- 62 platens (group of tubes in common plane) that are oriented west to east across the boiler;
- Each platen consists of 3 tubes that make 7 bending passes between an upper and lower header;
- The reheat section is further divided into the ‘upper’ and ‘lower’ reheat sections;
- Original tube diameters vary between 2.5” and 2.125” with wall thicknesses between 0.203” to 0.148”;
- Tube materials also vary between the upper and lower sections of the reheater.

The area of focus for this project is the lower reheat section, which is subject to higher boiler temperatures. The tubes that are to be replaced include the lower bends and straight sections that are highlighted in green in Figure 2 above.

Hydro had previously engaged its boiler maintenance contractor, B&W, and Original Equipment Manufacturer (OEM), Alstom, to perform assessments to determine the cause of the lower reheater tube thinning.

Alstom suggested that the lower reheater tubes were experiencing external corrosion wastage due to oil ash corrosion, a normal and expected condition for boiler tubes at this age of service when burning heavy fuel oil. In oil fired boilers, the principal wastage of pressure parts is when low melting ash deposits lead to corrosion of superheater and reheater tubes (Plumley, Burnett, & Vaidya, 1982). Oil ash corrosion occurs when low melting constituents in the heavy fuel oil (vanadium, sodium and sulphur) deposit on a tube combined with temperatures where the tube surfaces exceed 1100^{O}F (Plumley, Burnett, & Vaidya, 1982). The oil ash corrosion experienced in the Unit 1 and 2 lower reheaters is the same corrosion experienced in Unit 1 and 2 superheaters. The Unit 1 and 2 superheaters were replaced in 2007 and 2008.

B&W advised Hydro that additional thinning in the lower reheater tubes in both Unit 1 and 2 is due to out-of-service corrosion. Out-of-service internal corrosion damage is caused by dissolved oxygen pitting. Corrosion damage, due to dissolved oxygen attack, can occur on any wetted internal surface and is usually more severe at the water-air interfaces. When a boiler is taken offline, condensate can form and accumulate in low areas (e.g. sagging tubes) in the lower reheater. By the nature of the design, the lower reheater tubes are non-drainable (Babcock & Wilcox Power Generation Group, 1989).

Operational measures have been established for operating the unit until the next scheduled maintenance outage when additional tube replacements are being planned, pending Board approval. These operational measures will minimize the stresses on the reheat tubes, which will help mitigate further tube failures. They include maintaining the load on the unit at a constant level and not exceeding 120MW. Accordingly, the hot reheat temperature will be operated at 460 C, which is below the design temperature of 538 C.

3.3.2 Equipment Replacement and Condition Assessments

As mentioned above, the secondary aspect of this project is to replace equipment, such as valves, piping, coolers, and an air compressor within the plant. The replacements are required due to age, and condition assessment that indicates the various components could be at risk of failure. Replacements will include the following:

1. <u>The steam coil air heaters (SCAH's) that service Unit 1</u>. SCAH's function is to heat the combustion air prior to entering the boiler. If the SCAH is out of service, there is a loss of efficiency as well a risk of increased corrosion. Further, due to damage on the SCAH fins, there is potential impact on Unit 1 output due to some air flow reduction.
2. <u>Failed suction heat exchanger on Fuel Oil Storage Tank No. 3</u>. The suction heat exchanger function is to heat the No.6 fuel oil prior to entering the plant fuel oil distribution piping. When a heat exchanger is failed, it is more difficult for fuel to flow from storage and into the plant. Further, a failed exchanger is at higher risk of leaking into the environment.
3. <u>Expansion joints on the Unit 1 boiler downcomer piping and the Unit 2 reheater tubing header.</u> These expansion joints complete the gas seal between the boiler casing and the downcomer pipes and boiler headers. Failure of these joints allows boiler gas to escape into the plant and becomes a health and safety issue.
4. <u>Unit 1 DC lube oil pump motor starter.</u> The DC lube oil pump is a back-up pump that provides lubrication oil to the turbine and generator bearings in the event of a failure of the main AC lubrication oil pumps. The existing motor starter, while functional, is now considered obsolete and requires replacement.
5. <u>Unit 2 reheater pressure safety valve (PSV).</u> The reheater PSV provides mechanical

protection to the boiler reheater tubes during a high pressure situation. This valve is currently not working as required, and must be replaced.

6. <u>Failed insulation and cladding around the bottom levels of the Unit 3 boiler identified during the 2016 operating season.</u> Failed insulation and cladding is a safety risk for employees and also a source of heat loss for the boiler, and therefore an efficiency requirement.
7. <u>Unit 3 boiler's West fuel oil pump</u>. The existing system includes a redundant fuel oil pump, and Hydro maintains a spare as well. Recently, one of the in service pumps failed, and the spare was utilized. Hydro proposes to replace this critical spare in this project.
8. <u>Replacement of No.2 air compressor which has reached its end of life and is currently out of service.</u> No.2 air compressor is one of three (3) air compressors which provide compressed air to the plant's various compressed air systems. Hydro has been utilizing a rental air compressor on a short term basis until a new compressor could be applied for and procured.
9. <u>Replacement of a sensor cable on the continuous emissions monitoring system (CEMS) servicing Unit 1.</u> This cable transmits flue gas sensor data from the stack to gas analyzing equipment. Condition assessment shows it needs to be replaced. If this cable fails while in service, Hydro would not be able to measure emissions for Unit 1.
10. While Hydro has not currently identified additional equipment for immediate replacement, it is possible an additional component may require replacement during the annual outages. Hydro proposes that any item, material in dollar value, that meets capitalization criteria, is required to be replaced to mitigate an unplanned outage in the coming winter season, and that can be replaced within this project's contingency, would be replaced and communicated to the Board via the year end Capital Expenditures Variance report.

In addition to the above noted equipment which requires replacement, Hydro is proposing to complete several Level 2 condition assessments for critical equipment, to gain the information necessary to plan any necessary refurbishment. This is required to maintain plant capacity and output. The specific system components to be assessed were determined by AMEC. In particular, AMEC focused on equipment that is susceptible to flow accelerated corrosion in the feedwater piping as this has a particular safety concern and unplanned failures can be dangerous for employees. The assessments will include the following equipment:

1. Unit 1 steam drum and downcomer piping;
2. Boiler superheater outlet header on Units 1, 2, and 3. The superheater outlet header connects the boiler tubing to the high pressure piping which conveys steam to the turbine;
3. High pressure steam piping external to the boiler on Unit 1;
4. Boiler feedwater piping on Units 1, 2, and 3. The boiler feedwater piping conveys water from the boiler feedwater pumps to the boiler;
5. Condenser water box on Units 1, 2, and 3. The condenser functions to condense steam after it exits the low pressure section of the turbine. The water box is the location where the cooling water enters and exits the condenser;
6. Internal assessment of the Unit 2 rotary air preheaters by the OEM. Air preheaters are heat exchangers that recover heat from the exiting boiler flue gas to heat the incoming boiler combustion air; and
7. Water wall tube bends around the burners and lower levels of the Unit 3 boiler.

3.4 Operating Experience

3.4.1 Boiler Reheat Tubes

Originally rated for 150 MW, Units 1 and 2 were placed in service in 1969 and 1970, respectively, and were upgraded to 170MW in 1988 and 1989. The OEM for both units is Alstom. As of February 2016, Unit 1 has an approximate total operating hours in excess of 193,000, Unit 2 has an approximate total operating hours in excess of 186,000, and Unit 3 has an approximate total operating hours in excess of 149,000.

On January 6, 2016, while operating at 165MW, Unit 2 experienced tube failures. Access to the repair location was challenging due to space constraints as shown in Figures 5 and 6. Tubes were replaced and the unit went back in service through a stepped approach. While going through the stepped return to service, another failure occurred. The unit was again removed from service for additional tube replacements.

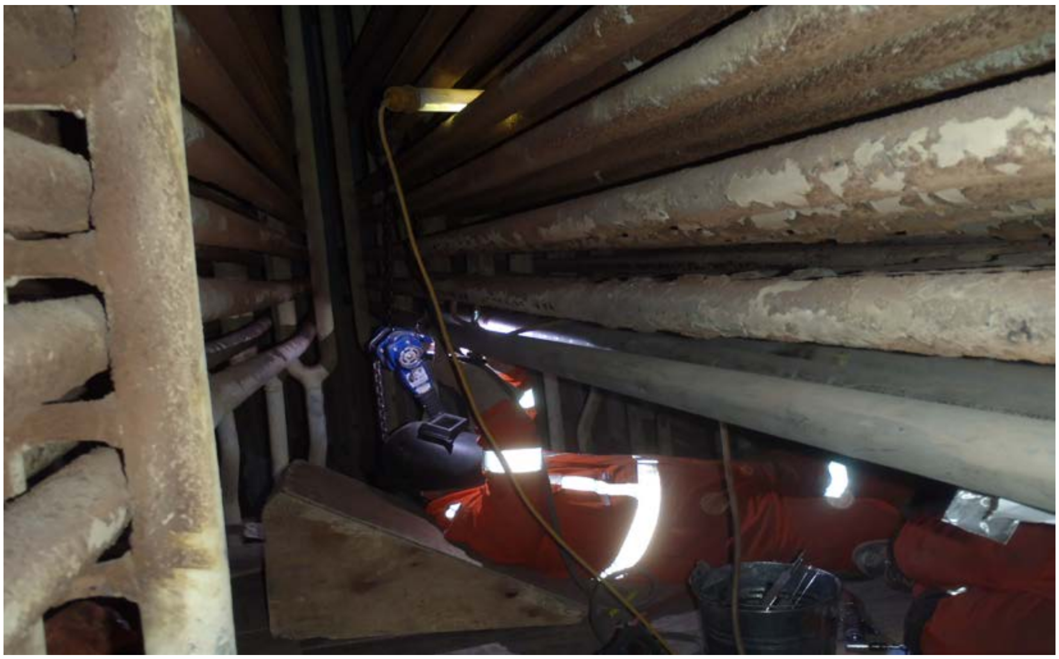

Figure 5: Welding Repair in Lower Reheater

Figure 6: Access Hatch to Reheater

On February 7, 2016, Unit 1 experienced a failure in the boiler lower reheater section. As Unit 2 had just been returned to service, Hydro deemed it appropriate to wait for a period of time before taking Unit 1 out of service, to allow for Unit 2 to demonstrate it would be remain in service following the tube replacement work. Hydro assessed unit 1 and was able to temporarily manage Unit 1 to a derated output, as was Hydro's plan should failures occur. Prior to Unit 1 coming out of service, Unit 1 was held at a maximum of 50 MW for the period until February 16, 2016, when it was determined Unit 2 was stable following the replacements of Unit 2's most critical boiler tubes. After February 16, 2016, replacement of sixteen tubes on Unit 1 was completed and the unit was returned to service on February 26, 2016. Since the Unit 1 tube replacements, the unit has been de-rated to 120 MW and will continue to operate at that maximum load until the replacement of the tubes in the lower reheater section is completed.

3.4.2 Equipment Replacement and Condition Assessments

Following many years of operation, it is normal for various equipment components, especially high pressure piping components, to deteriorate. Level 2 condition assessments and replacements are necessary to ensure reliable operation of critical plant systems. A listing of plant systems and equipment requiring replacement and Level 2 condition assessment is provided above in Section 3.3.2. Replacement of aged or faulty equipment mitigates risk of operational issues during high demand periods.

3.5 Reliability Performance

There were no forced outages caused by lower reheater tube failures prior to January 2016. As previously discussed, the unplanned tube failures in Unit 1 and 2 impacted the plant output for the period the tube replacements were ongoing. Further, Units 1 and 2 are currently de-rated until additional tube replacements can occur. As well, in the case of Unit 1, a tube failure was allowed to stay in service until the unit could be removed from service, but the plant's output was reduced during the period.

Other equipment being contemplated for replacement and condition assessment in this project can impact safety, efficiency, availability and/or reliability of the plant. For example, the steam coil air heater on Unit 1 that is currently damaged can restrict the air flow to Unit 1, and therefore impact its output.

Table 1 below shows the outage statistics for Holyrood TGS as well as the latest average statistics as reported by the Canadian Electrical Association (CEA). Incapability Factor is defined as unit unavailable time. It is the ratio of the unit's available time to the total number of unit hours. DAFOR is defined as Derated Adjusted Forced Outage Rate and is the ratio of equivalent forced outage time to equivalent forced outage time plus the total equivalent operating time. Failure Rate is defined as the rate at which the generating unit encounters a forced outage. It is calculated by dividing the number of transitions from an Operating state to a forced outage by the total operating time.

Table 1: Holyrood TGS Unit Performance

Five Year Average 2010-2014	All Causes		
Unit	Incapability Factor (%)	DAFOR [2](%)	Failure Rate
Holyrood Unit 1	39.00	26.29	8.05
Holyrood Unit 2	25.32	5.09	9.29
Holyrood Unit 3	40.41	9.35	7.15
Holyrood Plant	34.91	11.14	8.26
CEA (2010-2014)	26.33	13.14	7.79

3.6 Legislative or Regulatory Requirements

The physical condition of a steam boiler operating in the province of Newfoundland and Labrador is governed by the *Boiler, Pressure Vessel, and Compressed Gas Regulation* under the provincial *Public Safety Act*. Operating a boiler with a tube leak is not contrary to this legislation. A provincial boiler inspector is notified when a leak is identified.

3.7 Safety Performance

Safety non-compliance is not an issue for failures of tubes in the reheater. This portion of the boiler circuit is internal to the boiler. If a failure of a tube in the reheater was to occur, it would be confined to the inside of the boiler and the boiler can be shut down in a controlled, safe manner.

A portion of the additional reliability improvement work proposed does pose safety risks to plant equipment and personnel in the event of a failure. For example, the condition assessments proposed to be completed as part of this project are for the feedwater piping which, if an unplanned failure occurs, can be very dangerous for employees to be in the

[2] Hydro reports on the 12 month rolling average DAFOR for Holyrood TGS. In the most recent filing on January 14, 2016, for the 12 month period ending December 2015, the "all Thermal units weighted" DAFOR was 5.04%. This number did not take into account the availability issues of January and February 2016. The next 12 month rolling generation report to be mid April, 2016, will contain this data.

vicinity. The condition assessments will produce information on what sections of piping need replacement in order to remain safe for employees and keep the unit operational.

Hydro notes that, for the planned replacement work, there are direct safety related outcomes for some projects:

1. Units 1 and 2 expansion joint replacements on the downcomers and reheat headers. Failure of these expansion joints will allow boiler flue gas to enter the plant, which is an Occupational Health and Safety (OHS) risk for employees.
2. Replacement of boiler refractory around the Unit 2 boiler superheater. Failure of this refractory will also allow boiler flue gas to enter the plant which is an OHS issue for employees.

3.8 Environmental Performance

Environmental non-compliance is not an issue for tube failure in the reheater section of the boiler. However, several of the proposed equipment replacements have the potential to cause environmental non-compliance if not completed. These items include the following:

1. Unit 1 CEMS cable replacement. If this cable fails in service, Hydro will not be able to monitor emissions.
2. Replacement of Fuel Oil Storage Tank No.3 suction heaters. Failure of the suction heaters can allow the No.6 fuel oil to enter the steam system which can have an environmental impact, or if the heat exchanger fails catastrophically, fuel can leak into the environment.

3.9 Industry Experience

As noted above, Hydro had previously engaged its boiler maintenance contractor, B&W, and OEM, Alstom, to perform assessments to determine the cause of the lower reheater tube thinning. Two causes which were identified include oil ash corrosion and out-of-service corrosion

For the other components of this project, such as high pressure piping, over time, these components are subject to failure mechanisms such as corrosion, flow accelerated corrosion (FAC), creep, and fatigue. It is normal to replace equipment at end of life or when equipment is no longer functioning as expected, as is the case with the equipment being replaced. Further, it is also normal to complete detailed condition assessments to determine the most critical work required to keep units running safely and efficiently.

3.10 Vendor Recommendations

Internal inspection and service reports were completed by Alstom in 2010/2011. These reports recommended monitoring the corrosion of the lower reheater sections and budgeting for a replacement in the future. Hydro followed this recommendation.

The proposed condition assessments on targeted boiler systems were recommended by AMEC during the Level 2 condition assessment program, completed from 2012 to 2015, and are required for safe reliable operation of the Holyrood TGS and the planning of future work. The AMEC Level 2 Condition Assessment reports are included in Appendix A.

3.11 Maintenance or Support Arrangements

From 1997 until 2011, Alstom provided Hydro with maintenance services for the three boilers. As of April 2012, B&W has been providing Hydro with maintenance services for all three boilers. Hydro also maintains a turbine generator service contract and other various service contracts for balance of plant equipment.

3.12 Maintenance History

The maintenance history for the Units 1 and 2 reheaters is shown below in Tables 2 and 3 respectively:

Table 2 – Unit 1 Reheater Maintenance History:

Year	Preventative Maintenance ($000)	Corrective Maintenance ($000)	Total Maintenance ($000)
2015	5	0	5
2014	5	0	5
2013	25	0	25
2012	5	0	5
2011	5	0	5

Table 3 – Unit 2 Reheater Maintenance History:

Year	Preventative Maintenance ($000)	Corrective Maintenance ($000)	Total Maintenance ($000)
2015	5	0	5
2014	5	0	5
2013	25	0	25
2012	15	0	15
2011	5	0	5

The equipment proposed for replacement and for condition assessment is a number of small to medium size plant components. Much of the maintenance history at the plant is not captured and reportable by small component size. Hydro does note that all components are maintained as part of various comprehensive plant preventative maintenance work orders and corrective maintenance is completed as required.

3.13 Anticipated Useful Life

The replacement tubes for Unit 1 and 2 boilers lower reheater sections and the majority of the replaced equipment is expected to last well beyond interconnection, and until a determination has been made for when Units 1 and 2 are no longer required for generation.

4. DEVELOPMENT OF ALTERNATIVES

The alternative to completing this project now is to not replace any equipment, including the boiler tubes, and instead replace upon failure.

However, now that Hydro has experienced tube failure history since winter 2016, it is appropriate to replace the remaining lower reheater boiler tubes in advance of the next winter. Further, Hydro has reevaluated various system components and identified components for replacement to mitigate risk of uninterrupted service of the Holyrood TGS in the next high demand operating season. In Hydro's view, to not complete this project during the scheduled maintenance outage period in June and August 2016, now that new operating history has developed, is not appropriate. Hydro deems it is prudent to proceed with this work in 2016 in order to increase capacity above the units current derated output.

Another alternative is to delay this work until 2017 and include the work as part of the 2017 Capital Budget cycle. Hydro does not consider this to be an acceptable alternative considering the derate that occurred during the last winter season, which was a cumulative de-rate of 100 MW for Units 1 and 2. Should additional failures occur in winter 2016/17 before an approved 2017 Capital budget project is approved and executed, the units would see some level of unit unavailability or potential de-rate. Further, a potential derate or unavailability that could occur with a tube failure does not consider any operational or availability issues that could occur if the additional equipment is not replaced or the condition assessments are not completed.

5. EXECUTION

This project is expected to cost approximately $11.8 and will take eight (8) months to complete.

5.1 Budget Estimate

Table 4: Project Budget Estimate

Project Cost:*($ x1,000)*	**2016**	**2017**	**Beyond**	**Total**
Material Supply	479.0	0.0	0.0	479.0
Labour	300.0	0.0	0.0	300.0
Consultant	120.0	0.0	0.0	120.0
Contract Work	8,305.0	0.0	0.0	8,305.0
Other Direct Costs	0.0	0.0	0.0	0.0
Interest and Escalation	709.5	0.0	0.0	709.5
Contingency	1,840.8	0.0	0.0	1,840.8
TOTAL	**11,754.3**	**0.0**	**0.0**	**11,754.3**

5.2 Project Schedule

Table 5: Project Milestones

Activity		**Start Date**	**End Date**
Planning	- Identify and order materials - Issue PO to contractor	April 2016	April 2016
Procurement	- Materials arrive on site	April 2016	June 2016
Construction	- Remove existing reheater tubing - Install new reheater tubing -Equipment replacements -Condition Assessments	June 2016	Oct. 2016
Commissioning	- NDE new tube welds - Startup pressure report	July. 2016	Oct. 2016
Closeout	- Project close out and hand over documents	Nov. 2016	Dec. 2016

Hydro notes that Units 1 and 2 are already undergoing an annual unit maintenance outage in 2016, as per normal maintenance cycles. The work described in this proposal would take place concurrently with the maintenance outage already planned.

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Holyrood Thermal Generating Station Condition Assessment and Life Extension Study –Phase 2

2012/13 Level II Condition Assessment Boiler and High-Energy Piping

AM132/RP/005 R03

Nov 13, 2013

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Revision Summary

Rev	Date	Author	Comments
R00	November 2012	D. McNabb	Initial Issue
R01	February 2013	D. McNabb	Revised for: • Additional creep information • Steam piping hanger inspections • Address client feedback
R02	August 2013	D. McNabb	Revised for the 2013 inspections including: • Unit 1 boiler inspections • Unit 1 high energy steam piping inspections • Completion of the Unit 3 hot hanger inspections • Follow-up on hanger issues identified in the 2012 inspection campaign
R03	November 2013	D. McNabb	Revised to address: • Client feedback • Issue of the final replica report • Developments since R02 issue o Removal of RH DMW sampling o Cancellation of the Unit 2 outage in 2013 o Request for Stage 1 Hot Reheat thickness data

Executive Summary

The Holyrood Thermal Generating Station (Holyrood TGS) consists of three oil-fired generating units with a total nominal generating capacity of 500MW. The units were built in two stages with Stage 1 (Units 1 and 2) being placed in service in 1969/70 and Stage 2 (Unit 3) placed in service in 1979.

Nalcor has a requirement for the Holyrood Thermal Generating Station to operate reliably to 2020 as a generating facility, and for Unit 3 to continue operation as a synchronous condenser to 2041. This is beyond the nominal design life of the units, of approximately 30 years. The condition assessment and life extension project was initiated to assess the remaining life of the generating units and the related station infrastructure, and to identify actions to assure the desired life could be achieved with acceptable reliability. Phase 1 of the project, consisting of a Level I condition assessment was completed by AMEC in 2011.

AMEC was engaged in 2012 and 2013 to conduct a Level II condition assessment, based on the priorities identified in the Level I assessment. The inspection on Unit 1 in 2013 also had the purpose of evaluating whether damage was incurred on the Unit 1 steam piping during a turbine excursion in January 2013.

The focus for 2012 was to be major boiler components and high-energy piping, including the pipe support systems for all three units. Due to time restrictions, only a limited scope of work was completed on Unit 2 in 2012. Additional work was competed on Unit 1 in 2013, which included an assessment of the damage to steam piping from a turbine trip event on Unit 1 in January 2013. The boiler was not considered affected by the trip event due to the length and flexibility of the lines before encountering the boiler. The following report summarises the work completed, methods applied, results of the inspections and life assessment, and provides recommendations for further inspections and life management activities on target components.

Non-Destructive Examination (NDE) of select components was completed in October 2012 on Unit 2, and on Unit 1 in April 2013. Cold and hot steam piping hanger inspections were completed on Units 1 and 2 between September and December 2012. Unit 3 hangers were inspected in the cold condition only in 2012 and in the hot condition in April 2013.

The inspections identified the following in-service damage on Unit 2 and Unit 1:

- Weld cracking/creep in the secondary superheat outlet header nozzles.
- Thermal fatigue cracking in the steam drum at the downcomer nozzles.
- Cracking at the secondary superheater outlet header (SH6) stub tube welds, tube side.
- Isolated creep cavities were reported in the coarse grain heat affected zone (HAZ) of the main steam pipe weld at the west turbine flange weld.
- Creep damage in a low alloy weld pass on the Unit 1 Boiler Stop Valve (BSV) inlet weld.
- Flow Accelerated Corrosion (FAC) damage in the High Pressure (HP) feedwater piping down stream of the #4 feedwater heater.

Damage in the steam drum, the SH6 nozzles, and the SH6 stub tubes was removed on both units and repairs completed where necessary.

Steam drum thermal fatigue cracking at the downcomer penetrations is common in drums of this design and is managed through periodic inspection and analysis.

The SH6 nozzle weld cracking on Unit 2 was considered an original fabrication weld defect but was described as creep related on Unit 1. For the purpose of life management, the damage is treated as creep. Re-inspection of repaired areas on Units 1 and 2 is recommended within one year to ensure there is no re-initiation. Longer term monitoring for creep is also recommended. Specific guidance on inspection frequency is provided below.

The stub tube cracking is the result of fatigue, and is a reasonably common industry issue. Inspection of the reheat outlet header (RH2) on Unit 1 found no evidence of cracking, suggesting the issue is confined to the SH6 stub tubes. Evidence of creep voids in the course grained HAZ of the main steam weld at the west turbine flange weld are indicative of early stages of creep damage. Damage accumulation should be monitored by periodic inspection at periods defined below.

Creep damage in low alloy weld material on the Unit 1 BSV inlet weld is expected. The low alloy material is unusual and likely a construction error. The same is unlikely on Unit 2 given the valve and welds have been recently replaced. However, inspection of the valve inlet weld in 2013 is recommended after a failure in the above seat drain weld in early 2013.

The indication of FAC in the HP feedwater piping was expected. The double elbow downstream of the #4 feedwater heater is a susceptible location. Repair was not required due to the margin on minimum wall thickness. Reinspection at this location is recommended in 7 years (re-inspect in 2019). The same applies to Unit 1. It is highly recommended that a FAC management program be implemented.

There was also thermal fatigue damage identified in the economiser inlet headers on Units 1 and 2 in the 2010 boiler maintenance outage conducted by Alstom. It was concluded by Alstom that the headers were fit for service and reinspection was recommended within three years (by 2013) to monitor damage accumulation. Inspection of the Unit 3 economiser inlet header was only partially complete in 2010. No damage was found on Unit 3 but further investigation is recommended.

The assessment concluded that there are no life-limiting issues among the components inspected, and no major capital expenditure requirements were identified. There were also no immediate concerns from the Unit 1 turbine trip event other than repairs to the HR15 and HR17 supports. However, the issues identified need to be managed to achieve the desired safety and reliability performance. It must be noted that these conclusions are based on limited inspections and it should not be concluded that a full life assessment has been completed.

The recommendations below are based on results of the assessment in Section 5 and the risk assessment in Section 6. Actions are recommended at the earliest opportunity unless stated otherwise below.

1. The planned Phase 2 boiler and high-energy piping condition and life assessment scope of work needs to be completed– identified in Appendix A. The scope can be adjusted to account for the work completed in 2012 and 2013 inspection results and with consideration of the discussion in Section 5. The following specific items should be included:
    a. Unit 1 and 2 economizer inlet headers
    b. Unit 1 or 2 boiler superheat crossover piping
    c. Unit 1 or 2 SH4 girth weld and internal visual inspection

   d. Wall thickness measurements on either Unit 1 or 2 Hot Reheat 20” OD, and 16” OD Piping downstream of a combined stop valve (one side)
   e. Unit 3 Boiler scope (Appendix A), and:
      i. Inspection of the Unit 3 economiser link piping supports
      ii. Steam drum inspection
   f. Circumferential etch of the SH6, RH2 headers and the superheat link piping for evidence of a seam weld microstructure, on either Unit 1 or Unit 2

2. In addition to the life assessment scope identified above, it is recommended the specific locations listed below be inspected in 2013 as follow-up to the damage identified in 2012.
   a. Unit 2 SH6 header east and west outlet nozzles are to be inspected for surface defects in 2013 to confirm no recurring damage accumulation.

      Routine inspection of the SH6 nozzle welds for creep damage is to be conducted on each of Unit 1 and Unit 2 every 6 years, alternating between units (one unit every 3 years) starting on Unit 2 in 2015 (3 years from the 2012 inspection). The next inspection would be conducted in Unit 1 in 2018, or 2017 given the possible operating hours in present operating plan. The inspections are expected to include wall thickness measurements to detect any impacts of corrosion.
   b. Unit 2 main steam piping west turbine flange weld at 6 year intervals. The inspection methods are to include replica, PAUT and MPI, starting in 2015.
   c. A sample of riser tubes is to be inspected on either Unit 1 or2 to assess severity of pitting and potential axial cracking before 2015
   d. Re-inspect one of either the east or west Main Steam Valve (MSV) outlet welds, and Combined Stop Valve (CSV) outlet welds on Unit 1 every 3 years starting in 2016, for accelerated creep damage due to plastic strains created by the trip event. Consideration should be given to installing removable insulation on the selected locations to facilitate access to the welds.
   e. Repairs are required within one year at the Unit 1 Hot Reheat supports HR15 and HR17; concrete and mounting plate repairs at the base of stanchions and possible replacement of the stanchion.
   f. Periodic inspection of a downcomer nozzle inside the steam drum needs to be implemented. One end (one downcomer) every 3 years, alternating ends is recommended for both Units 1 and 2, starting with Unit 2 in 2015.
   g. Inspect the Boiler Stop Valve inlet weld on Unit 2 at the next available opportunity for evidence of creep damage

3. An engineering analysis to define critical crack size and growth rate is recommended for the Units 1 and 2 economiser inlet headers (one assessment covering both units) as a basis for continued operation without repair, and to define end of life. The need for a similar analysis for Unit 3 will depend on the inspection results recommended in Item 1.

4. A review of unit start operating practices is recommended to ensure measures to limit thermal cycles are being effectively implemented.

5. A review of unit lay-up practices is recommended to ensure measures to limit corrosion and pitting of boiler and piping components are being effectively implemented.
6. A FAC susceptibility analysis and management program consistent with industry practice is recommended to assess the full scope of FAC in the Holyrood units, to identify opportunities to mitigate damage accumulation, and to manage integrity implications. The susceptibility analysis can also include a review of cycle water chemistry control practices. The action needs to include monitoring of piping thinning in the superheat attemperator water supply piping at valve 2TV619C on Unit 2 in 2015.
7. A hanger inspection and high-energy steam piping management program is recommended to monitor damage accumulation in the piping and condition of the supports to manage steam piping performance over the desired remaining life of the units. The inspections would include wall thickness measurements to assess wall loss due to high temperature corrosion, in 2015. Additional specific actions are:
    a. Review and corrective action is recommended to address minor mechanical issues and to balance loads on the trapeze hangers.
    b. Monitor pipe hangers in the topped or bottomed out condition, or showing no movement. Conditions where multiple pipe hangers in a system are either topped or bottomed out should be considered for analysis to determine impact on the system piping stresses and load distribution, and on the other pipe hangers. In addition, manufacturer specifications for the pipe hanger should be consulted. Further details are provided in Appendix E.

It is also recommended that the results of the Level II assessment and life management strategies be integrated with the annual boiler and high-energy piping maintenance program. A new boiler maintenance program was developed by Alstom. A review and optimisation of the program to accommodate the results of the Level II assessment will help ensure desired performance is achieved. This action should also consider the effects of increased unit starts, and cycle water chemistry control performance. Periodic (3 year) removal of waterwall tube samples from high heat flux elevations needs to be part of the on-going boiler management program.

TABLE OF CONTENTS

1.0 INTRODUCTION

Nalcor Energy requires that the Holyrood Thermal Generating Station (HTGS) continue to operate as a generating station until 2020 and Unit 3 as a synchronous condensing facility until 2041. Operation to these dates will result in life extension beyond the original design lifetime of the station, approximately 30 years. Inspection and subsequent assessment of the results is required to identify components and/or systems, which will require remedial measures (maintenance, inspection and/or analysis) to allow the station to continue to operate with high reliability during the extended operating period.

In 2010, AMEC undertook a Level I Condition Assessment of the Holyrood Thermal Generating Station. As a part of this, AMEC NSS participated in the preparation of a Level I Condition Assessment for the boilers, high-energy piping and major pressure vessels to assess remaining life and potential degradation mechanisms that could adversely affect reliability over the target operating period. Design and historical operating and maintenance data were used as the basis for remaining life assessments. The resulting report included a background summary of industry issues and mechanisms, a summary of the HTGS assessment, a list of issues prioritized by risk to the generating plan (desired life), and an estimated cost for a Level II Condition Assessment of the subject components [R-1, R-2].

Phase 2 of the Holyrood Condition Assessment and Life Extension Study is a Level II assessment of the major issues identified in Phase 1. Revision 1 of this report provided a summary of the activities and findings for boiler and pressure piping inspections that were undertaken in 2012. The present report, Revision 2, incorporates boiler and pressure piping inspections conducted on Unit 1 and hanger inspections completed on Unit 3 in April 2013. The inspected plant systems were considered among the highest priority items from a safety and operational due diligence perspective for life extension. There was also a desire to investigate integrity implications for steam piping on Unit 1 resulting from a turbine event in January 2013. The Unit 1 boiler was considered by Nalcor as essentially unaffected by the turbine excursion, and no additional boiler scope was added.

1.1 General Description of Holyrood TGS Boiler and High-Energy Piping [R-3]

HTGS has three (3) residual fuel oil-fired units having a total combined output of 500 MW (nominally 150 to 175 MW units). General information on the generating units was provided as follows:

1. Units 1 & 2 are duplicate, 1970 vintage type units: originally rated at 150 MW; having oil-fired boilers, originally built by Combustion Engineering (now represented by Alstom).
2. Both Units 1 and 2 boilers were designed to generate a main steam (MS) flow rate of 1,050,000 lb/hr at an outlet temperature and pressure of 1005 ^{o}F & 1900 psig respectively.
3. Units 1 & 2 were modified from their original design in 1987 by Alstom to produce 175 MW per unit with a revised main steam flow rate of 1,167,000 lb/hr at an outlet temperature & pressure of 1005 ^{o}F & 1955 psig respectively.

4. Unit 3 is a 1980 vintage type unit: rated at 150 MW; having an oil-fired boiler originally designed and built by Babcock & Wilcox.
5. Unit 3 has a main steam flow rate of 1,072,000 lb/hr at an outlet temperature & pressure of 1005 ^{o}F & 1890 psig respectively.
6. Unit 3 was modified in 1986 to permit the generator to be decoupled from the steam turbine for operation as a synchronous condenser (SC).
7. Typically, the plant operates seasonally base-loaded between December and March, but on a daily load cycling basis with each unit running between 70 MW & full load. Full plant capacity is currently needed to meet the winter electrical requirements of the Island Interconnected System. For much of the rest of the year, generation from some or all of the units is not required. Often during the summer when customer demand is at its lowest, no generation is required but Unit 3 is required to operate as a synchronous condenser for system stability purposes.
8. As of May 9, 2013, the operating hours for each unit are as follows [R-24]:

Unit 1	181,571 hrs
Unit 2	173,254 hrs
Unit 3	136,441 hrs
Unit 3 (as a synchronous condenser)	47,603 hrs

9. The existing fuel system includes the following:
   - A heated delivery pipeline, approximately 0.75 km long from the ship to the tank farm.
   - Four (4) 220,000 barrel (bbl) main fuel oil storage tanks, which are un-insulated and unheated with the exception of the suction heaters.
   - A gravity flow pipeline between the main fuel oil storage tanks discharges to a common 4000 bbl day tank.
   - A common 4,000 bbl day tank, which supplies fuel skids for each of the three (3) units.
10. Each boiler is equipped with two (2) forced draft fans and uses both regenerative air pre-heaters and steam coil air heaters prior to combustion.
11. Flue gases are discharged into a single stack for each boiler. Each stack is located immediately north of the main building.
12. All three generating units are controlled remotely through a Foxboro DCS system.

The following is a list of major equipment upgrades that have been completed:

Major Upgrades	**Year**
• Upgrade Unit 3 to operate as a synchronous condenser as mentioned in Item #6 above	1986
• Up-rate Generation Units 1 and 2 (150 MW to 175 MW) as mentioned in Item #3 above	1987
• Replace Boilers Breeching	1990
• Upgrade Boiler Air Pre-heater Steam Heat Exchanger	1990
• Replace Roof and Upgrade Siding	1990-2000
• Construct New Water Treatment Plant	1992
• Install Warm Air Make-up System	1992
• Construct five Ambient Air Monitoring Stations	1993
• Construct New Wastewater Treatment Plant	1994
• Install Boiler Soot Blower	1995
• Replace Unit 1 Boiler Stack Liner	2000
• Replace Uninterrupted Power System	2000
• Remove/upgrade reheater tube surface from Unit 3	2001
• Replace Unit 2 Boiler Stack Liner	2001
• Upgrade Unit 1 and 2 Exciter	2002
• Upgrade Units 1, 2, and 3 Controls System	2002-2003
• Replace Heating, Ventilation & Air Conditioning Units	2002-2005
• Upgrade Unit 1 and 2 Governor Controls	2003
• Install Continuous Emissions Monitoring System (shared)	2003
• Plant Asbestos Removal Program (3 year project)	2003-2006
• Construct New Security Building	2004
• Replace Boiler No. 2 Partial Water Wall and chemical clean	2006
• Chemical clean of Unit 1	2007
• Replace Boiler No. 2 Superheater	2007
• Install Cooper Ion Injection System	2007
• Replace Boiler No. 1 Superheater	2008
• Replace Unit 2 Boiler Stop Valve	2008
• Boilers Internal Cleaning, Inspection and Minor Repairs	annually

- Turbine/Generator Valves Disassembly, Inspection and Repair (each Generation Unit) every 3 yrs
- Major Turbine/Generator Disassembly, Overhaul and Repair (each Generation Unit) every 9 yrs

2.0 PROJECT DECRIPTION AND SCOPE

2.1 Study Basis [R-4]

The basis for the study is as follows:

- 2012 to 2017, Units 1 to 3
  1. Annual Capacity Factor (ACF)/pattern:
     - ACF between 30% and 75% until 2017
     - Total starts expected to increase
  2. Reliability: high, similar to current
  3. Condition Assessment and Life Extension Schedule:
     - Phase 1 -2010
     - Phase 2 – 2012 to 2013
     - Implementation – 2013 and beyond

- 2017-2020 Generation Standby, Units 1 to 3
  1. Capacity required: ACF/Operating pattern: up to 10%
  2. Hot/cold standby – time for return to service, and
  3. Reliability/availability of generation

- 2020, Decommissioning of Units 1 and 2

- 2020 to 2041 Synchronous Condensing, Unit 3
  1. Capability (generator, transformers) – similar to current Unit 3 role

2.2 Focus

The objective of Phase 2 of the Holyrood Thermal Generating Station Condition Assessment and Life Extension Study is to assess potential degradation problems, and validate or revise remaining life predictions for the major components and systems selected by Nalcor based on the Level 1 Condition Assessment completed in 2010 [R-1]. The project was also to provide the technical basis for a maintenance and repair program, including potential Level III activities that will assure continued operation with the desired level of reliability, over the target lifetime.

The inspection scope of work for the project was defined in the contract agreement 2012-51007 [R-3], and focused on NDE inspections of the boilers on Units 2 and 3, and high-energy piping on all three units. Steam piping hanger inspections were to be conducted in both the cold and hot condition on all three units. The scope identified in the contract documents is provided in Appendix A, marked to indicate the work completed in 2012, and in April 2013. The scope was modified again in the field as described in the Sections 3.2 and 4.1.

3.0 METHODOLOGY

3.1 Background Information and Studies

The Holyrood Condition Assessment and Life Extension Study Phase 2 is to be conducted on the boiler, and high-energy piping using the Electric Power Research Institute (EPRI) Condition Assessment methodology identified as Level II as outlined in Table 1, and described in more detail in the Phase 1 report [R-1]. Where the Level I assessment is based on design data and operating records, Level II augments the information with inspection data to refine life estimates and confirm expected degradation concerns. The primary method of obtaining the additional information is through Non-Destructive Examination (NDE).

In general, remaining life assessments for one unit can be translated to others where configuration, operating conditions, and operating and maintenance history are similar. Steam piping results are not as transferable due to greater sensitivity to operating events. In the present case, remaining life results from Unit 2 boiler can be applied to Unit 1 with verification on major damage mechanisms on the second unit.

For the present project, the Level I boiler and pressure piping assessment completed by AMEC NSS in 2010 [R-2], was used as the basis for the Level II assessment.

Table 1: EPRI Condition Assessment Level of Detail

Feature	Level I	Level II	Level III
Failure History	Plant records	Plant records	Plant records
Dimensions	Design or nominal	Measured or nominal	Measured
Condition	Records or nominal	Inspection	Detailed inspection
Temperature and pressure	Design or operational	Operational or measured	Measured
Stresses	Design or operational	Simple calculation	Refined analysis
Material properties	Minimum	Minimum	Actual material
Material samples required	No	No	Yes

3.2 Field Investigation

A project kick-off meeting was held on July 30, 2012 to refine the Unit 2 inspection scope and establish contracts with subcontractors. Scope refinement was based on preliminary field inspections, recent inspection history, and accounted for the annual boiler inspection scope to remove any overlap.

Major adjustments to the 2012 effort are identified below:

- The Unit 3 boiler was removed due to unit return to service commitments, and the logistics with inspecting two boilers concurrently.
- Piping inspection scope was extended to the turbine; previously considered part of the turbine scope.
- Economizer inlet header internal inspection was removed after accepting the results from the inspection conducted in 2010.
- Unit 1 and 3 piping inspections were removed from scope due to potential delays in returning the units to service, and resulting impacts on unit unavailability.
- Unit 2 boiler penthouse and locations involving removal of boiler cladding were excluded due to asbestos issues and the time required to prepare the locations for inspection. This resulted in the riser tube, SH4, superheat link piping and the economiser stub tubes being removed from scope.
- The steam drum internal inspection was reduced from full drum, to half (east side) due to time restrictions.

The 2013 scope focussed on Unit 1 and included boiler, steam piping and piping supports. Specific inspections were:

- Boiler steam drum investigation of damage at the downcomer, and other locations in the steam drum not inspected in Unit 2
- Boiler Secondary Superheat outlet header (SH6) nozzles for damage similar to that found on Unit 2, and for evidence of a seam weld
- Boiler Reheat outlet header (RH2), nozzle and girth weld replicas, and etching for evidence of a seam weld. Minimal work was done on the RH2 to minimize the impact on the project budget.
- Steam piping inspections were conducted to assess remaining life, and possible damage from the January turbine excursion.
- Steam piping support inspections (walkdowns) were conducted to complete the hot walkdown on Unit 3, to follow-up on abnormalities identified during the walkdowns in 2012, and on Unit 1, to identify any damage to pipe supports from the January turbine excursion.

3.2.1 Project Preparation

Project preparations consisted of the development of inspection specifications, review of procedures and methods to be applied, and establishment of processes and methods of communication, data transfer and quality assurance, and a safety plan.

For Unit 2, AMEC NSS qualified and provided technical direction to the NDE contractor (Acuren). On Unit 1, qualification of the NDE contractor was the responsibility of Nalcor. In both cases, either technical specifications or work plans were provided to Nalcor, the NDE contractor and the support services contractor (B&W) to direct the inspection method. Day to day oversight and reporting was provided by the on-site AMEC project representative. Following are the major preparatory activities:

a. Boiler and Steam Piping NDE Scope Specifications
Specifications and acceptance criteria were developed from AMEC NSS methodologies based on EPRI best practice. For high temperature creep, the practice included a combination of magnetic particle inspection to detect surface macro flaws, linear Phased Array Ultrasonic Testing (PAUT) to identify mid-wall flaws, and replication to characterize component microstructure and detect incipient creep. Focussed PAUT was used to better quantify any volumetric flaws identified through the linear phased array screening.

   For low temperature components, visual and surface NDE were applied. Volumetric methods were applied to measure wall thickness and where access was not available, e.g. inside (ID) surfaces. A separate NDE scope specification document was prepared in 2012. In 2013, the NDE specifications were part of the work plan [R-21].

b. FAC NDE Scope Specification 2012
FAC inspections and assessment method were based on EPRI fossil plant FAC management guidelines. The scope specification describes locations, NDE methods, and data requirements and formats [R-7].

c. Hanger Inspection Specification
Inspection procedures were based on EPRI fossil plant high-energy piping management guidelines, and American Society of Mechanical Engineers (ASME) Power Piping Code, B31.1 methods. Data collection sheets were developed based on Holyrood piping arrangements. The same specification was used in 2012 and 2013 [R-8].

d. Remaining Life Assessment
Remaining life and re-inspection interval assessment methods applied were based on the EPRI Boiler Condition Assessment Guide, ASME Fitness-For-Service (FFS) guidelines, and National Board Inspection Code (NBIC). Methods are outlined in the 2012 work plan [R-5], and reissued for use in 2013 [R-21].

   Preparatory work consisted of generating worksheets to update remaining life assessments from the Level I assessment using new data.

e. Review NDE procedures
Under the contract structure in 2012, the proposed NDE procedures were submitted by the NDE contractor for approval by AMEC NSS. Approval is based on

suitability of the procedure to identify potential defects as required by the inspection specifications. Procedures were also to be compliant with appropriate ASME codes, and to Canadian General Standards Board (CGSB) requirements, or suitable international standards in cases not addressed by CGSB, or ASME.

For the 2013 Unit 1 inspection campaign, the NDE contract and qualification was the responsibility of Nalcor. ANEC NSS reviewed the replica and Phased Array Ultrasonic Testing (PAUT) procedures to assess suitability for purpose, and limitations, as described in Appendix B of the work plan [R-21]. Capability of the PAUT procedure was accepted by Nalcor [R-23].

3.2.2 Site Mobilization and Execution

Site mobilisation was the period where the inspection and support personnel and equipment were moved to site, and work plans and locations, safety plans, and training were finalised. In 2012, AMEC NSS engineers were at site for the initial period to review work practices with other project groups, establish the safety program, and identify specific locations for inspections. A second visit was made at the beginning of the NDE campaign. A similar approach was taken in 2013 with the exceptions that Nalcor was responsible for health and safety, and no additional training was required. Further, an AMEC NSS engineer remained at site for two weeks to complete support coordination of the PAUT and replica inspections.

Cold walkdown of the hangers on the identified systems were conducted in late September. Hot walkdowns were completed on Units 1 and 2 in November.

The hot walkdown on Unit 3 was conducted in April 2013, along with follow-up on abnormalities identified in the 2012 effort, and specific inspections on Unit 1 supports to address concerns from the turbine trip event.

3.2.3 Screening

In 2012, all NDE results, raw data and reports were loaded to a web-based Data Management System (DMS) to facilitate access for project staff. These arrangements were established by the NDE contractor.

AMEC NSS reviewed the NDE results when obtained to assess acceptability, and the need for immediate follow-up, e.g. repair. The actual fitness for service assessment and repair was the responsibility of the boiler maintenance contractor, B&W.

Upon completion of the inspection and related activities, a preliminary report was generated summarizing the results of all inspections [R-10].

In 2013, preliminary results were provided to AMEC NSS as they were generated. Final reports were supplied by e-mail.

3.2.4 Data Analysis

Analysis consisted of the generation of the expected remaining life and recommendations for life management activities. Methods applied are described in Section 3.2.1 (d), in the AMEC NSS project work plan [R-5], and revised work plan [R-

21]. The Phased Array (PAUT) methods were accepted by Nalcor as documented in Reference 23.

4.0 INSPECTION RESULTS

A summary of NDE inspections completed and results for both the Unit 2 work in 2012 and the Unit 1 work in 2013 is provided in Table 2. Further details of the Unit 2 NDE results are provided in the Summary NDE report [R-10]. The Unit 2 FAC inspection results are reported in Appendix D. The high-energy steam piping hanger inspections are summarised in Appendix E for both Units 1 and 2. The 2012 NDE reports, supporting material, and scope documents are provided in a reference binder [R-9]. Results for the 2013 effort are provided in a second reference binder [R-22]. The assessment of the inspection results is in Section 5.

4.1 NDE Results

4.1.1 Unit 2

NDE on the Unit 2 boiler and piping was conducted over the period of October 1 to October 14, 2012. Repairs were completed on October 16, 2012. The scope of work completed in this period included scaffolding, insulation, NDE, restoration of insulation and removal of scaffolding.

Due to the time restrictions, NDE was completed on only a limited number of sites. The effort was also restricted by the need for repairs. In the case of the high temperature headers, the Secondary Superheater (SH6) west outlet nozzle was added to scope after finding damage in the east outlet nozzle weld. Additional replication was added to characterize the microstructure of the grind out area.

The waterwall inspection locations were modified slightly to facilitate access. The lower side wall was moved from elevation 24’ to elevation 33’, and the rear wall/side location wall at elevation 64’ was moved from corner 3 (west side) to corner 4 (east side). None of the changes affected the objectives of the inspection, as conditions promoting damage initiation and accumulation exist at the new locations.

Further, the project was requested to complete inspections of the Secondary Superheat outlet header stub tubes after fatigue cracking was detected in several tubes, and steam drum downcomer inspections were extended to all four downcomers from the initial plan of inspecting only two.

On the Secondary Superheat Outlet Header (SH6), the Reheat Outlet header (RH2) and Reheat Inlet header (RH1), most of the planned NDE was completed. There was not sufficient time to complete the replication on the RH2. Partial grinding and etching of the SH6 and RH2 was conducted to identify the seam welds. No seam weld microstructure was found. Further effort to locate or inspect the header seam welds was suspended.

FAC inspections were completed at four locations between the low pressure feedwater piping, the high pressure feedwater piping and the superheat attemperator water supply piping. The results are reported in Appendix D. Material testing to determine the presence of chromium was also attempted. The results were inconsistent with possible material specifications and were therefore considered not reliable, and are not used in this assessment. Chromium data was beyond acceptable ranges and cobalt indications are inconsistent with anticipated results. These outcomes question the validity of the measurements. This is considered a procedure compliance issue and not an issue with the method or equipment.

4.1.2 Unit 1

The 2013 NDE was executed on Unit 1 in April. Damage was found in the east nozzle of the SH6 and at the inlet weld to the Boiler Stop Valve. In both cases, the damage was removed by grinding. A weld repair was required at the east SH6 nozzle. Inspection and repair of the SH6 stub tube welds was conducted under the Boiler Maintenance contract and is not discussed in this report.

A macro etch process was used to inspect the Unit 1 RH2 for a seam weld. The inspection was limited to approximately 270 degrees of the circumference due to inadequate space. No seam weld was identified. There were no FAC inspections on Unit 1 due to cost constraints.

Table 2 Unit 1 and Unit 2 NDE Results

Unit	Area	Location	Potential Damage Mechanism	Comments
Boiler NDE				
U2	Waterwall tubes Cold side attachments	Windbox connection at top of burner Corner 2 (L 4-5)	Corrosion fatigue (ID cracking at attachment)	No relevant indications
		Buckstay corner Elev 59'-10' Corner 1 (L4-5)	Corrosion fatigue	No relevant indications
		Buckstay corner at Rear wall, elev 64'-10", Cor 3 (L5)	Corrosion fatigue	No relevant indications
		Side wall/ slope at buckstay, elev 33'-1" west wall (L 2)	Corrosion fatigue	No relevant indications
U1&2	Boiler Drum	General visual of drum internal for major damage	Mechanical fitness	No major damage was detected in the general visual and MT inspections
		Downcomer penetrations – nozzle weld to drum (ID)	Thermal Fatigue	Field of cracks (both units) Weld repaired
U1	Boiler Drum	Riser and Saturated steam nozzles sample (10%)	Thermal fatigue	No Sat Steam nozzles due to access issues 27 bore holes inspected (4%, Unit 1) Minor indications at edge of one inspected bore hole - benign
		Seam Weld	Thermal fatigue	No relevant indications
U1	Riser Tubes	ID of tubing from stm drum to headers	Corrosion Fatigue Pitting	Axial scoring noted in most – not active Isolated pitting in most, aligned puts in 18E – not active
U2	Downcomer (Level 1)	Downcomer to H1 header nozzle welds Lower Vest)	Thermal Fatigue	No relevant indications
U1&2	Secondary Superheat Outlet Header (SH6) (Level 8)	Header thickness	Creep	Input to remaining life assessment
		Header outlet nozzle welds	Creep	Cracking found in U2 East nozzle at 12 and 6 o'clock. Similar damage at West nozzle. Most

Unit	Area	Location	Potential Damage Mechanism	Comments
			Weld Defect	damage removed by light grinding. Weld repair required at the 6 o'clock position No creep voids were reported on U2. U1 creep damage reported at toe of weld, East nozzle. Damaged was removed and weld repaired. MPI only on U1 West nozzle. No damage found.
		Stub Tubes	Fatigue Creep Fatigue	Cracking found in 58 of 124 stub tubes in the tube side toe of weld on U2. Similar on U1.
U2	Secondary Superheat Outlet Header (SH6) (Level 8)	Drain (also seem to act as a vent. Inspect at weld to hdr in hdr vestibule)	Thermal Fatigue	Header ID visually inspected at the drain penetration during header internal inspection. No evidence of cracking
		Header internal – boroscope	Creep/Creep Fatigue Thermal Fatigue	No visual evidence of creep cracking (ligament or other cracking)
		Header seam welds	Creep/Creep Fatigue	No seam weld found in limited inspection on U2
U2	CRH Header (Level 10)	CRH Header Internals - boroscope	Thermal Fatigue	No visual evidence of cracking
U2	HRH Header (Level 8)	HRH Header Internal	Creep/Creep Fatigue, Thermal Fatigue	No visual evidence of creep cracking (ligament or other cracking)
		Header supports (50%)	Fatigue Creep Fatigue	MT was completed on two of four support welds. No relevant indications were found
		Header Girth Welds	Creep/Creep Fatigue	MT and PAUT was completed on the east header outlet nozzle, east and west butt welds. No relevant indications were found. No Replication was performed
U1	HRH Header (Level 8)	Header Girth Welds	Creep/Creep Fatigue	Replicas were taken at the west Tee outlet nozzle and west header welds. No relevant indications were found.

Unit	Area	Location	Potential Damage Mechanism	Comments
		Stub Tubes	Fatigue	Sample inspected. No relevant indications identified
U1&2	HRH Header (Level 8)	Header Seam Welds (50%)	Creep/Creep Fatigue	No seam weld found Weld potentially fully normalised in manufacture. Inspection was incomplete
Steam Piping NDE (2012)				
U2	Main Steam	• East Boiler Link (L8) • Thermowell • Gamma plug	Creep/Creep Fatigue	MT, PAUT and Replication completed No relevant indications found No evidence of creep voids
U2	Main Steam	• West Gov Valve Terminal (Flange weld) (L3)	Creep/Creep Fatigue	MT, PAUT and Replication completed Possible isolated voids reported in replicas No relevant indications found by MT and PAUT
U1	Main Steam	• West Boiler Link Weld • Thermowell • Gamma plug	Creep/Creep Fatigue	MT, PAUT and Replication completed No relevant indications found No evidence of creep voids
U1	Main Steam	• Shop Weld above BSV (elev 54") (Pic 10) • Instrument penetrations	Creep/Creep Fatigue	Limited access to girth weld due to hanger collar. MPI only. No evidence of cracking
U1	Main Steam	• Boiler Stop Valve, upstream weld (Pic 9) • Gamma plug • Drain	Creep/Creep Fatigue Fatigue/Thermal Fatigue at drain	Creep damage in outer layer of weld. Material found to be lower alloy content (portable alloy analyser). Outer weld layer removed by grinding. No repair required
U1	Main Steam	• East Main Stop Valve Outlet Nozzle Weld	Creep/Creep Fatigue Fatigue	MT, PAUT and Replication completed No relevant indications found No evidence of creep voids
U1	Main Steam	• East Gov Valve Terminal (pipe to elbow)	Creep/Creep Fatigue Fatigue	MT, PAUT and Replication completed No relevant indications found No evidence of creep voids

Unit	Area	Location	Potential Damage Mechanism	Comments
U1	Main Steam	• West Gov Valve Terminal (Flange weld)	Creep/Creep Fatigue Fatigue	MPI only No evidence of relevant OD indications
U2	Hot Reheat	• East Boiler Link (L8) • Thermowell • Gamma plug	Creep/Creep Fatigue	MT, PAUT and Replication completed No relevant indications found No evidence of creep voids
U2	Hot Reheat	• Upper Y east weld and crotch (L7) • Hanger lug – east side • Gamma plug	Creep/Creep Fatigue	MT, PAUT and Replication completed No relevant indications found No evidence of creep voids
U1	Hot Reheat	• West Boiler Link (Pic 5) • Thermo Well • Gamma plug	Creep/Creep Fatigue	MT, PAUT and Replication completed No relevant indications found No evidence of creep voids
U1	Hot Reheat	• Lower Y inlet weld (Pic 11) • Hanger lugs • Gamma plug	Creep/Creep Fatigue	Two welds for inlet spool piece inspected by replica, PAUT and MPI. No relevant indications found No evidence of creep
U1	Hot Reheat	• East CSV Inlet (Pic 13) • Drain	Creep/Creep Fatigue	MT, PAUT and Replication completed No relevant indications found No evidence of creep voids
U1	Hot Reheat	• East Turb Terminal (Flange weld)	Creep/Creep Fatigue Fatigue	MT, PAUT and Replication completed No relevant indications found No evidence of creep voids
U1	Hot Reheat	• West CSV outlet	Creep/Creep Fatigue Fatigue	MT, PAUT and Replication completed No relevant indications found No evidence of creep voids
U2	Cold Reheat	• East Boiler link (L9)	Fatigue	MT and PAUT completed No relevant indications found
U1	Cold Reheat	• West Boiler Link	Fatigue	MT and PAUT completed No relevant indications found
U1	Cold Reheat	• Lower Y Inlet • Hanger Lug Above Y	Fatigue	MT and PAUT completed No relevant indications found

Unit	Area	Location	Potential Damage Mechanism	Comments
U1	Cold Reheat	• East Turbine Terminal	Fatigue	MT and PAUT completed No relevant indications found
Unit 2 Feedwater Piping FAC Survey				
	Area	**Location**	**Damage Mechanism**	**Comments**
2	HP Feedwater Piping	Htr 4 Disch double elbow (L5)	FAC	Fit for Service Evidence of FAC
6	LP Feedwater	Elbow and T out of #2 heater (LP Htr deck)	FAC	Fit for Service No evidence of FAC
5	SH Attemperator Supply Piping	East SH Attemp Supply Flow Element (FE 5568)+ piping (L11)	FAC	Fit for Service No evidence of FAC
	SH Attemperator Supply Piping	West SH Attemp V/v Stn Flow Element 1TV 619B &D (L11)	FAC	Fit for Service Low wall thickness down stream of TCV, possibly due to erosion. Reinspect at 3 years

4.2 Damage Findings and Repair

4.2.1 Steam Drum Downcomer Nozzles

Thermal fatigue cracking was detected in the steam drum at all four downcomers in both Units 1 and 2. A sample of typical damage is provided in Figure 1.

The cracking was oriented in the east west direction (axial to the drum) the maximum depth on Unit 2 was reported as 4.3mm (0.170”). The maximum depth on Unit 1 was 5.3mm (0.21”).

The damage was removed by grinding. On Unit 2 the original profile was restored by B&W with a weld repair. For Unit 1, the damage was dispositioned by B&W as acceptable. The flaws were blended out.

Figure 1 Steam Drum Cracking at the Downcomer Nozzles – Typical Damage

4.2.2 Steam Drum Riser Tube Nozzles

A sample of 27 riser tube nozzles were inspected on Unit 1 in 2013. The riser tube penetrations inside the steam drum were inspected for thermal fatigue cracking. There were no relevant indications found.

The same risers were inspected visually with a video probe from inside the steam drum to the upper waterwall header. Scoring was noted on the axial wall, and pitting. Most of the pitting was random but in at least one case, multiple pits aligned in the axial direction were noted. A sample is provided in Figure 2. The damage is not considered an immediate integrity concern but further investigation of the severity and numbers of risers affected is required.

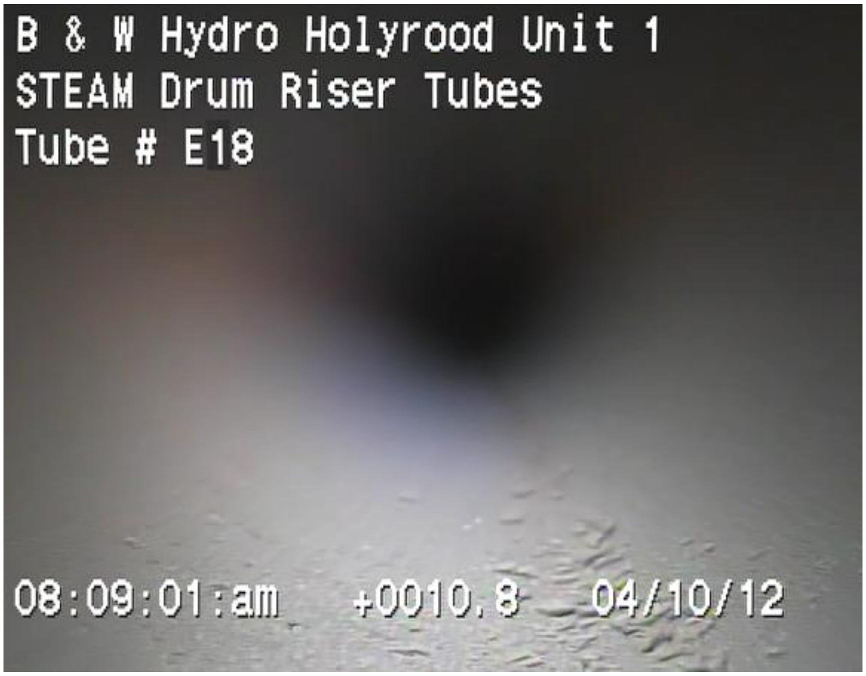


Figure 2 Aligned Pits in the Bottom of a Riser Tube (bottom of picture)

Note: date of inspection is incorrect

4.2.3 Secondary Superheat Outlet Header (SH6) Nozzles

The secondary superheat outlet header has two outlet nozzles of welded branch design. On Unit 2, cracking was detected in both the east and west outlet nozzle welds, at the 12 o'clock and 6 o'clock locations. The configuration and cracking at the east nozzle 12 o'clock location is shown in Figure 3. Details of the cracking are shown in Figure 4.

The cracking was removed by grinding. Magnetic particle testing (MT) was used to determine there were no remaining relevant indications. In three of four locations, the damage was removed by light grinding. In the fourth location, 6 o'clock on the east nozzle the maximum grind out was about 7mm. This depth was assessed as unacceptable by B&W and a weld repair was made.

Replication after grinding identified remaining micro cracks. This condition was found at the east nozzle, 6 o'clock position. It is anticipated the micro-cracks would be consumed in the weld repair. There were similar indications identified in the 6 o'clock grind out area on the west nozzle. As none of the indications was apparent by MT, the component was determined fit for service.

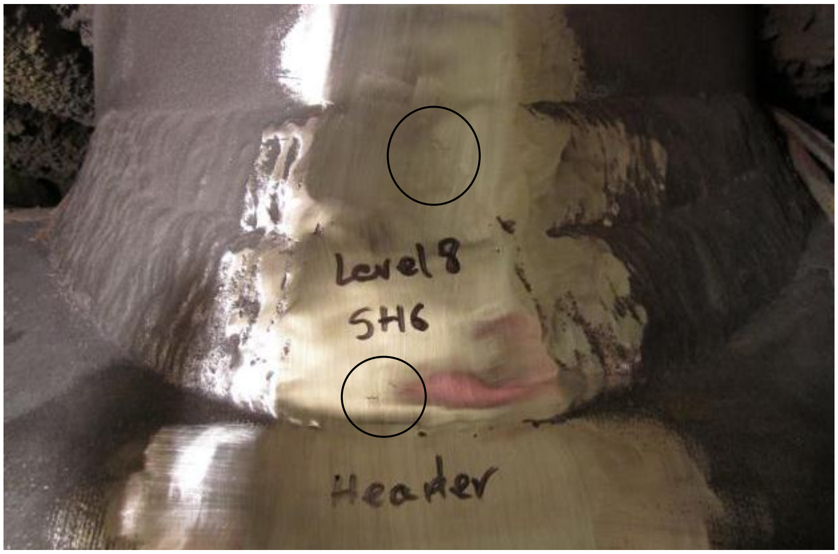


Figure 3 Unit 2 SH6 Outlet Nozzle Configuration and East Nozzle Crack Locations

Figure 4 Unit 2 SH6 Outlet Nozzle Cracking, Lower 12 o'clock Position on East Nozzle

The Unit 1 SH6 nozzle inspections consisted of MPI on both welds and follow-up on any findings. Multiple cracks were identified in the weld on the east nozzle, Figure 5. Replication of the cracks concluded that the damage was creep extending into the heat affect zone of the header. The damage was removed by grinding and weld repaired. The depth was approximately 9 mm (0.35"). There was no damage detected at the east nozzle.

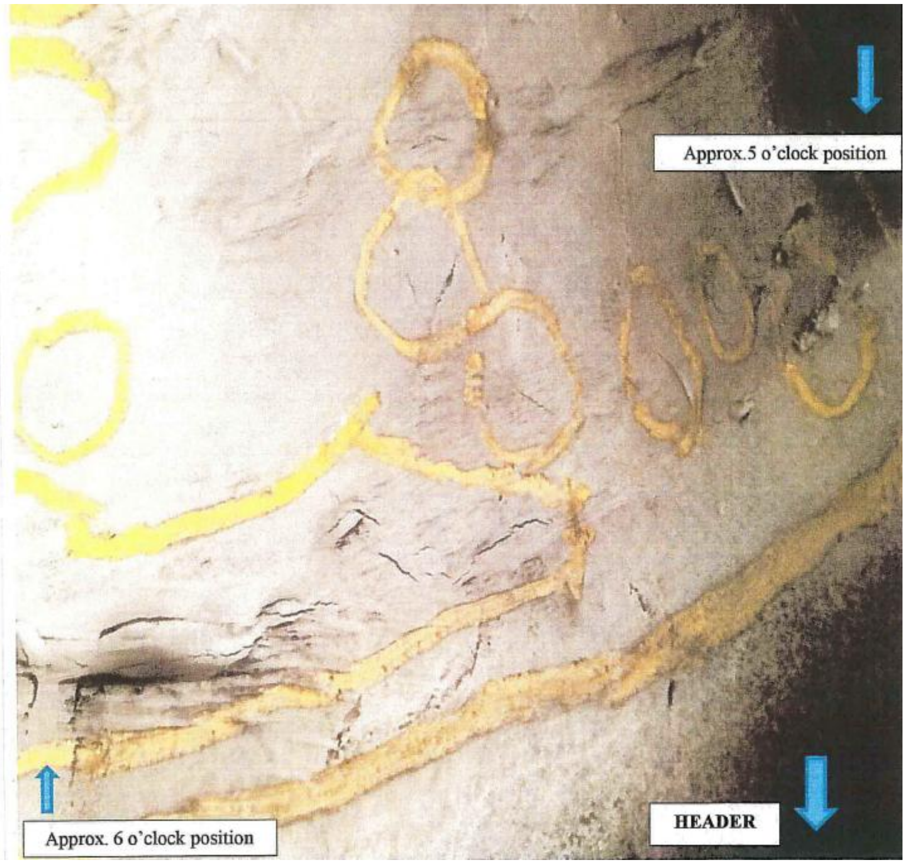


Figure 5 Unit 1 SH6 East Outlet Nozzle weld cracking

4.2.4 Secondary Superheat Outlet Header Stub Tube Cracking

Cracking in the tube side of the SH6 stub tube fillet weld was observed on Unit 2 by the NDE technicians while preparing for work at another site. In subsequent inspections, cracks were found in 58 of 124 stub tubes, typically towards the outer end of the header and in the lower two tubes in the platen. A sample of typical damage is identified in Figure 6.

The damage was removed by grinding and weld repairs were made by B&W. Similar damage was identified on Unit 1 and was weld repaired.

Figure 6 SH6 Stub Tube Weld Toe Cracking – Typical

4.2.5 Steam Piping Inspections

Findings on the steam piping were isolated creep voids in the West Main Steam line weld to the turbine flange on Unit 2, and macro-cracking in a layer of low alloy weld material on the Unit 1 Boiler Stop Valve (BSV) inlet weld.

At the BSV, preliminary results from a portable material analyser suggested the damage was in a layer of weld material with a lower alloy content than required in this application. Replication indicated the damage was creep and confined to the layer of weld material. The creep damage was removed by grinding out the lower grade material. The remaining wall thickness was assessed by B&W as adequate such that a weld repair was not required. Details on the finding are described in the replication report, included in the Unit 1 inspection reference binder [R-22].

No other damage was found on the inside diameter (ID), mid-wall or the outside diameter (OD) of the pipe welds inspected by NDE on either Unit 2 or Unit 1. Similarly, there was no damage identified at the instrument penetrations, hanger lugs or other attachment to the steam piping.

4.3 Creep Damage

Creep damage is naturally occurring in metals at high temperature and under stress. The temperature requirements for creep for carbon and alloy steel are dependent on alloy content. For carbon steel, the creep limit is about 375 ^{o}C [R-28]. Advance creep damage will lead to crack initiation and growth, and eventually, failure.

Inspection for advanced creep damage was investigated by in-situ replica metallography. The technique is used to visually detect creep void formation in the material microstructure. Replicas were taken across selected welds to capture samples of parent material, heat affected zone (HAZ), and weld metal microstructures. Locations and results are identified in Table 2, and in the replica reports contained in the project reference binders for Unit 2 [R-9], and for Unit 1 [R-22].

Creep damage in the form of isolated voids was reported in the Unit 2 west main steam to turbine flange weld. In addition, the replica evidence from the SH6 outlet nozzles identified artefacts similar to creep. A sample of the SH6 nozzle indications is provided in Figure 7a. There was no evidence of creep voids after the crack in Figure 7b was removed.

Damage in the Unit 2 main steam lines at the turbine flange was classified as Type III, isolated voids. A sample is provided in Figure 7c. The indications in the SH6 nozzle welds could be classified the same way. From industry guidelines, repair is not required for Type III, isolated void creep damage. The disposition of creep damage and follow-up is discussed further in Section 5.

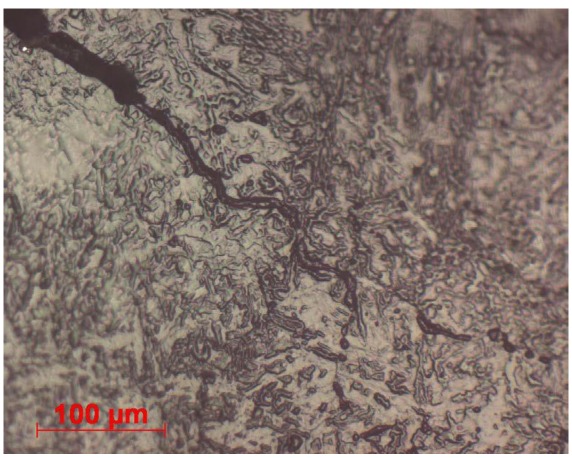


Figure 7a Crack tip microstructure
Unit 2 SH6 East Nozzle, 12 o'clock

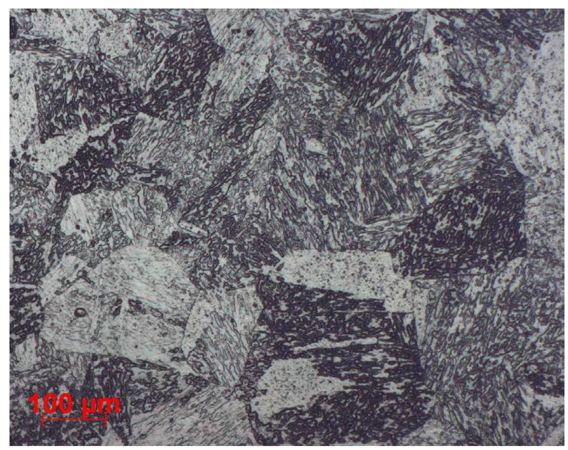


Figure 7b Microstructure after crack removal, with no evidence of creep

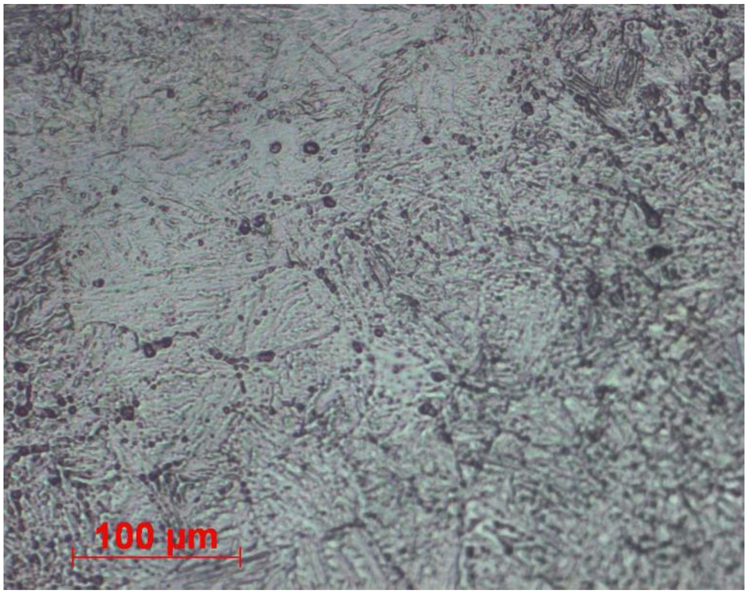


Figure 7c Possible isolated creep voids in the Unit 2 West main steam pipe turbine flange weld course grained HAZ (Type III).

The cracking on Unit 1 was in the weld, similar to that found on Unit 2 with the exception that up excavation, the cracking on Unit 1 extended into the Heat Affect Zone (HAZ) of the header. Both units exhibited oxide filled intergranular cracking on the outside diameter (OD), similar to that in Figure 7a. The fact the cracking was removed by grinding suggests the damage was surface initiated. The damage can be classified as Type III creep damage. The random nature of the cracking and the apparent link to weld termination points, particularly on Unit 2 suggest the damage may also be the result of original weld defects.

4.4 Wall Thickness Measurements

Wall thickness measurements were taken on the boiler components and steam piping that operates at temperatures supporting creep (greater than 375 ^{o}C). The thicknesses are used to support creep rupture life calculations that define end of life due to creep. Results from Unit 2 are used in the creep life calculations presented in Appendix C.

The Unit 1 results are summarised in Table 3. Not all data was used due to inconsistencies in reporting. Base on the reliable data, all Unit 1 measurements were above the minimum required thicknesses used in the creep life calculations. Follow-up is required on the Hot reheat system.

Table 3 Unit 1 Wall Thickness Measurement for Creep Life Assessment

	Location	Minimum Wall Required (for Calculations)	Measured Wall (minimum)
SH6	At nozzle	71.6 mm (2.812")	75.3 mm (2.965")
RH2	Along length	31.75 mm (1.25")	35.6 mm (1.402")
Main Steam	Boiler Link	32.5 mm (1.279")	36.1 mm (1.422")
	Elbow Weld above BSV	40.5mm (1.593")	44.3 mm (1.746")
	MSV Outlet	32.5 mm (1.279")	36.1mm (1.422")
	East Turbine Inlet	32.5 mm (1.279")	34.5 mm (1.36")
Hot Reheat	Boiler Link	16.1 mm (0.633")	18.4mm (0.724")

4.5 Hanger Inspection Results

Hangers on the main steam, hot reheat and cold reheat piping were inspected in the hot and cold condition on all three units. The purpose of the inspection was to determine if the hanger configuration was consistent with design, to assess whether the pipe hangers are in acceptable operating condition, and to identify evidence of load redistribution, mechanical damage, sagging, or distortion. On Unit 1, an added objective of the hanger inspection was to determine if there was any damage resulting from the turbine trip event in January 2013.

The results indicated the hangers were in generally acceptable condition. No immediate corrective action or repair was required. Repair to the concrete mount for the HR15 and 17 stanchions on Unit 1 is recommended at the next opportunity, within a year. Details of the inspection results are provided in Appendix E, and in the project reference binders [R-9, R-22].

The main observations are identified below. The assessment is contained in Section 5.

- The main steam piping hangers on Units 1 and 2 did not conform to the original design in that the constant load hangers at the MS8 position had been changed to variable load hangers.
- There was no evidence of significant load redistribution, piping distortion (skewing), or sagging. The majority of the hangers operated within acceptable loading ranges in the hot and cold condition. Several hangers were identified in the topped or bottomed-out position, or did not change position between hot and cold load.
- There were a number of hangers with minor mechanical issues including missing lock nuts, evidence of corrosion, and several trapeze arrangements with distorted load distribution.
- In general, there was no evidence of significant operating upsets. Minor damage to insulation was noted in several locations. There was damage noted at the HR15

and HR17 base mounts at in the concrete. This was likely due in part to the Unit 1 turbine trip in January 2013. There was also long term general corrosion of the stanchions.

5.0 CONDITION AND REMAINING LIFE ASSESSMENT

The intent of the Phase 2 work program is to generate sufficient information to assess the risks to reliability and safety of in-service damage mechanisms not previously identified through operating history and the annual maintenance programs. The assessment is based on inspections conducted on the Unit 1 and 2 boiler and high energy piping, and high energy steam piping supports on all three units complete.

The following sections review the inspection results in terms of the impact on remaining life relative to the results from the Level I assessment (Phase 1 of the project), [R-1, R-2]. Recommendations are generated where possible. The inspection locations and results are summarised in Table 2 and in the 2012 NDE summary [R-10]. NDE reports are provided in a reference binders [R-9, R-22]. For the purpose of the remaining life assessments, it is assumed the unit has been and will continue to be operated within limits (temperatures and pressures) specified in operating procedures.

Risks are assessed in a separate subsection using the models attached in Appendix B.

5.1 Boiler Tubing

5.1.1 History

The Holyrood units have had various problems in the boiler tubing due in part to the fuel quality, seasonal operation, poor process water quality control, and boiler design issues. The following mechanisms are applicable:

Fuel quality:

- Fireside corrosion
- Slagging – mechanical damage to tubing in removing slag

Process Water Quality:

- Hydrogen damage and Inside Diameter (ID) corrosion of waterwall tubing
- Stress corrosion cracking of superheat stainless steel tubes at welds

Design Issues

- Corrosion fatigue in the economiser inlet header stub tubes
- Corrosion fatigue in waterwall tubing
- Premature failure of Dissimilar Metal Welds (low alloy steel to stainless steel) in superheat and reheat tubing.

Seasonal Operation:

- ID corrosion, pitting, and general corrosion

Holyrood has taken a number of steps to address the major historical issues including those listed below. In most cases the corrective action has involved replacing tubing.

- Changed fuel to high quality to reduce fireside corrosion and slagging.
- Reviewed and upgraded cycle water chemistry to avoid conditions that could result in hydrogen damage or accelerated ID corrosion. Units 1 and 2 were also chemically cleaned to remove ID deposits that are an integral part of the hydrogen or caustic ID corrosion processes.
- Reviewed and upgraded lay-up procedures.
- Implemented an aggressive annual boiler inspection program to monitor damage accumulation. Local modification of attachments was completed to reduce the potential for corrosion fatigue.
- Upgraded stainless steel superheat tube materials at welds to reduce sensitivity to stress corrosion cracking, and avoid potential premature dissimilar metal weld failures.
- Limited investigation to assess creep damage. Tube replacements and material upgrades will also contribute to minimising the impact of creep damage.

5.1.2 Assessment

Due to the extensive annual inspection program and previous work, the inspection program for boiler tubing was limited to the issues identified below. ID corrosion is in waterwall and stress corrosion cracking in stainless steel steam tubes are not considered a major life issue due to the efforts in the last 10 years to address the damage and root cause, poor cycle water chemistry control. Recent reports of ID corrosion causing thinning of reheat tubing suggests that lay-up practices may still be a concern.

Major issues are:

- Corrosion fatigue in waterwalls for all units.
- Corrosion fatigue and FAC in economiser inlet header stub tubes for Units 1 and 2.
- Accelerated degradation of reheater tube dissimilar metal welds (original welds) in Units 1 and 2.
- ID corrosion (oxygen pitting) in horizontal sections of tubing.

Of the four issues assessed, the waterwall corrosion fatigue inspections were completed on Unit 2. There were no tube inspections on Unit 1, but ID pitting in tubing can be inferred from the riser tube inspection results from Unit 1. These results are discussed in Section 5.3.

<u>Corrosion Fatigue</u>

Four waterwall locations were selected based on the worst case combination of pressure, thermal, system and geometric stresses. Guidance is provided in EPRI report TR-100455 V4 [R-11]. The inspection was done using digital Radiographic Testing (RT). The locations are identified in Table 2.

Although digital radiography will not detect incipient cracking, it will be possible to detect advance level damage in multiple tubes that could present a reliability problem within the period to the desired end of life. The results indicate that there is no evidence of cracking.

Based on a lack of failure history and the lack of evidence of damage at locations in Unit 2 considered to be of high susceptibility, it is concluded that Units 1 and 2 have a low likelihood of reliability or safety concerns due to waterwall corrosion fatigue.

Unit 3 has a history of corrosion fatigue waterwall tube failures. Inspections should be part of the scope of work for Unit 3.

Circumferential cracking at the economiser inlet header stub tubes can result from corrosion fatigue. The mechanism can be accelerated by FAC. Inspections in these areas have been deferred due to schedule limitations.

Oxygen Pitting

Random to severe, aligned pitting was identified in the riser tube inspections on Unit 1. Further, it was reported that wall thinning from ID corrosion had been detected in the reheat tubing. These results suggest the boiler was partially drained and the steam drum vents opened during lay-up exposing the tuning to a wet oxygenated environment. These conditions may also cause pitting or general corrosion in horizontal sections of steam tubing as well if water (condensate) is not properly drained. Such conditions are indicated by sagging of horizontal tubes between supports.

Waterwall tubing and feeder tubing at the bottom of the boiler is less likely to be affected as these areas are filled with water during lay-up periods.

Unit 3 may also experience the same issue and inspections are recommended.

Dissimilar Metal Welds

Dissimilar metal welds (DMWs) between ferritic low alloy steel to austenitic stainless steel in high temperature service can fail prematurely, particularly where there is a bending stress. Sampling and destructive examination of original welds in the Units 1 and 2 reheat tube sections would provide an indication of remaining life.

5.1.3 Actions

The lack of corrosion fatigue damage in susceptible locations in Unit 2 suggest further investigations can be treated as a lower priority on Units 1 and 2. Additional inspections can be conducted to improve confidence in this conclusion. A review is recommended.

Inspections for waterwall corrosion fatigue using digital RT should be added to the Unit 3 boiler life assessment scope.

Planned inspections of the economiser inlet header stub tubes need to be completed on Units 1 and 2.

Wall thinning of boiler tubing is managed through the boiler maintenance program. The pitting in the riser tubes and reports of corrosion in reheat tube suggest radiography of sample horizontal steam tubing showing evidence of sagging be considered for this program to investigate evidence of pitting or general corrosion, and to assess the severity of damage. Periodic sampling of waterwall tubing in high heat flux areas needs to be part of the routine boiler program (3 year intervals). Cycle water chemistry control performance needs to be monitored and action taken if consistent poor performance is identified.

Reheat DMW sampling is not required as tubing containing the welds is to be replaced due to ID corrosion.

There are no capital reinvestment requirements at this time.

5.2 Steam Drum

5.2.1 History

The stream drums on all three units are subject to annual inspections of the accessible penetrations on either end of the steam drums. The results suggest the steam drums experience thermal fatigue cracking, or thermally driven corrosion fatigue cracking typical of steam drums on subcritical boilers. Such damage is driven by temperature differentials created by the introduction of relatively cool feedwater during starts [R-12], and accelerated by corrosion. Cracking usually occurs at weld discontinuities due to repeat thermal transients, and can interface with weld defects to develop cracking of extended depth. Most thermal fatigue cracking in steam drums is self-arresting, i.e. cracks grow into low stress region and stop. Removal and repair can result in re-initiation. The cracking is ID surface initiated and is detected by magnetic particle testing (MT).

At Holyrood, accessible penetrations are inspected at either end of the steam drums. The majority of detected cracks in the three units were removed with light grinding. In some cases cracking has been left and is monitored for growth in length. This approach is acceptable under the Nation Board Inspection Code (NBIC) with an engineering assessment. The engineering responsibility has been accepted by the boiler maintenance contractor.

The greater damage has been reported in Units 1 and 2. Very little damage has been found in Unit 3. The riser tube, downcomer and saturated steam nozzles have not been inspected in Units 1 and 2 prior to this project. The same applies for Unit 3 with the exception of the downcomer nozzles, which are accessible from the hemi-head ends of the drum.

5.2.2 Assessment

The Unit 1 and 2 inspections consisted of MT of the hemi-head ends, downcomer penetrations, and on Unit 1 MT of a sample of riser tube penetrations and a section of a long seam weld. The planned inspections of the saturated steam nozzles were not completed due to the time required to remove, and reinstall the secondary scrubbers.

Cracking was found at the edge of the penetration for all downcomers on both units. The damage was preferentially oriented in the axial direction. All cracking was removed and weld repairs were conducted to restore the original profile on Unit 2. The Unit 1 cracking was removed and blended. Repairs were not considered necessary. There were no relevant indications identified at the riser tube penetrations or in the seam weld.

Cracking of the nature observed at the downcomers is common in steam drums and does not present an integrity, or end of life concern providing there is a management program to monitor crack extension and demonstrate fitness for service. If damage is left as a crack, there must be an engineering justification. Such a justification can be based on ASME Section I minimum wall requirements taking into account nozzle reinforcement. Alternatively, the basis for the leaving the damage would be a critical crack size assessment. In the present case, no damage has been left in the drums.

5.2.3 Actions

The findings in the Units 1 and 2 steam drum are typical of units of this design and vintage. If there is an increase in the number of unit starts in the future, cracking recurrence is likely. Periodic inspection of at least one downcomer penetration is recommended at major outages (3 years). Additional inspection and corrective action may be required if damage is found in the sample.

No further action is necessary for the riser tube penetrations. The saturated steam tube penetrations should be visually inspected on one unit but this action is considered lower priority as riser tube results indicate the root cause (thermal transients) is not significant.

Unit 3 steam drum does not have a history of significant cracking. Based on this history, the number of operating hours, the industry experience from the Phase 1 report, and the fact the major susceptible sites including the downcomers, are accessible from the ends, inspections beyond the existing annual inspections are considered a lower priority.

There are no capital reinvestment requirements at this time.

5.3 Headers and Boiler Internal Piping

5.3.1 History

The major concerns for headers and boiler internal piping are as follows:

Operating issues

- Thermal fatigue and thermally driven corrosion fatigue on the ID surface of water headers and piping, primarily at tube bore hole ligaments, pipe connections, and girth weld stress risers (weld root or counter bore notch) due to feedwater thermal cycling.
- Thermal fatigue and thermal shock on the ID surface of steam touched headers, in tube bore hole ligaments and girth weld stress risers, and at drain hole penetrations due to condensate events or attemperator operational issues.
- Creep fatigue in welds, and weld heat affected zone (HAZ) zones, and in parent material operating at temperatures in the creep range and due to thermal cycling, particularly for thick section components.

Design issues

- Creep in welds, weld heat affected zone (HAZ) zones, and in parent material, is a continuous process in components under stress operating at temperatures in the creep range. Accelerated creep can be a particular issue in seam welded Submerged Arc Weld (SAW) pipe, or in girth welds subject to bending stresses, or where there are localise high temperatures or high stresses. Damage will typically occur on the inside surface, e.g. at tube ligaments. Damage can also initiate mid-wall at susceptible microstructural artefacts or zones such as a double-J weld root, or the fine grained inter-critical zone of the weld HAZ.
- Creep, fatigue and creep fatigue damage on high temperature headers and piping at hanger/structural support weld connections.
- Thermal fatigue due to attemperator component failure.
- Outside Diameter (OD) fatigue of stub tube welds.

Seasonal Operation

- ID corrosion and pitting during lay-up, this can occur in water or steam headers and interconnect piping, including feeder/riser tubes. For steam headers the source of water is condensate.

Annual inspections at Holyrood periodically include accessing the internals of the headers and internal piping. The header access has usually been reported for the purpose of removing debris. In some circumstances, the condition of the component internals has been noted.

The economiser inlet header was inspected on Unit 3 in 2002 and was found to be without damage. Similar inspections were conducted on Units 1 and 2 in 2002. No cracking was noted. However, repeat inspections on Units 1 and 2 in 2010 identified corner cracking at the edge of a number of tube bore holes, indications between bore holes and on Unit 2, axial scoring between several tubes and in the tee crotch [R-13, R-14]. The worst damage was in the inlet tee region. Linear defects in the ligament area were estimated at 9.5mm (3/8") depth. On Unit 2, it was also determined that the inlet tee was a welded clam-shell construction. Follow-up Phased Array UT (PAUT) assessed the linear indications in the crotch region to have a depth of 1.5mm (0.063"), and other liner indications in the tube 12 region to have no recordable depth. The crotch area indications and those in the tube 12 region were reported as not crack-like. There were no similar indications in the tee crotch or tube 12 region on Unit 1. A reinspection interval of 3 years was recommended.

A partial (30%) inspection of the Unit 3 Economiser inlet header in 2010 found no evidence of ligament cracking. The 2010 inspection reports are provided in the reference binder [R-9].

The Phase 1 report identified a concern over the lack of pipe supports for the economiser link piping on to the steam drum on Unit 3. If this condition represents a support failure, the condition may lead to fatigue cracking. The condition needs to be investigated further.

Upper and lower water wall headers have been inspected at different periods primarily to remove debris. No cracking or pitting has been observed. The upper waterwall riser tubes and lower waterwall feeders are periodically inspected externally. Wall thickness has been measured and on Unit 3, shear wave UT was conducted to identify cracking. No damage had been identified.

Link piping and superheat attemperators are routinely inspected. Recent internal inspections of the attemperators found no problems. Unit 3 was inspected in 2009. Unit 1 was inspected in 2010. The construction of the link piping is not known and has not been investigated. There is a possibility that seam welded pipe could be used, particularly on Units 1 and 2. The type of construction and the possibility of subsurface creep damage needs to be investigated.

The secondary superheat inlet (SH5) and outlet (SH6) headers were visually inspected on the ID in 2007 on Unit 2 and 2008 on Unit 1. No ligament cracking was observed. However, significant cracking was observed in the Unit 1 SH6 east handhole bore. The SH6 header was inspected again on Unit 2 in 2010. There was no evidence of cracking in the tube ligaments, at the drain or the outlet nozzle.

Reheat inlet header and outlet headers on Unit 1 and 2 have not previously been inspected internally. The reheat outlet header (RH2) has been inspected on Unit 3 in 2003 and 2007. There was no evidence of ligament cracking.

Select secondary superheat outlet and reheat outlet headers stub tube welds are inspected as part of the annual inspection program on all units. Typically, no damage has been found.

5.3.2 Assessment

Economiser Headers and Link Piping

The economiser inlet header inspection was dropped from the 2012 scope. Based on the 2010 inlet header internal inspections the main potentially life limiting issue is the ligament cracking. The inlet tee crotch region indications are also of interest. The minor borehole cracking and axial indications in the Unit 2 inlet tee is common for boilers of this design and vintage.

The Units 1 and 2 inlet headers will need to be routinely inspected to monitor damage accumulation. Thermocouples were installed on the headers to provide the unit operators with guidance on start-up feed rates to control thermal gradients in the headers. The effectiveness of these actions should be reviewed. A critical crack size assessment should also be considered to support continued operation. Such an assessment would also define end of life if the crack growth rates cannot be controlled.

Inspections of the Unit 3 inlet header have been incomplete in that the most susceptible areas, the inlet end has not been inspected. Although there does not appear to be a thermal fatigue issue, and inspection of the full length of the header is recommended.

The Unit 3 link piping support issue needs to be investigated.

Waterwall Headers and Riser/Feeder Tubes

The Unit 2 lower waterwall header (H1) and two of the sidewall headers were visually inspected on the ID. No evidence of thermal or corrosion fatigue, or significant ID corrosion was detected. Based on this evidence and on the inspection history for the upper waterwall headers, these headers are not considered to be life limiting. A similar inspection for Unit 1 should be included in the routine monitoring program.

Visual inspection of a sample of riser tunes on Unit 1 identified axial scoring and random pitting, and several cases of extensive aligned pitting. There was no evidence of active cracking at the scoring or the aligned pits however, further investigation of the extent of damage is recommended for Unit 2 in 2013.

The pitting is the result of oxygen and water in the tubes during lay-up. Lay-up procedures have been recently updated. A review of the lay-up procedure application is recommended.

<u>Superheat Headers and Link Piping</u>

The Primary Superheat Outlet header (SH3), Secondary Superheat Inlet header (SH4) and link piping are located in the boiler penthouse. The secondary superheat outlet header is located in the header vestibule on the front of the boiler. All components are un-insulated.

The SH3 is fabricated from a low alloy steel (SA-335-P12) and does not operate at creep temperatures for that material. The SH3 also does not experience thermal fatigue from attemperator operation. As a result, the SH3 is a lower priority for life assessment.

The SH4 is fabricated from carbon steel (SA-106B), operates at creep temperatures and is subject to thermal cycling or thermal shock from the attemperators. Inspections of the Secondary Superheat (SH4) header and link piping containing attemperators were dropped from scope due to the time required for asbestos abatement. The planned inspections are recommended to assess the creep and thermal fatigue damage in the SH4, and potential seam weld creep issues in the link piping.

The SH5 header is also a low priority for life assessment due to materials of fabrication, and operating conditions that do not support creep or fatigue.

Inspections of the SH6 header, focussed on the nozzle welds, seam weld, girth welds, parent material on the header OD, and ligaments and other features on the header ID.

High temperature header seam welds can preferentially accumulate creep damage and represents a high hazard due to the length of the weld and potential energy release if failure were to occur. A section of the circumference of the header was etched to identify the weld and HAZ microstructure. No seam weld was found in the section that was etched. A full circumferential etch is considered necessary to confirm there is no seam weld microstructure.

The lack of a weld, a HAZ microstructure and weld cap can occur if the header was fully normalised (heat-treated) and machined on the OD and ID as part of the manufacturing process. The heat treatment can remove the preferentially creep susceptible microstructure, and eliminates the potentially life limiting issue. This is the likely case for Units 1 and 2 but has not been confirmed through inspection.

The ID visual inspection was to detect bore hole ligament, weld, and outlet nozzle ID creep and creep fatigue cracking, and thermal fatigue cracking at the drain. There was no visible evidence of cracking detected on the ID.

Initial MT inspections on the Unit 2 east nozzle weld, including the Heat Affected Zone (HAZ) and adjacent parent or base material detected macro-cracking the weld at the 6 and 12 o'clock positions, [R-9]. Cracking at the 12 o'clock position was removed with light grinding. The 6 o'clock position had approximately 8mm depth and was weld repaired. Follow-up on the west nozzle identified similar cracking in the 6 o'clock position. The cracking was removed by light grinding, indicating the damage was surface initiated. Weld repair was not required. MT on the Unit 1 SH6 nozzles identified damage in the weld extending into the header side HAZ at the east nozzle. The damage was removed by grinding and weld repaired. Wall thickness measurements indicate the header, and restored weld thicknesses were above the minimum wall specification.

Volumetric testing on both Unit 1 and 2 by Phased Array Ultrasonic Testing (PAUT), for sub-surface and ID defects in the welds and HAZ areas found no in-service damage.

Replication of representative areas of weld/HAZ/parent material was conducted to assess the condition of the microstructure, the nature of the cracking and to detect incipient creep damage (creep voids). The results indicate the microstructure has thermally degraded. The cracks on Unit 2 were in the weld material, and were not oriented with the primary stress. Further, the cracks were oxide filled, suggesting the cracks had existed for an extended period and were not growing. There was no strong evidence of creep damage. On Unit 1 the cracking was of similar morphology but extended into the HAZ, and was reported as creep.

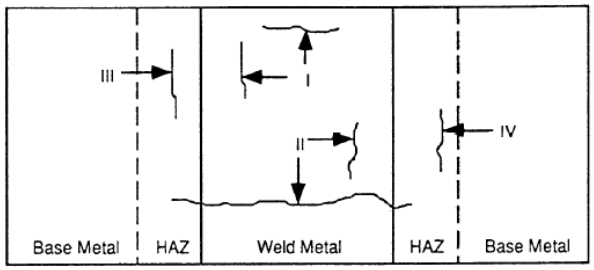
The ID visual inspection results also suggest there is no ID initiated creep damage.

Creep cracking in welds is classified as Type I or Type II creep. Type III and Type IV creep occurs in the course grain and fine grain HAZ respectively, Type V creep can be considered parent material creep, Figure 8. Type IV is considered most serious due to difficulties in detecting damage until near end of life. Type IV initiates mid-wall and by the time it is detected by conventional means, (MT, replication or conventional UT), the component is considered near failure. PAUT techniques and in particular focussed PAUT provide a significant enhancement in detectability. The NDE reports and replication report are contained in the reference binders [R-9, R-22]. Guidance on run/repair and reinspection intervals is provided in Reference 16.

Results of the inspection effort on the SH6 headers suggest the microstructure is thermally degraded and although it was concluded the damage on Unit 2 as a weld defect there is the possibility of early stages Type I and Type III creep.

Thermal degradation of the microstructure has no significant impact on material strength. The results also indicate that the material properties are not considered to have been significantly degraded. These findings and the wall thickness measurements in Section 4.4 indicated the remaining life predictions from Phase 1 are adequate, and the SH6 headers on Units 1 and 2 are expected to meet desired end of life. The review is contained in Appendix C [R-25].

Creep can be managed through inspection and repair. It is recommended Unit 2 nozzles be re-inspected by MPI in 2013, or at the next outage. Future inspections will be based on EPRI guidelines [R-16].



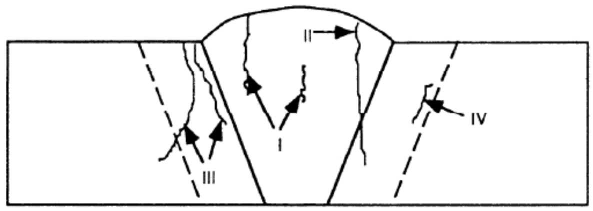


Figure 8 Classification of Creep by Location and Type (I, II, III, and IV) in High Temperature Thick Section Components [R-15]

Assuming the level of retained damage is Type III and damage level is oriented cavities, reinspection is required at intervals of 0.4t where t is operating hours at detection. Using Unit 2 Operating hours in October 2012 (168,122), the next inspection is required after 67,250 hours. Conservatively, an inspection regime based on alternate units every 3 years is recommended (repeat inspections per unit at 6 year intervals). This would result in intervals of approximately 30,000 hours for each of Unit 1 and 2.

In the course of the SH6 inspections, cracking was observed in the header stub tubes. This type of damage is typically due to fatigue and is related to differential expansion in the header and the width of the waterwall, and the distance, or flexibility in the tubing between the waterwall penetration and the header. Similar damage was found on Unit 1 in 2013. Both units have been repaired.

<u>Reheat Headers</u>

The reheat headers are located in the header vestibule at the front of the boiler. The headers are not insulated. The reheat attemperators are in the cold reheat piping and could affect the inlet header (RH1) but are not in service.

The cold reheat header (RH1) was inspected internally by boroscope for fatigue, thermal fatigue, thermal shock, and for evidence of corrosion. There was no evidence found of cracking, general corrosion or pitting. The cold reheat header does not operate in the creep temperature range, and was therefore not inspected for creep damage.

Based on the inspection results it is concluded there are no life limiting issues in the cold reheat header. A similar inspection on Units 1 and 3 is recommended. However, no further inspections are considered necessary on Unit 2 providing there is no significant change in operation. Use of reheat attemperators, or changes in boiler start procedures would constitute significant operating changes.

Hot reheat header (RH2) inspections on Unit 2 consisted of MT of the east outlet nozzle welds, and header supports for macro cracking, an ID boroscope inspection, phased array UT (PAUT) volumetric inspection on the east outlet nozzle, and etching to locate the header seam weld. Unit 1 inspections consisted of replication and etching to locate the seam weld.

It is to be noted that the RH2 outlet nozzle appearance is consistent with the header calculations drawing [R-17]; a forged tee, welded to the header pipe sections. This is different from the SH6 outlet nozzles which is a pipe to pipe branch connection with a full penetration fillet weld.

A grind and etch process was used on both Unit 2 and Unit 1 to locate the header seam weld microstructure. Only a limited area was etched on Unit 2 due to time and space restrictions. The weld could not be located, despite the location being indicated in the header drawing [R-18]. Another attempt on Unit 1 captured a larger area and resulted in the same conclusion that there was no evidence of a seam weld. The Unit 1 effort was restricted to about 270 ^{O} of the circumference by the cladding.

Similar to the SH6, the lack of a weld, a HAZ microstructure and weld cap can occur if the header was fully normalised (heat-treated) and machined on the OD and ID as part of the manufacturing process. The heat treatment can remove the preferentially creep susceptible microstructure.

The other NDE results all found no evidence of advanced level creep damage. There was no macro cracking in the girth welds or support welds, and the PAUT results indicate there is no advance mid-wall creep damage associated with the girth welds (Type I or IV in Figure 8). There was no indication of ID thermal fatigue or creep fatigue. Replication of the Unit 1 RH2 header identified spherodized carbides in ferrite, representing a thermally degraded microstructure, but no evidence of creep.

The RH2 is not included in the creep life calculations in Appendix C [R-25] due to a low Life Fraction Expended (LFE) result from the Phase 1 Assessment [R-1]. Using the EPRI methodology, components with a LFE less than 10% can be excluded from a Level 2 assessment. The Reheater Outlet Header had a LFE of 9.5% at projected end of unit life. This compares to a projected LFE of 79.5% for the SH6.

5.3.3 Actions

No capital reinvestment actions are considered necessary from the results of the 2012 or 2013 inspections. The following actions are recommended at the earliest opportunity:

- Inspection of the SH4 and the superheat link piping as described in the Phase 2 scope (Appendix A)
- A critical crack size analysis is recommended for the Units 1 and 2 economiser inlet headers.
- A complete inspection is required for the Unit 3 economizer inlet header. Reinspection is due for Units 1 and 2.
- The Unit 3 economizer link piping hanger issue identified in 2010 needs to be investigated further during the annual boiler inspection.

- The SH6 outlet nozzle weld repairs need to be re-inspected by MPI on Unit 2 in 2013 or at the next outage and Unit 1 in 2014. A full inspection regime of PAUT and replication is recommended for Unit 2 in 2015 (3 years from 2012 inspection), and Unit 1 in 2018 (or 2017 given the present operating plan – within 30,000 operating hours). Corrective action is required if accelerated or new damage is detected.
- Wall thickness measurements should be taken again in 3 years time to track wall loss due to high temperature oxidation on the SH6 and RH2 headers. This action is expected to be included in the header nozzle inspections.
- A full circumferential etch of both the SH6 and RH2 headers should be completed to ensure there is no creep susceptible seam weld microstructure on Units 1 and 2. Past difficulties in completing this action indicate the preparatory stages, location selection, and work scheduling needs to be carefully planned in advance.

5.4 Steam Piping

5.4.1 History

The steam piping at Holyrood consists of seamless low alloy CrMo (SA335-P22) materials on the main steam and hot reheat, and seamless carbon steel (SA106-GrB) on the cold reheat. Y fittings are utilised in all three steam piping systems, on all three units.

The reheat attemperators are not used.

Initial indications are that original support system on Units 1 and 2 was fully floating, consisting of constant load hangers with no snubbers. The main steam system on Units 1 and 2 was changed at some point with the addition of a variable load spring hanger in the main vertical run (at the main steam MS8 position). There are no records indicating the time or reason for the change.

Previous concerns over the configuration of the Hot Reheat supports at HR15 and HR17 have been clarified as being consistent with design based on turbine manufacturer, Canadian General Electric, drawing [R-27].

Unit 3 has a partially floating support system with rigid rod hangers at the lower Y connections.

The main issues that can affect reliability and safety can be grouped as follows:

Operating issues

- Thermal fatigue from condensate events related to operation of drains during starts, or incorrect operation of reheat attemperators (not currently used at HTGS).
- Pipe distortion or support damage from transient hammer events, causing changes in support system load distributions, or poor drainage, and potentially creep, fatigue, corrosion or a combination of each mechanism.
- Fatigue from high temperature ramp rates and unit starts.

- Accelerated creep from over temperature operation or at stress concentrations created from changes in supports (hangers) and piping load distribution. Bending stresses are particularly detrimental.

Design

- Creep – base degradation due to operation in the creep temperature range.
- Accelerated creep due to manufacturing process, particularly submerged arc weld (SAW) shop welds.
- Accelerated creep in Y fittings on the high temperature systems due to piping loads.
- Inadequate drain capacity or location resulting in possible condensate events leading to thermal fatigue or accelerated creep.
- Incorrect manufacturing heat treatment and tramp material contamination resulting temper embrittlement.
- Accelerated creep at gamma plugs, instrument ports and thermowells, and at hanger lug connections due to design configuration.

Maintenance

- Lack of, or incorrect maintenance of supports resulting load redistribution and accelerated creep or fatigue in cycling units.
- Lack or incorrect maintenance of valves controlling piping drains, or water supply to the attemperators.

Seasonal operation

- General ID corrosion and pitting.

Power process piping design is based on the requirements of the ASME Boiler and Pressure Vessel Code, B31.1, Power Piping. The integrity of the steam piping and damage accumulation is highly dependent on the correct design and operation of the support system. Incorrect behaviour of the support system can result in load redistribution and accelerated creep for piping operating in the creep range and fatigue in low temperature steam piping.

A review of the operating and maintenance history in the Phase 1 project indicted there have been no significant failures or reports of transient events prior to 2013 - hammer or condensate events. Operating data indicates temperatures are within specifications. In January 2013, a turbine trip event on Unit 1 caused significant physical shaking of the steam piping. Potential damage from this event was investigated as part of the Unit 1 assessment.

The cold reheat drains were replaced on Units 1 and 2 to address concerns raised by the machinery insurer, likely to reduce the chance of condensate events, causing thermal fatigue/shock cracking.

The boiler stop valve in the main steam line was replaced on Unit 2 in 2008. A piping analysis was done at the time to guide adjustments to the support system and to demonstrate compliance with AMSE B31.1, [R-19].

A second analysis was done for the Unit 2 main steam system with the new valve, to address changes in the valve weight, and to demonstrate B31.1 compliance.

In early 2013, a leak was detected at the above seat drain weld on the Unit 2 boiler stop valve. There is no specific information on the cause of the event other than an expectation that a combination of fatigue and creep was responsible. The repair included the installation of a hanger for the drain line to reduce the bending stresses on the weld.

Holyrood maintained a piping inspection program from 1989 to 2001. The program consisted of hanger inspection and periodic NDE including replication. It was discontinued after 2001.

Data available indicate the support system functioned reasonably well over the period of 1989 to 2001. A preliminary inspection of hangers during the Phase 1 project indicted there were minor issues but no broken hangers, major impact damage, distortion or other key indicators of problems. There are no reports of hanger adjustments other than adjustments associated with the boiler stop valve change on Unit 2.

NDE and replication from the 1989 to 2001 found no indications of advanced creep damage. It was reported that the main steam piping material microstructure was thermally degraded as indicated by spheroidization of carbides and migration to grain boundaries.

5.4.2 Assessment

The proposed scope of NDE work on steam piping was based on typical industry concerns, results of the original piping analysis indicating forces and moments, and the Phase 1 assessment that the support system had reasonable functionality. The 2013 NDE scope on Unit 1 accounted for support issues identified in 2012, and concerns over possible damage from the turbine trip event on Unit 1 in January 2013. Locations and results are summarized in Table 2.

NDE reports and the hanger inspection report are provided in the reference binder for Unit 2 [R-9], and Unit 1 [R-22].

<u>Cold Reheat</u>

The cold reheat inspections consisted of MT and PAUT at the east cold reheat header nozzle link on Unit 2 and the West boiler link, lower Y inlet and east turbine terminal point on Unit 1. The inspections were to detect fatigue cracking on the OD and ID cracking at either the weld root or counter bore notch. There was no damage found on either Unit 1 or Unit 2.

The hanger inspections from all three units determined the field configuration is consistent with the design, with the exception of the new drains on Units 1 and 2. There is no indication the new drains have adversely affected the support system. .

The cold reheat piping is not subject to creep. Based on the limited NDE results, it is expected the cold reheat piping on all three units will achieve desired life. Completion of the inspection scope planned in 2012 is recommended to support this conclusion.

<u>Main Steam</u>

Main steam piping inspections on Units 2 and 1 consisted of terminal points at the boiler and the turbine, major valve welds, a shop weld, various instrument penetrations and hanger lugs.

NDE consisted of MT for external macro cracking, PAUT for mid wall and ID defect detection and replication for incipient creep damage. The shop weld inspection was limited by access. Thickness measurements were taken to confirm data used for the remaining life analysis.

The PAUT inspections identified no subsurface flaws in the welds or HAZ of the inspected welds, indicative of advanced Type IV creep damage.

The replication confirmed the thermally degraded microstructure identified in the previous assessments. Cracking was found at the Unit 1 Boiler Stop Valve (BSV) inlet weld in a layer of low alloy weld material. This was removed by grinding. Creep cracking in the Unit 1 BSV is of limited consequence as there was sufficient material of the correct grade and without indication of advance deterioration to maintain integrity. For Unit 2 the BSV was replaced in 2008. The same weld would have been replaced at that time

The Unit 2 BSV drain line weld failure is considered to be a fatigue, or creep fatigue issue due to high system stresses on the weld. B&W recommended the installation of a hanger to relieve the system stresses. Inspection of the Unit 2 BSV inlet weld should be considered to addresses any concerns over the quality of the valve installation. Inspection of the Unit 1 drain line weld found no cracking. The event is likely the result of unanticipated loading from the Unit 2 BSV replacement in 2008. Unit 1 does not appear to be susceptible to the same problem.

The assessment of the replicas from the main steam weld at the west turbine flange on Unit 2concluded there was possible isolated cavities in the course grained zone of the weld HAZ. The location corresponds to Type III in Figure 8. Inspection of the Unit 1 west flange weld in 2013 found no cracking. Replicas from the Unit 1 east turbine terminal identified no creep.

There was no evidence of creep damage was found in the weld, HAZ or parent material at the other piping locations inspected. There were no indications to suggest significantly degraded creep rupture properties. However, there are concerns that the Unit 1 turbine trip event may have induced plastic strain (ratchetting) in the piping. Plastic strains will accelerate creep damage accumulation but will not be immediately evident. Susceptible locations are the Main Stop Valve outlet welds. It is recommended at least one of these welds be periodically inspected.

Industry practice to address creep damage is to monitor damage accumulation until repair is required, typically when macro cracks are evident [R-16]. It must be noted that Type IV and creep fatigue is treated differently; repair is usually required upon detection.

For creep Type I to III, replica inspection is required at decreasing intervals as damage progresses from isolated voids to dense voids to micro cracking. Considering the EPRI guidelines [R-16], and conservatively assuming a damage level of oriented cavities, a reinspection period of 0.4t (t is current operating hours) is recommended. For the Unit 2 main steam, 0.4t translates to an interval of 67000 operating hours. In the present application, reinspection is recommended at 3 years to confirm the results.

There was no evidence of damage on the Unit 1 main steam piping from the turbine trip event.

The gamma and instrument connections also showed no evidence of cracking. It is also to be noted that during the scope development it was found that the thermowell configuration consists of a Chromium-Molybdenum (CrMo) steel boss welded to the pipe and a stainless steel insert to the boss. The arrangement provides for a similar material weld between the pipe and the boss and significantly reduces the chance of premature failure compared to stainless steel thermowell welded directly to the pipe.

Results of the hanger inspections concluded there were no immediate impacts on main steam piping remaining life. A review of the Unit 2 main steam piping analysis at the time of the Boiler Stop Valve replacement concluded the support configuration with the MS8 change was code compliant. The "as-found" analysis addressed conditions before the new valve was installed, and with the modified support. This result implies the same configuration on Unit 1 would be acceptable.

The main steam piping is subject to creep. The wall thickness measurements in Section 4.4 indicate the wall thicknesses are greater than the minimum values used for the creep life assessment in Phase1. A sample assessment for the main steam piping using the current data is provided in Appendix C [R-26]. The results suggest the remaining life of the main steam piping extends beyond the 10-year planning window. Repeat wall thickness measurements are recommended at three years to track possible wall thickness loss due to high temperature corrosion. Completion of the planned Condition Assessment Phase 2 inspections is recommended.

<u>Hot Reheat</u>

Hot reheat piping inspections consisted of boiler and turbine terminal points, Y fittings, and both inlet and outlet samples of the Combined Stop Valves (CSVs), associated gamma plug and instrument connections, and hanger lug attachment. A larger number of sites were inspected on Unit 1 to identify damage created by the turbine trip event in January 2013. The increased scope on Unit 1 means the Phase 2 Condition Assessment inspection scope for the Hot Reheat Piping on Units 1 and 2 is complete.

NDE consisted of MT for external macro cracking, PAUT for mid wall and ID defect detection and replication for incipient creep damage. Thickness measurements were taken to confirm data used for the remaining life analysis. There were gaps in the thickness data and follow-up to obtain data from the main run off the boiler (20" OD), and the piping downstream of one of the combined stop valves (16" OD), is recommended.

There were no piping defects identified in any of the NDE results. This finding applied to the long term creep damage and the short term fatigue damage that could have resulted from the movement observed during the January turbine trip event on Unit 1. However, it does not account for long term impacts from plastic strains (ratchetting) that may have been induced in the hot reheat piping as a result of the turbine trip event. Induced strains will accelerate creep damage accumulation. The locations most susceptible are the downstream welds at the CSVs. Periodic inspection is recommended.

The replication confirmed the thermally degraded microstructure identified in the previous assessments conducted between 1999 and 2002 and noted in the Phase 1 report. No evidence of creep void formation was found in the weld, HAZ or parent material. The Y crotch replica identified a microstructure typical for a CrMo steel casting exposed to operating temperatures. There were no indications to suggest significantly degraded material properties that would alter the remaining life assessment.

The gamma and instrument connections also showed no evidence of cracking. Similar to the main steam the thermowell configuration consists of a CrMo boss welded to the pipe and a stainless steel insert to the boss. Again, the arrangement significantly reduces the chance of premature failure compared to stainless steel thermowell welded directly to the pipe.

The hanger lug connection consists of a lug welded to a pad, which is welded to the pipe. Damage is more often associated with lugs welded directly to the piping where thermal stresses created from the temperature difference between the lug and pipe will increase thermal stresses at the pipe weld. The Holyrood configuration inherently reduces the potential thermal stresses. The inspections indicate there is no macro damage at the hanger lug pad weld.

There were no significant issues identified in the hanger inspections that would affect immediate reheat piping remaining life. In addition, wall thickness measurements indicate the values are greater than the minimum values required thickness to achieve a remaining life greater than the 10-year planning window, Appendix C, [R-25]. Repeat wall thickness measurements are recommended to track possible wall thickness loss due to high temperature corrosion, and to improve the sample size.

<u>Hanger Assessment</u>

Hanger inspections in the hot and cold conditions were completed on all units. The results of the inspections are summarised in Appendix E. For additional details, reference should be made to the full report [R-26], in the reference binder [R-22]. Major findings and actions are identified below.

The hanger inspections found all hangers to be functional and in reasonable condition. There was no evidence of significant load redistribution, piping distortion (skewing), or sagging.

On all units, the majority of the hangers operated within acceptable loading ranges in the hot condition. This conclusion accepts that random topped out hangers and random bottomed out hangers in the cold condition are adequate but need to be monitored. Bottomed out hangers in the hot condition and hangers that do not register a position change between hot and cold need to be monitored for impacts on piping. Analysis and adjustment may be required if hangers are found to be non-functional. If there are concerns over the number of topped or bottom out hangers an analysis should be considered to guide adjustments. Significant adjustment of constant load hangers without a piping analysis is not advised.

A number of hangers were found to be either topped or bottomed out in the cold condition. This is more acceptable than in the hot condition but needs to be monitored.

The main configuration issue was the MS8 hanger replacement on the Units 1 and 2 main steam system. This change does not appear to adversely affect piping. Earlier configuration concerns at Hot Reheat supports HR15 and HR17 were further investigated in 2013 and found to be generally consistent with OEM design [R-27]. It is not know if the stanchion arrangement was used in the piping analysis but piping NDE and condition of other hangers does not suggest a problem.

Inspections of the Unit 1 supports for impacts from the turbine trip event identified a degraded condition at the support stanchions HR15 and HR17. The support stanchions are mounted on the concrete turbine pedestal. Both the concrete mount and the pipe connections were inspected for damage resulting from the turbine trip. The same location was inspected on Unit 2. No damage was found at the Unit 1 pipe connections but the concrete mount on Unit 1 was found to be in unsatisfactory condition: the concrete was spalling, several anchor bolts had failed and there was corrosion on the stanchion. A lesser degree of damage was noted on Unit 2. It is recommended the stanchions be replaced and the concrete repaired within a year.

Several hangers were noted as not registering the expected change in position from hot to cold condition. These hangers need to be monitored and the impacts assessed. Most notable is the MS10 hanger on both Units 1 and 2. Movement was noted at MS9 and MS11, and was anticipated at MS10 based on the piping analysis. This situation needs to be monitored.

There were a number of hangers with minor mechanical issues including missing lock nuts, evidence of corrosion, and several trapeze arrangements with distorted load distribution. The trapeze loading needs to be corrected. The other conditions can lead to hanger changes and should be monitored if not corrected.

There was no evidence of significant operating upsets, distortion or sagging. Minor damage to insulation was noted in several locations but was not considered significant to the point of affecting remaining life. These conditions also need to be routinely monitored particularly if there a significant increase in the number of starts. Operating upsets will typically occur during starts and shutdowns. A higher number of starts will increase the chance of such events.

5.4.3 Actions

Based on the available inspection data, the high-energy steam piping is expected to attain desired end of life. There are several issues to be addressed including possible creep damage in the main steam on Unit 2. Piping inspections also need to be completed on Unit 3. Specific recommendations are identified below.

- Complete the original Phase 2 Condition Assessment scope of work at the earliest opportunity with consideration of the results to date. This action includes obtaining thickness data from the Unit 1 or 2 Hot Reheat 20” OD, and 16” OD piping downstream from a combined stop valves.
- Re-inspect the Unit 2 main steam west turbine flange weld within 3 years of the last inspection (2015). The inspection is to include wall thickness measurements to detect wall thinning due to high temperature corrosion.

- Inspect the Boiler Stop valve inlet weld on Unit 2 in 2013, or the next outage.
- Reinspect one of either the east or west Main Steam Valve (MSV) outlet welds, and Combined Stop Valve (CSV) outlet welds on Unit 1 every 3 years from 2013 for accelerated creep damage. Consideration should be given to installing removable insulation on the selected locations to facilitate access to the welds.
- A high-energy steam piping management plan is recommended to track hanger condition, piping condition and possible operating upsets, and to guide piping inspections and life management activities. Hot and cold hanger inspection intervals of 2 years is recommended, starting in 2014.

  The piping program would also be expected to address and disposition the minor analysis and configuration issues identified in Appendix E, including the monitoring of pipe hangers in the topped or bottomed out condition, or those showing no movement. Conditions where multiple pipe hangers in a system are either topped or bottomed out should be considered for analysis to determine impact on the system piping stresses and load distribution, and on the other pipe hangers. In addition, manufacturer specifications for the pipe hanger should be consulted.
- Review and corrective action is recommended to address minor mechanical issues and to balance loads on the trapeze hangers.
- Repair or replace the stanchions and repair concrete in the Unit 1 hot reheat piping support system at HR15 and HR17.

5.5 Feedwater Piping

5.5.1 History

The feed water piping consists of condensate and feedwater piping, (High Pressure (HP) and Low Pressure (LP) feedwater), low flow piping, superheat attemperator piping boiler feed pump recirculation piping, and feed water heater vent and drain piping. The commonality is exposure to single phase process water, and low quality process steam.

The primary failure and life degradation concerns are as follows:

Operations

- Thermal fatigue and thermally driven corrosion fatigue due to high start-up feed water feed practice.
- Fatigue and mechanical damage due to hammer transients.

Design

- Flow accelerated corrosion (FAC) due to a combination of water chemistry, system metallurgy (materials of construction), process conditions (temperature), and pipe geometric factors.
- Erosion in elbows and pipe downstream of valves due to two phase flow.

Maintenance

- Incorrect or lack of maintenance of flow control valves resulting in thermal fatigue. (same concerns applies to economizer inlet header).

Seasonal Operation

- General corrosion and pitting due to incorrect lay-up of piping

Holyrood process water chemistry is classified as low oxygen, All Volatile Treatment – Reducing (AVT-R), which supports FAC. Chemical injection is at the condensate extraction pumps which will make the low pressure feed water piping susceptible to FAC in addition the HP pressure feed water piping. A review of the water treatment practices subsequent to the hydrogen damage events in the Unit 2 waterwall tubing did not address FAC susceptibility.

Holyrood has a basic wall thinning monitoring program consisting of periodic wall thickness measurements at designated locations, usually elbows. Point measurements are taken at the same location and the difference is monitored over time.

There are no reports of water hammer events and inspections during the Phase 1 project did not identify evidence of significant mechanical damage (distorted piping or damaged pipe insulation).

Thermal fatigue, or thermally driven corrosion fatigue has not been monitored, and there are no reports of reliability issues with the low feedwater flow control components. However, recent inspection of economiser inlet headers on Units 1 and 2 suggest conditions that could lead to thermal fatigue cracking in the feed water piping, typically in welds at elbows or in the thick section valves, isolation valves and Non-Return Valves (NRVs), may occur. These situations are typically managed through periodic inspection and repair.

There are no reports of corrosion during lay-up being an integrity issue for feedwater piping. Lay-up guidelines have also been recently reviewed and updated. This would be expected to reduce the chance of significant corrosion when implemented.

5.5.2 Assessment

The Holyrood wall thinning monitoring program does not constitute a FAC control program. FAC will be found in elbows, but the most significant effects are in the piping up and down stream of the fittings. FAC also occurs over an area of pipe, and may not be fully realised through single point measurements. Industry practice [R-20] includes monitoring, typically consisting of mapping wall thickness around the circumference of the pipe 2 to 3 pipe diameters on either side of the fittings.

The planned FAC inspections were to identify the existence of FAC, and severity of the damage. Locations were selected based on industry and Holyrood operating experience, and represented areas of greatest consequence in the event of failure.

FAC inspections in 2012 were completed in the superheat attemperator flow element and valve station, one location in the HP feed water and a location in the LP feedwater. Results are reported in Table 2, and a summary report is provided in Appendix D. Wall thickness NDE reports are contained in the project reference binder [R-9]. There were no feedwater piping inspections on Unit 1 due to funding constraints.

FAC was not detected at the attemperator valve station or the LP Feedwater piping. The location in the HP feed water, downstream of the double elbow exit from the #4 feedwater heater, did show evidence of FAC. The sinusoidal pattern of the wall thicknesses is typical of FAC damage (see report in Appendix D). Reinspection of the pipe downstream of the #4 feedwater heater is recommended at 7 years, or 28,000 operating hours.

Wall thinning was noted down stream of valve 2TV619C in the superheat attemperator valve station. The thinning is considered the result of erosion. Re-inspection in 3years (2015) is recommended to assess the wall thinning rate. There are also informal reports of chrome-moly (CrMo) steels being installed at locations in the attemperator piping. If this is the case, the chromium will significantly inhibit FAC. The presence of chromium can be checked with a portable material tester with appropriate precautions. Attempts to check material content were not successful in 2012. It is recommended the process be reviewed and another attempt made. Verification of high chromium content will explain the lack of FAC evidence, and can reduce future monitoring needs. LP feedwater piping inspections found no evidence of FAC. This is one location but indicates the LP feedwater piping can be treated as a lower priority compared to the HP feedwater piping.

The FAC inspection results are based on a small data set. Several of the high priority locations in the HP Feedwater piping were not inspected. Completion of the planned inspections is recommended to improve the life and reliability assessment.

The planned inspection of HP pipe fittings for thermal fatigue was not completed. As noted, the damage found in the economizer inlet header suggests thermal fatigue may occur in the feedwater piping as well. Completion of the planned inspection is recommended. This issue will become more important if the units start to see increased starts. Also related will be the proper use and maintenance of the low flow control system and monitoring of economiser inlet header temperature gradients as an indication of thermal transients in the feedwater piping.

5.5.3 Actions

As described, FAC and thermal fatigue are likely active mechanisms in the Holyrood HP feedwater piping and related subsystems. It is recommended the original scope of inspections be completed on the three units to improve confidence in the overall assessment. As an alternative, an FAC engineering assessment can be conducted to provide greater targeting for inspections and to consider options to correct or minimise the impacts of FAC.

It is also recommended that a susceptibility analysis be conducted and a FAC program be developed and implemented. FAC is not a life limiting issue, but must be managed to minimise the reliability and safety risk. The erosion location in the superheat attemperator piping down stream of 2TV619C can be included in the FAC program or monitored under the existing wall thinning program at Holyrood, but it is recommended the site be subject to routine monitoring. The program should include a material testing survey. A review of previous material testing efforts is recommended to ensure valid results are obtained.

It is also recommended a review of operating procedures and practices be conducted to assess start-up practices and the use of low flow control (trickle feed), and thermocouple on the economizer inlet headers for controlling thermal gradients in the economiser inlet header and feedwater piping.

6.0 CONDITION AND RISK SUMMARY

The following table summarizes component level condition and technical and safety risk for the components addressed in the current report for Holyrood TGS Units 1 and 2. With the units being essentially identical in design and operating experience, Table 3 addresses each component by component type, where life issues and risk would apply to both units. The exception to this is the Condensate and Feedwater piping. Work completed was on Unit 2 only. The Feedwater piping risks presented are for Unit 2 only.

Where identified, asset designation is provided based on the asset register identified in the Phase 1 final report [R-1].

Asset Register

Asset Class:	1296 BU
Asset Level 2	7635 #2 (Unit 2), 6690 #1 (Unit 1)
Asset Level 3:	Boiler Plant -7786 #2, 6899 #1
	Condensate and Feedwater Plant – 7978 #2

Asset number beyond Level 3 is provided in the table in the format of Unit 2/Unit 1.

It has been concluded in the assessment that based on the present information, there are no end-of-life issues or capital requirements for the boiler and feedwater plant to achieve desired life. Remaining life in Table 4 is identified as 10 years in order to bound the present operating plan identified in Section 2.

This conclusion is based on the assumption that design parameters are maintained, and correct operating procedures are followed.

For each risk ranking, the expected failure event is described. Mitigating actions are also described. The actions are intended to reflect the component level recommendations in Section 7.

Table 4 Condition Summary and Risk Assessment

Asset # 4	Asset # 5	Asset # 6	Asset 3/4	Description	Component	Major Issues	Remaining Life Years[1] (Insufficient Info - Inspection Required)	Remaining Life Comments	TECHNO-ECO RISK ASSESSMENT MODEL Likeli-hood	Conse-quence	Risk Level	SAFETY RISK ASSESSMENT MODEL Likeli-hood	Conse-quence	Safety Risk	Possible Failure Event	Mitigation
Units 1 and 2 Boiler Plant (Asset #3: 7786)																
7789/ 6871	0	0	BOILER FW & SAT'D STEAM SYS	BOILER FW & SAT'D STEAM SYS	Upper WW Headers	Thermal fatigue cracking, corrosion-fatigue cracking in flat end welds, corrosion.	10	No cracking was detected Will meet the desired life with routine inspections	1	B	Low	2	B	Low	Flat end weld cracking. Wall thinning due to corrosion. Leak, Unit outage. Safety.	Routine inspections.
7789/ 6871	0	0	BOILER FW & SAT'D STEAM SYS	BOILER FW & SAT'D STEAM SYS	Riser Tubes	Corrosion, corrosion fatigue.	(10)	Inspections are required to assess the remaining life.	3	B	Medium	2	C	Medium	Pitting due to corrosion, and cracking due to corrosion fatigue Rupture, Unit outage. Safety.	Inspections are required to assess remaining life.
7789/ 6871	0	0	BOILER FW & SAT'D STEAM SYS	BOILER FW & SAT'D STEAM SYS	Lower WW Headers	Thermal fatigue cracking, corrosion-fatigue cracking, corrosion.	10	No cracking or significant cracking detected	1	B	Low	2	B	Low	Ligament cracking and weld cracking. Leak, Unit outage.	Routine inspections.
7789/ 6871	0	0	BOILER FW & SAT'D STEAM SYS	BOILER FW & SAT'D STEAM SYS	Feeder Tubes	Corrosion, corrosion fatigue.	10	No cracking detected	2	A	Low	2	A	Low	Corrosion fatigue cracking and wall thinning due to corrosion. Leak, Unit outage.	Routine inspections.
7789/ 6871	0	0	BOILER FW & SAT'D STEAM SYS	BOILER FW & SAT'D STEAM SYS	Downcomers	Thermal/mechanical fatigue cracking at the header support locations.	(10)	Inspections are required to assess the remaining life.	3	B	Medium	3	B	Medium	Thermal/Mechanical Fatigue Cracking at the header support locations. Unit outage. Safety.	Inspections are required to assess remaining life.
7789/ 6871-	0	0	BOILER FW & SAT'D STEAM SYS	BOILER FW & SAT'D STEAM SYS	Waterwall Tubes	Corrosion fatigue, thermal/mechanical fatigue, waterside under-deposit corrosion, short-term overheats, fireside corrosion.	10	No corrosion fatigue detected Pitting in some areas require attention, other than that no major life limiting issue observed.	2	B	Low	3	B	Medium	Extensive pitting or cracking leading to tube failure. Unit derate/outage.	Some sections of floor tubes and pitting in some areas require attention.
7789/ 6871	7790/ 6869	0	BOILER FW & SAT'D STEAM SYS	BOILER ECONOMIZER	Economizer Inlet Headers	Thermal/mechanical fatigue cracking, corrosion fatigue cracking, corrosion, FAC.	10	Thermal corrosion fatigue detected	3	C	Medium	3	B	Medium	Ligament cracking, tube stub thinning/cracking, weld cracking. Leak and extended unit outage.	Critical crack depth and routine inspections required
7789/ 6871	7790/ 6869	0	BOILER FW & SAT'D STEAM SYS	BOILER ECONOMIZER	Economizer Tubes	External corrosion and corrosion fatigue.	(10)	Inspections are required to assess the remaining life.	3	B	Medium	4	B	Med	Tube failure due to corrosion, corrosion-fatigue. Extended Unit outage	Inspections are required to assess remaining life.

[1] It is assumed the units have and will continue to be operated within limits (temperatures and pressures) specified by operating procedures.

Asset # 4	Asset # 5	Asset # 6	Asset 3/4	Description	Component	Major Issues	Remaining Life Years[1] (Insufficient Info - Inspection Required)	Remaining Life Comments	TECHNO-ECO RISK ASSESSMENT MODEL Likeli-hood	Conse-quence	Risk Level	SAFETY RISK ASSESSMENT MODEL Likeli-hood	Conse-quence	Safety Risk	Possible Failure Event	Mitigation
7789/ 6871	7794/ 6870	0	BOILER FW & SAT'D STEAM SYS	BOILER STEAM DRUM	Steam Drum	Thermal fatigue cracking, corrosion-fatigue cracking.	10	Thermal fatigue cracking found at downcomer nozzles.	1	C	Low	1	C	Low	Ligament cracking. Weld cracking. Unit outage and life safety.	Routine inspections to monitor creaking the downcomer nozzles
7810/ 6702	7811/ 6873	0	BOILER SUPERHEATER & REHEAT	BOILER PRIMARY SUPERHEATER	SH Front Support Tube Inlet Header SH4	Creep and thermal fatigue. Projected life fraction expended 4% in 2009	(10)	Inspections required assessing evidence of creep or thermal fatigue damage.	2	C	Medium	2	D	Medium	Creep and thermal fatigue cracking. Outage and life safety.	Complete requested inspections to determine if mechanisms are active, and update remaining life.
7810/ 6702	7811/ 6873	0	BOILER SUPERHEATER & REHEAT	BOILER PRIMARY SUPERHEATER	SH Front Horizontal Space Outlet Header SH6	Creep and thermal fatigue. Projected life fraction expended 80% in 2009	10	No creep or thermal fatigue detected. Possible in-service damage in nozzle welds	1	D	Medium	1	C	Low	Creep and thermal fatigue cracking causing a leak Outage and safety.	Routine inspections required
7810/ 6702	7813/ 6873	0	BOILER SUPERHEATER & REHEAT	BOILER SUPERHEATER ATTEMP'R	Superheater Link Piping and Attemperator	Thermal fatigue, creep and creep fatigue, corrosion. Life fraction low assuming seam less pipe	(10)	Investigate possible seam welded pipe . Additional inspections required.	3	D	High	3	D	High	Rupture of pipe seam weld	Additional inspections required.
7810/ 6702	7835/ 6878	0	BOILER SUPERHEATER & REHEAT	BOILER REHEATER	Reheater Inlet Header RH1	Thermal fatigue,	10	No evidence of cracking Could meet the desired life with routine inspections.	1	C	Low	1	C	Low	Thermal fatigue cracking. Outage and life safety.	Routine inspections
7810/ 6702	7835/ 6878	0	BOILER SUPERHEATER & REHEAT	BOILER REHEATER	Reheater Outlet Header RH2	Creep and thermal fatigue.	10	No evidence of severe creep .	1	D	Low	1	D	Low	Creep and thermal fatigue cracking causing a leak Outage and life safety.	Inspect and maintain.
7810/ 6702	7823/ 6876	0	BOILER SUPERHEATER & REHEAT	BOILER MAIN STEAM LINES	Main Steam	Thermal/mechanical fatigue, creep, creep fatigue, corrosion.	10	Creep life fraction expended is high (more than 60% at the end of 2009). No evidence of upset or thermal fatigue. No major damage found during walkdowns. Walkdown summary part describes specific observations.	1	D	Medium	2	C	Medium	Creep cracking resulting in leak. Outage and life safety.	Piping and Hanger inspection program required.
Units 2 Condensate and Feedwater System (Asset #3: 7978)																
8800	0	0	CONDENSATE EXTRACTION SYST	CONDENSATE EXTRACTION SYST	CE Piping/Valves	Flow Accelerated Corrosion(FAC), Weld failure, rupture.	10	No evidence of FAC	1	C	Low	1	C	Low	Piping rupture, outage and potentially fatal safety event.	Susceptibility analysis and inspection management program required
8037	0	0	BOILER FEEDWATER PUMPING	BOILER FEEDWATER PUMPING	Feedwater Discharge	Flow Accelerated Corrosion (FAC), thermal/mechanical fatigue cracking, corrosion-fatigue cracking; corrosion.	(10)	Evidence of Flow Accelerated Corrosion (FAC). Inspections incomplete	3	D	High	3	D	High	Piping rupture, outage and potentially fatal safety event.	Susceptibility analysis and inspection management program required

7.0 RECOMMENDATIONS

The original 2012 Phase 2 Condition Assessment and Life Extension Study was to focus on boiler and high-energy piping issues on Units 1, 2, and 3. Part of the Unit 2 investigations was completed in 2012. Unit 1 investigations were conducted in April 2013. Steam piping hanger inspections were completed on all three units between 2012 and April 2013. Completed versus planned NDE scope is identified in Appendix A. Additional inspections were conducted on Unit 1 to investigate the impact of extensive movement in the steam piping during a turbine trip event in January 2013.

From the work completed on Units 1 and 2, it is concluded that for the systems examined, there are no life-limiting issues, and no major capital expenditure requirements to achieve the desired operating life (2020). However, there are issues that will need to be managed to achieve the desired safety and reliability performance. It must be noted that the planned inspections were not completed for all identified components and these conclusions are based on specific inspections on Units 1 and 2 only.

The recommendations below are based on results of the assessment in Section 5 and the risk assessment in Section 6. Actions are recommended at the earliest opportunity unless stated otherwise below.

1. The planned Phase 2 boiler and high-energy piping condition and life assessment scope of work needs to be completed – identified in Appendix A. The scope can be adjusted to account for the work completed in 2012 and 2013 inspection results and with consideration of the discussion in Section 5. The following specific items should be included:
    a. Unit 1 and 2 economizer inlet headers
    b. Unit 1 or 2 boiler superheat crossover piping
    c. Unit 1 or 2 SH4 girth weld and internal visual inspection
    d. Wall thickness measurements on either Unit 1 or 2 Hot Reheat 20" OD, and 16"
    e. Unit 3 Boiler scope (Appendix A), and:
        i. Inspection of the Unit 3 economiser link piping supports
        ii. Steam drum inspection
    f. Circumferential etch of the SH6, RH2 headers and the superheat link piping for evidence of a seam weld microstructure, on either Unit 1 or Unit 2
2. In addition to the life assessment scope identified above, it is recommended the specific locations listed below be inspected in 2013 as follow-up to the damage identified in 2012.
    a. Unit 2 SH6 header east and west outlet nozzles are to be inspected for surface defects in 2013 to confirm no recurring damage accumulation.

       Routine inspection of the SH6 nozzle welds for creep damage is to be conducted on each of Unit 1 and Unit 2 every 6 years, alternating between units (one unit every 3 years) starting on Unit 2 in 2015 (3 years from 2012 inspections). The next inspection would be conducted in Unit 1 in 2018, or

2017 given the possible operating hours in measurements to detect any impacts of corrosion.

b. Unit 2 main steam piping west turbine flange weld at 6 year intervals. The inspection methods are to include replica, PAUT and MPI, starting in 2015.

c. A sample of riser tubes is to be inspected on either Units 1 or2 to assess severity of pitting and potential axial cracking before 2015

d. Re-inspect one of either the east or west Main Steam Valve (MSV) outlet welds, and Combined Stop Valve (CSV) outlet welds on Unit 1 every 3 years starting in 2016, for accelerated creep damage due to plastic strains created by the trip event. Consideration should be given to installing removable insulation on the selected locations to facilitate access to the welds.

e. Repairs are required within one year at the Unit 1 Hot Reheat supports HR15 and HR17; concrete and mounting plate repairs at the base of the stanchions and possible replacement of the stanchion.

f. Periodic inspection of a downcomer nozzle inside the steam drum needs to be implemented. One end (one downcomer) every 3 years, alternating ends is recommended for both Units 1 and 2, starting in 2015.

g. Inspect the Boiler Stop valve inlet weld on Unit 2 at the next available opportunity, for evidence of creep damage

3. An engineering analysis to define critical crack size and growth rate is recommended for the Units 1 and 2 economiser inlet headers (one assessment covering both units) as a basis for continued operation without repair, and to define end of life. The need for a similar analysis for Unit 3 will depend on the inspection results recommended in Item 1.
4. A review of unit start operating practices is recommended to ensure measures to limit thermal cycles are being effectively implemented.
5. A review of unit lay-up practices is recommended to ensure measures to limit corrosion and pitting of boiler and piping components are being effectively implemented.
6. A FAC susceptibility analysis and management program consistent with industry practice is recommended to assess the full scope of FAC in the Holyrood units, to identify opportunities to mitigate damage accumulation, and to manage integrity implications. The susceptibility analysis can also include a review of cycle water chemistry control practices. The action needs to include monitoring of piping thinning in the superheat attemperator water supply piping at valve 2TV619C on Unit 2 in 2015.
7. A hanger inspection and high-energy steam piping management program is recommended to monitor damage accumulation in the piping and condition of the supports to manage steam piping performance over the desired remaining life of the units. The inspections would include wall thickness measurements to assess wall loss due to high temperature corrosion, in 2015. Additional specific actions are:

   a. Review and corrective action is recommended to address minor mechanical issues and to balance loads on the trapeze hangers.

b. Monitor pipe hangers in the topped or bottomed out condition, or showing no movement. Conditions where multiple pipe hangers in a system are either topped or bottomed out should be considered for analysis to determine impact on the system piping stresses and load distribution, and on the other pipe hangers. In addition, manufacturer specifications for the pipe hanger should be consulted. Further details are provided in Appendix E.

It is also recommended that the results of the Level II assessment and life management strategies be integrated with the annual boiler and high-energy piping maintenance program. A new boiler maintenance program was developed by Alstom. A review and optimisation of the program to accommodate the results of the Level II assessment will help ensure desired performance is achieved. This action should also consider the effects of increased unit starts, and cycle water chemistry control performance. Periodic (3 year) removal of waterwall tube samples from high heat flux elevations needs to be part of the on-going boiler management program.

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Appendix A: Holyrood TGS Level II Condition Assessment – 2012 NDE Scope[1]

Sub-component	Issue	Locations for Inspection	NDE Method						NDE Comment	Comments Findings
			MT	UT	Replica	PAUT[2]	RT	Visual		
Unit 1 and 2 Boiler										
Waterwall tubes	• ID Corrosion Fatigue cracking	Cold side attachments • Top of burner Cor 2 • Buckstay corner Elev 59’-10’ Cor 1 • Buckstay cor at Rear wall, elev 64’-10”, cor 3 • Side wall/ slope at buckstay, elev 26’-11” west wall					X		RT from outside of boiler (film on boiler interior)	No indications of ID cracking
Waterwall Risers (penthouse)	• ID Corr Fatigue at neutral axis of bends	Sample of 10 risers identified by inspection • Bends for cracking		X				X	• Boroscope from inside drum for ID cracking in neutral axis (90^o & 270^o)	
	• Oxygen pitting	• Horizontal sections for pitting					X		• Pitting in horizontal sections (sagging) • RT for pitting	
	• OD Fatigue at nozzles		X						• External MT at drum weld	
Boiler Drum	• General fitness • Thermal fatigue cracking	General visual of drum internal for major damage (remove internals and baffles)						X	• General visual •	Only cyclones removed No unusual indications
		Riser and sat steam nozzles at drum ID	X					X	• 3 sections, about 10% each, selected during general visual inspection • Internal visual of risers (boroscope)	

[1] Shaded areas identify inspections completed in 2012/13 to date
[2] PAUT = Focused Phased Array and TOFT/Linear Phased Array

Sub-component	Issue	Locations for Inspection	NDE Method						NDE Comment	Comments Findings
			MT	UT	Replica	PAUT[2]	RT	Visual		
		Seam welds (sample sections)	X						• 1m section of lower and upper axial seam alternative between courses • 1m sections of circ welds including T, top and bottom , alternating between courses	Upper Seam weld
		Downcomer penetrations	X						Inaccessible internal areas Inside drum	Thermal fatigue cracking found at all four downcomers
		Drum Head Penetrations and Shell	X	X					• MT of penetrations • UT wall thickness of shell and heads	Part of annual survey Minor findings consistent with previous inspections.
		Boroscope ID of safety valve internal						X	Boroscope of nozzle ID to exterior of drum	
Downcomer	Thermal fatigue on ID	Downcomer to H1 header nozzle welds		X		X		X	Boroscope inspection of H1 ID Linear PUAT of 2 dwncr to H1	ID Visual inspection complete
		Downcomer to steam drum nozzle welds	X					X	50% from inside drum (2 downcomers) Inspect weld 0.5m down from Drum ID	
		Header Support Welds (50%)	X							
Ec Inlet Hdr	• Corrosion fatigue (circ) cracking in stub tubes • Thermal fatigue on ID of header • FAC in header or stub tubes	Inlet Hdr stub tubes First, last and middle 5 tubes (15 total)		X		X			Shear wave (PAUT) on tubes for circ ID cracking & thickness measurement	
		Inlet header (post-cleaning)				X		X	UT as required to size defects Boroscope on ID	Inspection cancelled based on 2010 results and plan to Reinspect in 2013
SH4	• Thermal fatigue cracking on the ID	Inspect Girth weld	X	X	X	X		X	1 circ weld UT – Thickness Linear PAUT of weld Focused PAUT as required, at least one replica	

Sub-component	**Issue**	**Locations for Inspection**	**NDE Method**						**NDE Comment**	**Comments** **Findings**
			MT	UT	Replica	PAUT[2]	RT	Visual		
	• Creep in weld	Visual inspection of ID, for macro cracking						X	Boroscope of ID	
Link Piping	• Creep in seam weld	Piping downstream of attemperator Penthouse access needed may require type 3 asbestos abatement.	X	X	X	X			Etch 2 pipes to assess if seam welded If seam welded, inspect seam (50%) Liner PAUT and Focused PAUT if anomalies found, replica and wall thick	
Main steam header (SH6)	Creep/ Creep Fatigue	Header thickness		X					Measure between circ welds	Access and cleaning of Header and supports
		Header ID visual						X	Boroscope of ID (ligaments, drain, nozzle)	Remove handhole cap No relevant indications. Findings supported by inspection in 2010
		Header girth welds (50%) At least one weld without a nozzle – to be confirmed on dwgs	X		X	X			Thickness + Linear PAUT of weld +1 replica – more if anomalies found	Low priority due to construction – only girth welds are external to boiler. Main concern is nozzle welds
		Header head seam welds (50%)	X		X	X			3 sections of hdr comprising 50% of length – etch if necessary to locate Lear PAUT of target length Focused PAUT of anomalies + 3 sample locations	Partial etch done to locate weld. No weld located Full circ etch required
		Header outlet nozzle welds (50% - 1 nozzle)	X	X	X	X			Thickness + Linear PAUT of weld +1 replica – more if anomalies found	Damage found in both east and west nozzle welds
		Header supports (50%)	X							
	Thermal fatigue	Drain (also seem to act as a vent. Inspect at weld to hdr in hdr vestibule)	X						External welds Interior thermal fatigue should be evident from boroscope inspection	
CRH Header	Thermal fatigue	CRH Header Internals						X	Boroscope ID through handhole cap	No relevant indications identified

Sub-component	Issue	Locations for Inspection	NDE Method						NDE Comment	Comments Findings
			MT	UT	Replica	PAUT[2]	RT	Visual		
HRH Header	Update creep life estimate	Header thickness		X					Between circ welds	
	Creep/ Creep Fatigue	HRH Header Internal						X	Boroscope	No relevant indications identified
		Header Supports (50%)	X							No relevant indications identified
		Header Girth Welds (50%)	X		X	X			Thickness + Linear PAUT of weld +1 replica – more if anomalies found	No relevant indications Replication not completed
		Header Seam Welds (50%) PAUT as req'd to size indications	X	X	X	X			3 sections of hdr comprising 50% of length – etch if necessary to locate Linear PAUT of target length Focused PAUT of anomalies + 3 sample locations at least 1 replica	Partial etch completed. No weld identified. Full circ etch required
		Header outlet nozzle welds (%50)	X	X	X	X			Thickness + Linear PAUT of weld +1 replica – more if anomalies found	East nozzle inspected. No relevant indications identified Replication not completed
Reheat Tubes	Creep-type damage in Dissimilar Metal Weld	Remove two dissimilar metal welds from Reheat outlet bank							Destructive metallurgical analysis	Tubes containing welds to be replaced due to ID off-line corrosion
Unit 3 Boiler										
Penthouse Riser Tubes.	Corrosion fatigue in neutral axis of bend	Inspect select short radius bends				X			10 risers at bends, 1' section, selected by inspection and RT for pitting External MT at drum weld	
	Oxygen Pitting	Inspect sample horizontal sections					X		Sample feeders to be selected by inspection – look for ID pitting in lower half of feeder	
	Fatigue	Inspect sample nozzle welds at steam drum	X						10 riser nozzles – same feeders as selected for bend inspection	

Sub-component	Issue	Locations for Inspection	NDE Method						NDE Comment	Comments Findings
			MT	UT	Replica	PAUT[2]	RT	Visual		
Lower Downcomer Header	Thermal fatigue at bore holes	One header (east or west)		X				X	Wall thickness and internal boroscope	
Lower WW Header	Thermal fatigue	One header internal visual inspection at bore holes and at flat end plug weld		X				X	Wall thickness and internal boroscope.	
Superheat Link Piping	Creep in seam weld	Piping downstream of attemperator	X	X	X	X			Etch 2 pipes to assess if seam welded If seam welded, inspect seam (50%) Liner PAUT and Focused PAUT if anomalies found, replica and wall thick	
Unit 1 Main Steam Piping										
West Boiler Link	Creep & Creep Fatigue	• Girth Weld • Thermowell • Gamma plug	X	X	X	X		X	MT on Gamma plug and thermowell MT, PAUT, UT, Replica on girth weld	
Shop Weld Above Stop Valve	Creep & Creep Fatigue	• Shop Weld above BSV • Instrument penetrations	X	X	X	X		X	MT on Gamma plug and thermowell MT, PAUT, UT, Replica on girth weld	
Boiler Stop Valve Inlet weld	Creep & Creep Fatigue	• Boiler Stop Valve, upstream weld • Gamma plug • Hanger lugs • Drain	X	X	X	X		X	MT on Gamma plug hanger lug, drain and thermowell MT, PAUT, UT, Replica on girth weld	
Main Stop Valve Inlet	Creep & Creep Fatigue	• Girth Weld • Drain & Gamma plug	X	X	X	X		X	MT on Gamma plug and drain MT, PAUT, UT, Replica on girth weld	
East Turbine Gov Valve Terminal	Creep & Creep Fatigue	• Flange Weld	X	X	X	X		X	MT, PAUT, UT, Replica on girth weld	Not a flange

Sub-component	Issue	Locations for Inspection	NDE Method						NDE Comment	Comments Findings
			MT	UT	Replica	PAUT[2]	RT	Visual		
Unit 1 Hot Reheat Piping										
West Boiler Link	Creep & Creep Fatigue	• Girth Weld • Thermo Well • Gamma plug	X	X	X	X		X	MT on Gamma plug and thermowell MT, PAUT, UT, Replica on girth weld	
Lower Y Inlet	Creep & Creep Fatigue	• Girth Weld • Hanger lugs • Gamma plug	X	X	X	X		X	MT on Gamma plug and thermowell MT, PAUT, UT, Replica on girth weld	**Thickness data is required**
East CSV Inlet	Creep & Creep Fatigue	• Girth Weld • Drain	X	X	X	X		X	MT on drain MT, PAUT, UT, Replica on girth weld	
East Turb Terminal	Creep & Creep Fatigue	• Flange Weld (Under Turbine)	X	X	X	X		X	MT, PAUT, UT, Replica on girth weld	
Unit 1 Cold Reheat Piping										
West Boiler Link	Fatigue	• Girth Weld OD and ID	X	X		X		X	MT, UT and PAUT on Weld Looking for ID fatigue cracking	
Lower Y Inlet, & Hanger Lug	Fatigue	• Girth Weld • Hanger Lug above Y	X	X		X		X	MT, UT and PAUT on Weld, MT on lug	
West Turbine Terminal	Fatigue	• Flange Weld	X	X		X		X	MT, UT and PAUT on Weld Looking for ID fatigue cracking	
Unit 2 Main Steam Piping										
East Boiler Link	Creep & Creep Fatigue	• Girth Weld • Thermowell • Gamma plug	X	X	X	X		X	MT on Gamma plug and thermowell MT, PAUT, UT, Replica on girth weld	No evidence of creep voids
Upper Y East Side	Creep & Creep Fatigue	• Upper Y East Inlet Weld • Crotch of Y • East Hanger Lug • Gamma plug	X	X	X	X		X	MT on Gamma plug and thermowell MT, PAUT, UT, Replica on	

Sub-component	Issue	Locations for Inspection	NDE Method						NDE Comment	Comments Findings
			MT	UT	Replica	PAUT[2]	RT	Visual		
									girth weld, and Y crotch	
West Main Stop Valve Outlet	Creep & Creep Fatigue	• Girth Weld • Gamma plug •	X	X	X	X		X	MT on Gamma plug MT, PAUT, UT, Replica on girth weld	East MSV Outlet Nozzle completed on Unit 1 in 2013
West Turb Gov Valve Terminal	Creep & Creep Fatigue	• Flange Weld	X	X	X	X		X	MT, PAUT, UT, Replica on girth weld	Possible Isolated creep voids In HAZ (Type III)
Unit 2 Hot Reheat Piping										
East Boiler Link	Creep & Creep Fatigue	• Girth Weld • Thermowell • Gamma plug	X	X	X	X		X	MT on Gamma plug and thermowell MT, PAUT, UT, Replica on girth weld	No evidence of creep voids
Upper Y East Leg and Crotch	Creep & Creep & Creep Fatigue	• Upper Y east weld and crotch • Hanger lug – east side • Gamma plug	X	X	X	X		X	MT on Gamma plug MT, PAUT, UT, Replica on girth weld, and Y crotch	No evidence of creep voids
West CSV Outlet	Creep & Creep Fatigue	• Girth Weld	X	X	X	X		X	MT, PAUT, UT, Replica on girth weld	West CSV Outlet Nozzle Weld completed on Unit 1 in 2013 **Thickness data is required**
Unit 2 Cold Reheat Piping										
East Boiler Link	Fatigue	• Girth Weld	X	X		X		X	MT, UT and PAUT on Weld Looking for ID fatigue cracking	No Evidence of Damage
Htr 6 Bleed Steam Nozzle	Fatigue	• Htr 6 Bleed Steam Nozzle Weld	X	X		X		X	MT, UT and PAUT on Weld Looking for ID fatigue cracking	
East Turbine Terminal	Fatigue	• Flange Weld	X	X		X		X	MT, UT and PAUT on Weld Looking for ID fatigue cracking	
Unit 3 Main Steam Piping										
West Boiler	Creep & Creep	• Girth Weld	X	X	X	X		X	MT on Gamma plug	

Sub-component	Issue	Locations for Inspection	NDE Method						NDE Comment	Comments Findings
			MT	UT	Replica	PAUT[2]	RT	Visual		
Link	Fatigue	• Gamma plug							MT, PAUT, UT, Replica on girth weld,	
Upper Y and BSV	Creep & Creep Fatigue	• Boiler Stop Valve outlet • Upper Y West Leg and crotch • Hanger Lugs • Drain & Gamma plug	X	X	X	X		X	MT on Gamma plug, drain and lug MT, PAUT, UT, Replica on girth weld, and Y crotch	
West Main BSV Inlet	Creep & Creep Fatigue	• West Main Stop Valve Inlet • Gamma plug • Drain • Thermowell + Press Tap	X	X	X	X		X	MT on Gamma plug, drain & inst connections MT, PAUT, UT, Replica on girth weld, and Y crotch	
West Boiler Terminal Above Turb deck at flange	Creep & Creep Fatigue	• Flange Weld	X	X	X	X		X	MT, PAUT, UT, Replica on girth weld	
Unit 3 Hot Reheat Piping										
West Boiler Link	Creep & Creep Fatigue	• Girth Weld • Gamma Plug	X	X	X	X		X		
Lower Y Inlet	Creep & Creep Fatigue	• Girth Weld • Hanger lugs • Gamma plug	X	X	X	X		X		
West CSV Inlet	Creep & Creep Fatigue	• Girth Weld • Drain + Press Tap • Gamma plug	X	X	X	X		X		
East Turbine Terminal	Creep & Creep Fatigue	• Flange Weld	X	X	X	X		X		
Unit 3 Cold Reheat Piping										
West Boiler Link	Fatigue	• Girth Weld	X	X		X		X		
East Turb	Fatigue	• Flange Weld	X	X		X		X		

Sub-component	Issue	Locations for Inspection	NDE Method						NDE Comment	Comments Findings
			MT	UT	Replica	PAUT[2]	RT	Visual		
Terminal										
Drain & Inst Connection East Leg	Fatigue	• Drain & Inst connections below turbine, east side	X	X		X		X		
Unit 1 Feedwater Piping										
HP Feedwater Piping	FAC	• P1 BFP disch elbow & expander		X					UT wall thickness on grid	
HP Feedwater Piping	FAC	• HP Flow Element		X					UT wall thickness on grid	
HP Feedwater Piping	FAC Thermal Fatigue	• EC inlet elbow		X		X			UT wall thickness on grid PAUT at weld root and counterbore notch	
SH Attemper-ator	FAC	• West SH Attemp Valve Station		X					UT wall thickness on grid Scan small bore (<= 2")	
BFP Recirc Piping	FAC	• BFP 2 recirc FCV and piping		X					UT wall thickness on grid	
LP Feedwater Piping	FAC	• 2nd elbow before DA		X					UT wall thickness on grid	
Unit 2 Feedwater Piping										
HP Feedwater Piping	FAC	• P1 Disch Elbow		X					UT wall thickness on grid	
HP Feedwater Piping	FAC	• Htr 4 Disch double elbow		X					UT wall thickness on grid	Evidence of FAC
HP Feedwater Piping	FAC	• Htr 5 Disch Tee		X					UT wall thickness on grid	
HP	FAC	• Htr 6 Disch Valve, elbow		X		X			UT wall thickness on grid	

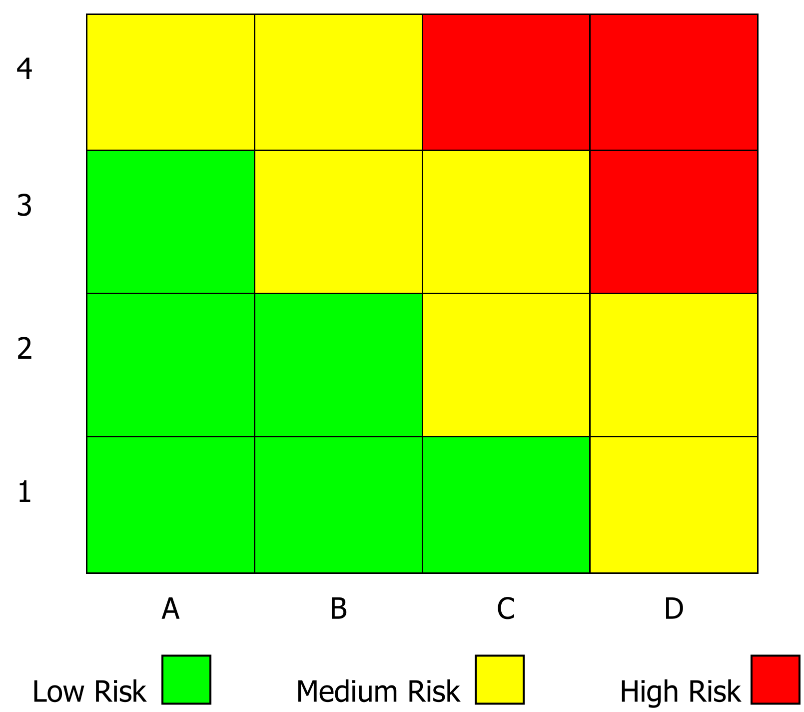
Sub-component	Issue	Locations for Inspection	NDE Method						NDE Comment	Comments Findings
			MT	UT	Replica	PAUT[2]	RT	Visual		
Feedwater Piping	Thermal Fatigue								PAUT at weld root and counterbore notch	
SH Attemper-ator	FAC	East SH Attemp Supply Flow Element + piping and Valve Station		X					UT wall thickness on grid	Possible wall thinning down stream of TV619C
LP Feedwater Piping	FAC	• Elbow and T out of #2 heater		X					UT wall thickness on grid	No evidence of FAC
Unit 3 Feedwater Piping										
HP Feedwater Piping	FAC	• P1 BFP Disch piping, thermowells, and elbows		X					UT wall thickness on grid	
HP Feedwater Piping	FAC	• P2 BFP 45Deg Branch + reducer		X					UT wall thickness on grid	
HP Low Flow Piping	FAC	• Tees to low flow and attempt + reducer		X					UT wall thickness on grid	
HP Low Flow Piping	FAC	• Low flow disch to main run - tee + downstream elbow		X					UT wall thickness on grid	
HP Feedwater Piping	FAC Thermal Fatigue	• Elbow before EC		X		X			UT wall thickness on grid PAUT at weld root and counterbore notch	
LP Feedwater Piping	FAC	• LP Feedwater flow element above Htr 2		X					UT wall thickness on grid	

Appendix B: Risk Models

Technical Risk

The risk assessment model has been developed based on methods proposed by the American Petroleum Institute (API RP 580), in lieu of a model specific to the power utility industry. The 4x4 model below was developed for the Holyrood Thermal Generating Station Condition Assessment Life Extension Study. The consequence of an adverse event is measured in cost terms on the horizontal axis and the likelihood or frequency of the event on the vertical axis.

Technological risk of Failure Analysis Model



<u>Likelihood of Failure Event:</u>

1. Greater than 10 years
2. 5 to 10 years
3. 1 to 5 years
4. Immanent (< 1 year)

<u>Consequence of Failure Event:</u>

A. Minor ($10k-$100k or derating/1 day outage)
B. Significant ($100k-$1m or 2-14 days outage)
C. Serious ($1m-$10m or 15-30 days outage)
D. Major (>$10m or >1 month outage)

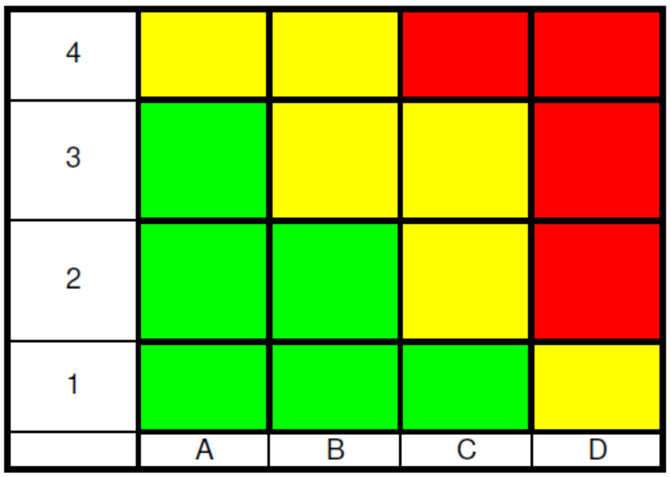
<u>Actions:</u>

- Items that do not apply are not ranked
- Low Risk: Monitor long term (within 5 years)
- Medium Risk: Investigate and monitor short term. Take action where beneficial
- High Risk: Corrective action required short term

Safety Risk Failure Analysis

In addition to the technological risk of failure analysis, a preliminary safety risk of failure analysis was undertaken at NL Hydro's request. Its basic format is based on that of the technological risk assessment model above and is somewhat of a hybrid of the more complex "Real Hazard Index" model used by the US Department of Defence. The modified model is presented below in Table 3-2.

Safety Risk of Failure Analysis Model



Low Risk Medium Risk High Risk

<u>Likelihood of Safety Incident Event:</u>

1. Improbable – so that it can be assumed not to occur
2. Unlikely to occur during life of specific item/process
3. Will occur once during life of specific item/process
4. Likely to occur frequently

<u>Consequence of Safety Incident Event:</u>

A. Minor - will not result in injury, or illness
B. Marginal - may cause minor injury, or illness
C. Critical - may cause severe injury, or illness
D. Catastrophic - may cause death

<u>Actions</u>:

- Items that do not apply are not ranked;
- Low Risk: Monitor, take action where beneficial;
- Medium Risk: Investigate and monitor short term. Take action where beneficial; and
- High Risk: Unacceptable. Corrective action required short term

Appendix C: Creep Life Calculations

Project Title:	Holyrood Condition Assessment Phase 2
Client:	Newfoundland and Labrador Hydro
Title:	Review of Ultrasonic Thickness Measurements for SH-6 Header, Main Steam East Outlet Link, and Hot Reheat East Outlet Link

1.0 INTRODUCTION

1.1 Problem Definition

Newfoundland and Labrador Hydro, a subsidiary of Nalcor Energy, owns and operates the Holyrood Thermal Generation Station (HTGS). The station is equipped with three oil-fired generation units which were originally commissioned in 1969, 1970, and 1979, respectively, at a rated output of 150 MW per unit. The first two units were modified and uprated to 170 MW in 1988 and 1989 respectively, bringing the total generation capacity of the plant to 490 MW.

Nalcor Energy requires that the HTGS operate as currently configured until 2020. Units 1 and 2 will then be decommissioned, and Unit 3 is expected to continue as a synchronous condensing facility until 2041. A thermal generation station, operating continuously between outages for routine repairs and maintenance, has a typical life expectancy of 30 years. The HTGS has only experienced annual CF's in the 30% to 50% range since the plant went into service, because the abundance of hydro-electric power allows for the HTGS to be run at low loads, or not at all, from late spring to late fall each year. Nevertheless, engineering studies are needed to identify components and/or systems requiring remedial measures (maintenance, inspection and/or analysis) for continued reliable operation of the HGTS to 2020.

1.2 Objectives

In 2010, AMEC NSS performed a Level I Condition Assessment of the boilers, high energy piping and major pressure vessels in the HTGS [1]. The objectives of the Level I assessment were to assess the remaining lives of these components and to identify potential degradation mechanisms that could adversely affect remaining life and reliability over the target operating period. Design and historical operating and maintenance data were used as the basis for remaining life assessments.

Nalcor Energy has contracted AMEC NSS to perform a follow-up Level II Condition Assessment [2] to: (i) confirm potential degradation problems identified in the Level I assessment, (ii) validate remaining life predictions from the Level I assessment, (iii) and provide recommendations for either life management or follow-up actions to ensure desired life and performance is achieved.

In support of this Level II Condition Assessment, ultrasonic thickness measurements were obtained for the following components in Unit 2 in 2012:

- West SH Feedwater Attemperator Station, 3” Piping South of Valve
- West SH Feedwater Attemperator Station, South Side Elbow and Adjoining 3” Piping
- West HP Flow Element, 3” Piping Upstream and Downstream of Weld
- #2 Heater Piping and Tee From LP Heater Deck (10” Piping and Tee)
- #2 Heater Piping and Tee From LP Heater Deck 2 (10” PUP Piece)
- #2 Heater Piping and Tee From LP Heater Deck (8” Pipe, Elbow, and End Cap)
- Heater #4 Discharge Double Elbow (10” elbows and connecting piping)
- Cold Reheat East Link @ Level 9 (16” Piping)
- West Main Steam Governor Valve Terminal Flange Weld (10" Piping)
- Hot Reheat East Link @ Level 8 (16” Piping)
- Main Steam East Link @ Level 8 (10” Piping)
- Superheater Front Outlet Header (SH-6)
- Hot Reheat Y East Leg @ Level 8 (16” Piping)

The objectives of this calculation note are to: (i) review the thickness measurements for the hot reheat link, main steam link, and superheater front outlet header in Unit 2; (ii) assess the impact of these measurements on the validity of the creep rupture analyses of these components in the Level I Condition Assessment.

2.0 REVIEW OF WALL THICKNESS MEASUREMENTS

The results for the Hot Reheat East Link, Main Steam East Link, SH-6 header, and Hot Reheat Y East Leg are located on Pages 15, 16, 17, and 18 of the inspection report [3], respectively. Each row of tabulated measurements corresponds to a set of circumferential grid points, and each column corresponds to a set of longitudinal grid points. For each component, the overall minimum and maximum measured wall thicknesses are highlighted in red and green respectively. The minimum measured wall thickness in each row of circumferential grid points is highlighted in yellow.

Table 1 compares the minimum measured wall thicknesses for the Hot Reheat East Link, Main Steam East Link, and SH-6 header from Unit 2 to minimum measured wall thicknesses for the Hot Reheat West Link, Main Steam West Link, and SH-6 header in Unit 1 based on ultrasonic wall thickness measurements by TEAM Inspection Services. The inspection reports for the TEAM measurements contained in Reference 4. The difference between the minimum measured wall thicknesses for corresponding components in Units 1 and 2 is less than 1.5 mm. However, it should be noted that the minimum measured wall thicknesses for the Unit 1 components are based on very limited measurements at one location.

Table 2 compares the minimum and maximum measured wall thickness for the Hot Reheat East Link, Hot Reheat Y East Leg, Main Steam East Link, and SH-6 header in Unit 2 with the specified minimum wall thickness (as per Reference [3]), and pressure-based minimum wall thickness (as per Section I, Paragraph PG-27 of the ASME B&PV Code [5]). The difference between the minimum measured wall thickness and maximum measured wall thickness in each component ranges from 1.75 mm in the SH-6 header to 4.27 and 4.66 mm in the hot reheat and main steam outlet links, respectively. However, the minimum measured wall thickness for each component exceeds the corresponding pressure-based minimum wall thickness and specified minimum wall thickness[4].

3.0 IMPACT ON LEVEL I CREEP RUPTURE ANALYSES

Units 1 and 2 have accumulated 176,787 and 168,122 operating hours, respectively, as of end of February 2012 [9], and are expected to accumulate an additional 48,708 hours5 of operation by end of 2020. The additional operating hours are based on an operating factor of 85% from the start of March 2012 to the end of 2017 and an operating factor of 20% from the start of 2018 to the end of 2020. Therefore, Units 1 and 2 are projected to accumulate 225,495 and 216,830 operating hours, respectively, by end of 2020.

The main steam piping, SH-6 header, and hot reheat piping were the most limiting components in the creep rupture analyses of the Level I Condition Assessments of HTGS Units 1 and 2 [7,8]. The highest LFE[6] values under MCR[7] conditions were predicted for the main steam piping: LFE = 0.32 for every 100,000 hours of operation under original MCR conditions, and LFE = 0.38 for every 100,0000 hours of operation under uprated MCR conditions[8]. Units 1 and 2 were uprated after 54,741 and 62,471 hours of operation under original MCR conditions, respectively. The predicted LFE values at uprate for the main steam piping in Units 1 and 2 were 0.18 and 0.2 respectively. Based on the above data, the LFE values for the main steam piping in Units 1 and 2 would not reach 1.0 until Units 1 and 2 have accumulated ~270,500 and ~273,000 operating hours respectively[9].

The creep rupture analyses of the Level I Condition Assessments of HTGS Units 1 and 2 were based on the specified minimum wall thickness. Since the current minimum measured wall thickness of the Hot Reheat East Link, SH-6 header, Main Steam East Link, and Hot Reheat Y East Leg in Unit 2 exceed the corresponding specified minimum

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[4] The specified minimum wall thickness for the SH-6 header is the as-specified minimum wall thickness. The specified minimum wall thickness for the main steam and hot reheat piping is the specified wall thickness – 12.5% under tolerance.

[5] 8760 x [0.85 x (5+305/365)] + 8760 x 0.20 x 3 = 48,708 hrs

[6] Life Fraction Expended

[7] Maximum Continuous Rating

[8] See creep rupture calculations for piping in “EXCEL spreadsheet AM060_Creep_Without EK_FINAL.xls” [6]. See creep rupture calculations for headers in “AM060_Creep_With EK_FINAL.xls” for headers [6].

[9] (1-0.18)/0.38*100,000+54,741= 270,500 hrs for Unit 1
(1-0.2)/0.38*100,000+62,471 = 273,000 hrs for Unit 2

wall thickness, the creep rupture analyses are not invalidated by the current wall thickness measurements. Therefore, 260,000 operating hours could be taken as a conservative limiting end-of-life for creep rupture of high temperature components in Units 1 and 2, provided there is no active wall thinning in these components.

General or local low temperature corrosion are not expected degradation mechanisms for these high temperature components. However, wall thinning due to high temperature oxidation and spalling of scale off the inner surfaces of the components cannot be ruled out because there are no previous wall thickness measurements to compare against the current measurements. The margins between the minimum measured wall thickness and specified minimum wall thickness range from 0.6 mm for the Hot Reheat East Link to 4.2 mm for the SH-6 header. It is recommended that wall thickness measurements of the high temperature headers and piping be repeated in 3 years time to assess potential wall loss rates, and implications for remaining life. Wall thickness measurement should consist of at least five locations to minimize the impact of measurement error and irregularities in wall thickness.

4.0 REFERENCES

[1] T. Mahmood, "HTGS Condition Assessment and Life Extension Study", AMEC NSS Report AM060/RP/001, May 13, 2010.

[2] "Condition Assessment and Life Extension Study, Phase II, Holyrood Thermal Generating Station", Nalcor Energy RFP 2012-51007, May 1, 2012.

[3] "Ultrasonic Inspection Report – Holyrood Condition Assessment – Unit 2 Piping Components", Acuren Report No. UT-SS1016-012, Oct. 16, 2012.

[4] T. Ogundimu, "Holyrood Thermal Generating Station Condition Assessment and Life Extension Study Phase 2 - 2013 NDE Reports and Report References, AMEC NSS Record AM132/RE/043, 15 August 2013

[5] ASME Boiler and Pressure Vessel Code, 1965 edition.

[6] "Electronic Records and Analysis Files (EXCEL Spreadsheets, QA Records, References, and Calculation Notes)", AM060/CD/001, April 28, 2010.

[7] R. Yee, "Creep Rupture Assessments of High-Temperature Headers in Holyrood Units 1&2", AM060/CN/006, April 28, 2010.

[8] R. Yee, "Creep Rupture Assessments of High-Temperature Piping in Holyrood Units 1&2", AM060/CN/007, April 28, 2010.

[9] Newfoundland and Labrador Hydro, Request for Proposals, "Condition Assessment and Life Extension Study, Phase II – Holyrood Thermal Generating Station", RFP 2012-51007, May 2012.

Table 1: Minimum measured wall thicknesses (mm) for hot reheat outlet link, main steam outlet link, and SH-6 header in Units 1 and 2.

Hot Reheat Outlet		Main Steam Outlet		SH-6 Header	
U2 East Link	U1 West Link	U2 East Link	U1 West Link	U2	U1
16.69	**18.21**	**35.25♣**	**36.12***	**75.62**	**75.3**

* Minimum measured wall thickness at Unit 1's east main steam stop valve outlet = 36.12 mm.
Minimum measured wall thickness at Unit 1's east main steam governor valve termination = 34.54 mm.
See Appendix B for inspection report.

♣ Minimum measured wall thickness at Unit 2's west main steam governor valve termination = 35.9 mm.
See Page 17 of inspection report.

Table 2: Comparison of measured wall thickness (minimum and maximum), specified minimum wall thickness, and pressure-based minimum wall thickness for hot reheat east outlet link, hot reheat Y east leg, main steam east outlet link, and SH-6 header in Unit 2.

	Hot Reheat Outlet Link	Hot Reheat Y East Leg	Main Steam Outlet Link	SH-6 Superheater Front Outlet Header
Material	SA-335 P22	SA-335 P22	SA-335 P22	SA-387 Grade D
Design Temperature[1,2] T_{design} (^{o}F)	1005	1005	1005	1035
Code Allowable Stress[7] S (psi)	7600	7600	7600	6400
Design Pressure[3,4] P_{design} (psi)	586	586	1980	2205
Nominal Outer Diameter [5,6] D (in)	16	16	10.75	18
weld factor [8] w	1	1	1	0.9
ligament efficiency[9] e	1	1	1	0.893
Overal Efficiency Factor[8] E = min (w, e)	1	1	1	0.893
Temperature Factor[10] y	0.7	0.7	0.7	0.7
Stability Factor[11] C	0	0	0	0
pressure-based minimum wall thickness[12] $t_{min,p}$ (in)	0.585	0.585	1.184	2.734
pressure-based minimum wall thickness[12] $t_{min,p}$ (mm)	14.865	14.865	30.082	69.443
specified minimum wall thickness[13,14] $t_{min,specified}$ (mm)	16.078	16.078	32.487	71.425
measured minimum wall thickness[15] $t_{min,measured}$ (mm)	16.69	18.26	35.25	75.62
measured maximum wall thickness[15] $t_{min,measured}$ (mm)	20.96	20.60	39.91	77.37

[1] Design temperature for HRH outlet and main steam outlet from Table 3, Part IV of AM060/RP/001 [2]

[2] Design temperature for SH-6 header from Table 2, Part I of AM060/RP/001 [2]

[3] Design pressure for HRH outlet and main steam outlet from Table 3, Part IV of AM060/RP/001 [2]

[4] Design pressure for SH-6 header rom Table 2, Part I of AM060/RP/001 [2]

[5] Nominal outer diameter for HRH outlet and main steam outlet from Table 5, Part IV of AM060/RP/001 [2]

[6] Nominal outer diameter for SH-6 header from Table 1, Part I of AM060/RP/001 [2]

[7] From Table PG-23.1, Appendix A-24, Section I, ASME B&PV Code (1965)

[8] As per Note 1, PG-27, Section I, ASME B&PV Code (1965)

[9] Ligament efficiency for SH-6 header from Table 4, Part 1 of AM060/RP/001 [2]

[10] As per Note 6, PG-27, Section I, ASME B&PV Code (1965)

[11] As per Note 3, PG-27, Section I, ASME B&PV Code (1965)

[12] $t_{min,\ pressure}$ = PD/(2SE+2yP) + C   PG-27b, Section I, ASME B&PV Code (1965)

[13] For HH and main steam piping, $t_{min,\ specified}$ = 0.875 x specified wall thickness from Table 4, Part IV of AM060/RP/001 [2].

[14] For SH-6 header, $t_{min,specified}$ = specified minimum wall thickness from Table 1, Part I of AM060/RP/001 [2]

[15] From ultrasonic thickness measurements

Appendix D: Unit 2 Flow Accelerated Corrosion Report

FLOW ACCELERATED CORROSION ANALYSIS REPORT		
Client: Holyrood TGS		
Unit:	**Systems:**	**Date:**
2	Condensate, Feedwater (FW)	January 30, 2013
Operating Years:		**AMEC NSS File Number:**
Total:	41 (168,122 operating hours as of Feb. 2012 [5])	AM132/RP/004 R02
Since Last Inspection:	N/A	
Inspection Method:	**Inspection Procedure/Technique:**	**Inspection Date:**
☒ Ultrasonic (U/T)	AGI UT 03 Technique 01 [1]	October 2012
☐ Pulse Eddy Current (Incotest)		
☐ Radiography		
☒ X-Ray Fluorescence (Material Testing)	MEC-4026 [2]	

SCOPE (Locations and Component Summary):

The entire planned inspection scope [3] of 18 locations across Holyrood TGS Stage I and Stage II could not be completed during the 2012 outage window. Wall thickness measurements and material testing were performed at the following four (4) locations on Unit 2:

- **Site No. 1-4:** Location 1-4 from Reference [3] is the HP FW Piping to Attemperator: East Valve Station on Unit 1; however this inspection site was redirected to the HP FW Piping to Attemperator: West Valve Station on Unit 2, which has a similar configuration.
- **Site No. 2-2:** BFP Discharge: Double Elbow at HP FW Heater 4 Exit
- **Site No. 2-5:** HP FW Piping to Attemperator: Flow Element FE 5568
- **Site No. 2-6:** LP FW Piping (Condensate): Heater 2 Exit, Elbow and Tee

Details of the inspected locations and component geometries are provided in Table 1. The inspected locations are marked on the Isometric Sketches and/or General Arrangement Drawings (GAD's) and/or photographs included in Appendix B.

RESULTS AND COMMENTS:

The following results were obtained by using the EPRI Band Method wall thinning assessment methodology, as documented in AMEC NSS FAC procedures [4]. The results are summarized in Table 1. The re-inspection times calculated in Table 1 are based on the minimum required wall thicknesses reported in the planned inspection scope [3]; conversion between operating years and operating hours was performed based on the historical average of 4,000 operating hours per year (Unit 2).

The inspection locations, critical dimensions, calculated wear rates and recommended next inspection dates are listed in Table 1. The wall thickness profiles are compiled in Appendix A for locations with re-inspection times less than 40,000 operating hours. As well, the inspection report is reproduced in Appendix C.

Locations Below Code Minimum Wall:

- None

Material Testing:

- Industry experience indicates that trace amounts of chromium, copper, and molybdenum alloy will reduce or eliminate FAC. Thus, the Positive Material Identification By Portable X-ray Tube (XRF) X-ray Florescence Analyser was implemented at each inspection location, and the results were reviewed as part of this assessment.
- Unfortunately, the material testing results were inconsistent and therefore considered unreliable. As such, the material testing results were not used in this assessment.

Recommendations:

- **Site No. 1-4:** HP FW Piping to Attemperator: West Valve Station (Unit 2) – Wear rate analysis was performed for the four 3" components that were inspected using a grid layout; all locations are deemed fit for service for more than 10 years (40,000 operating hours). Several small bore components (pipe sections, tees, and reducers 2" NPS and less) were scanned, and the lowest readings were reported. All components show sufficient margin above the minimum required wall thickness (ASME pressure based wall thickness).
    - Note that there is a noticeable difference in margin between the upstream and downstream pipes of valve 2TV619C; this observation assumes that both components are original components. Since the valve stub piping material is noted as Cr-Mo (e.g. in UT survey records), it is unlikely that the wear is caused by FAC. Wall thinning is likely due to erosion caused by hydrodynamic effects introduced by the valve, or a due to valve passing. Given the sufficient margin on wall thickness, there is no near term concern from an integrity standpoint; however the valve should be considered for follow up investigation and the stub piping should be rescanned in 3 years (12,000 hours) to estimate a wall loss rate. Material testing is also recommended to confirm presence of chromium and molybdenum alloys.
    - Note also that the lower loop bypass was not inspected; if this line is only used intermittently then advanced damage due to FAC is very unlikely.
- **Site No. 2-2:** BFP Discharge: Double Elbow at HP FW Heater 4 Exit – Wear rate analysis was performed for all components. The pipe downstream of the double elbows shows signs of FAC related wall thinning (see Appendix A). The remaining life is conservatively estimated to be 7 years (28,000 operating hours) due to high margin on minimum wall thickness. All other components are fit for service for more than 10 years. All readings are above 87.5% of nominal wall thickness (i.e. within manufacturing tolerance).
- **Site No. 2-5:** HP FW Piping to Attemperator: Flow Element FE 5568 – The downstream portion of the flow element and the downstream piping were inspected with a grid layout (1/2"). No evidence of FAC was observed, and both components are fit for service for more than 10 years (40,000 operating hours). Note that the upstream portion was not inspected; FAC related damage has been observed upstream of flow elements, thus future inspections should include this region.
- **Site No. 2-6:** LP FW Piping (Condensate): Heater 2 Exit, Elbow and Tee – Several 8" and 10" components downstream of the Heater 2 exit were inspected, and all components were found to be fit for service for more than 10 years (40,000 operating hours). All readings are above 87.5% of nominal wall thickness (i.e. within manufacturing tolerance) and no evidence of FAC damage is observed.

In summary, 4 of the 18 recommended locations were inspected, and one location showed indications of advanced FAC wall thinning. Due to the relatively small number of sites inspected, it would be premature to comment on the condition of FAC in the FW system at Holyrood TGS. Continued inspections are recommended (i.e. continuation of the sites defined in the inspection scope [3]); based on the present results the FW system locations should rank higher in priority over the condensate system locations.

As previously mentioned, the material testing performed in the present outage was not considered reliable; however, industry experience indicates portable material analyzers can work reliably with the proper precautions. It is recommended that the testing methods be reviewed and resolved for future inspection campaigns.

Based on projected future operation (30 to 75% annual capacity factor to 2017, and reduced/limited operation to 2020), locations with re-inspection intervals more than 10 years (40,000 operating hours) will not need to be revisited.

References:

1. Acuren Procedure AGI UT 03 Technique 01 Revision 2, February 2012.
2. Acuren Procedure MEC-4026 Positive Material Identification By Portable X-ray Tube (XRF) X-ray Florescence Analyser, January 29, 2008.
3. AM132/RP/001 R01 – "Holyrood Thermal Generating Station Flow Accelerated Corrosion (FAC) Feedwater and Condensate Piping Inspection Scope for Stage I & II 2012 Outages", September 28, 2012.
4. NSS00/PR/034 R01 – "Analysis Process for Flow Accelerated Corrosion based on UT Inspection Results", March 9, 2012.
5. Newfoundland and Labrador Hydro, Request for Proposals, "Condition Assessment and Life Extension Study, Phase II – Holyrood Thermal Generating Station", RFP 2012-51007, May 2012.

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Table 1 - Summary Table - Holyrood TGS Unit 2 Flow Accelerated Corrosion - October 2012 Inspection Analysis

Base Data						Inspection Results: Fabricated (")		Inspection Results: Measured					Inspection Status		
Location Description	Site No.	Component	NPS (Inch)	70% of Nominal Thickness[3] (Inch)	ASME Minimum Wall (Inch)	Nominal Wall[5] (Inch)	Minimum Wall[6] (Inch)	t_{min} (Inch)	Band [2] t_{max} (Inch)	Maximum Wear[4] (Inch)	Band Wear rate (Inch/yr)[1]	Margin to Minimum Req'd Wall Thickness (Inch)	Potential Signs of FAC	Re-inspection time[7,9]	Comments
HP FW Piping to Attemperator: West Valve Station	Site No. 1-4: Location 1-4 from Reference [3] is the HP FW Piping to Attemperator: East Valve Station on Unit 1; however this inspection site was redirected to a similar configuration on Unit 2	Pipe U/S Elbow	3	0.307	0.319	0.438	-	0.413	0.475	0.062	0.002	0.094	Minor	> 40,000 hours	
		Elbow U/S Valve 2TV619C	3	0.307	0.319	0.438	-	0.409	0.513	0.104	0.003	0.090	Moderate	> 40,000 hours	
		Pipe D/S Elbow	3	0.307	0.319	0.438	-	0.409	0.455	0.045	0.001	0.090	Minor	> 40,000 hours	
		3x2" Reducer	3x2	0.307	0.319	0.438	-	0.608	N/A	N/A	N/A	0.289	N/A	Low wear	
		Pipe U/S Valve 2TV619C	2	0.241	0.217	0.344	-	0.428	N/A	N/A	N/A	0.211	N/A	Low wear	
		Pipe D/S Valve 2TV619C	2	0.241	0.217	0.344	-	0.338	N/A	N/A	N/A	0.121	N/A	12,000 hours	Note that wear is substantially greater downstream of TV619C
		3x2" Reducer	3x2	0.307	0.319	0.438	-	0.602	N/A	N/A	N/A	0.283	N/A	Low wear	
		Pipe D/S Valve 2TV619C (Grid)	3	0.307	0.319	0.438	-	0.426	0.477	0.051	0.001	0.107	Minor	> 40,000 hours	
		Pipe D/S Valve 2TV619C (Scan)	3	0.307	0.319	0.438	-	0.418	N/A	N/A	N/A	0.099	N/A	Low wear	Component scanned due to pipe support
		3x2" Reducer	3x2	0.307	0.319	0.438	-	0.418	N/A	N/A	N/A	0.099	N/A	Low wear	
		Tee	2	0.241	0.217	0.344	-	0.591	N/A	N/A	N/A	0.374	N/A	Low wear	
		Pipe U/S NRV	2	0.241	0.217	0.344	-	0.336	N/A	N/A	N/A	0.119	N/A	Low wear	
		Pipe D/S NRV	2	0.241	0.217	0.344	-	0.319	N/A	N/A	N/A	0.102	N/A	Low wear	1.5mm depth pit immediately downstream. South end obstructed by pipe support at bottom.
		2x1" Reducer	2x1	0.241	0.217	0.344	-	0.606	N/A	N/A	N/A	0.389	N/A	Low wear	
		Pipe U/S Valve 2TV619A	1	0.175	0.12	0.25	-	0.199	N/A	N/A	N/A	0.079	N/A	Low wear	
		Pipe D/S Valve 2TV619A	1	0.175	0.12	0.25	-	0.205	N/A	N/A	N/A	0.085	N/A	Low wear	
		2x1" Reducer	2x1	0.241	0.217	0.344	-	0.559	N/A	N/A	N/A	0.342	N/A	Low wear	
		Pipe U/S Tee	2	0.241	0.217	0.344	-	0.327	N/A	N/A	N/A	0.110	N/A	Low wear	
		Tee	2	0.241	0.217	0.344	-	0.642	N/A	N/A	N/A	0.425	N/A	Low wear	
		Pipe D/S Tee	2	0.241	0.217	0.344	-	0.331	N/A	N/A	N/A	0.114	N/A	Low wear	
		Pipe D/S NRV	2	0.241	0.217	0.344	-	0.330	N/A	N/A	N/A	0.113	N/A	Low wear	

Base Data						Inspection Results							Inspection Status		
						Fabricated (")		Measured							
Location Description	Site No.	Component	NPS (Inch)	70% of Nominal Thickness[3] (Inch)	ASME Minimum Wall (Inch)	Nominal Wall[5] (Inch)	Minimum Wall[6] (Inch)	t_{min} (Inch)	Band[2] t_{max} (Inch)	Maximum Wear[4] (Inch)	Band Wear rate (Inch/yr)[1]	Margin to Minimum Req'd Wall Thickness (Inch)	Potential Signs of FAC	Re-inspection time[7,9]	Comments
BFP Discharge: Double Elbow at HP FW Heater 4 Exit	Site No. 2-2	1st Elbow	10	-	0.98	1.125	-	1.125	1.279	0.154	0.004	0.145	Moderate	> 40,000 hours	
		Pipe	10	-	0.98	1.125	-	1.093	1.174	0.081	0.002	0.113	Minor	> 40,000 hours	
		2nd Elbow	10	-	0.98	1.125	-	1.083	1.286	0.203	0.005	0.103	Significant	> 40,000 hours	
		Pipe	10	-	0.98	1.125	-	1.038	1.199	0.161	0.004	0.058	Moderate	28,000 hours	See Appendix A for wall thickness profile.
HP FW Piping to Attemperator: Flow Element FE 5568	Site No. 2-5	Flow Element FE5568	3	-	0.319	-	-	0.606	0.646	0.040	0.001	0.287	Minor	> 40,000 hours	Note that the upstream end of the flow element was not inspected. Also, the pipe size was not available for the stub pipes, thus they could not be assessed; FAC is not anticipated in these components due to lack of flow.
		Pipe D/S FE5568	3	0.307	0.319	0.438	-	0.433	0.506	0.072	0.002	0.114	Minor	> 40,000 hours	
LP FW Piping (Condensate): Heater 2 Exit, Elbow and Tee	Site No. 2-6	Pipe U/S Tee	8	0.225	Note 8	0.322	-	0.317	0.337	0.020	<0.001	0.092	Minor	> 40,000 hours	Only 2 bands of data
		Tee	8	0.225		0.322	-	0.307	0.430	0.124	0.003	0.081	Moderate	> 40,000 hours	
		Elbow	8	0.225		0.322	-	0.325	0.378	0.053	0.001	0.100	Minor	> 40,000 hours	
		Pipe D/S Elbow	8	0.225		0.322	-	0.317	0.333	0.017	<0.001	0.091	Minor	> 40,000 hours	Small section, 1 band of data
		8x10 Reducer (Small End)	8	0.225		0.322	-	0.398	0.453	0.055	0.001	0.172	Minor	> 40,000 hours	
		8x10 Reducer (Large End)	10	0.256		0.365	-	0.359	0.423	0.064	0.002	0.103	Minor	> 40,000 hours	
		Pipe U/S Tee	10	0.256		0.365	-	0.359	0.370	0.011	<0.001	0.104	Minor	> 40,000 hours	
		Tee	10	0.256		0.365	-	0.396	0.562	0.167	0.004	0.140	Moderate	> 40,000 hours	
		Tee Branch	10	0.956		1.365	-	0.352	0.385	0.033	0.001	0.096	Minor	> 40,000 hours	
		Pipe D/S Tee	10	0.256		0.365	-	0.358	0.367	0.009	<0.001	0.102	Minor	> 40,000 hours	

1 Based on 41 years of service (in-service as of 1971).
2 Band refers to the circumferential band of which t_{min} is located.
3 70% of nominal wall is used to avoid possible leakage or burst in situations where the ASME min wall is very low.
4 This column represents band wear.
5 This column represents nominal wall thickness corresponding to the pipe schedule, or assumed pipe schedule if not directly available.
6 This column represents minimum wall thickness corresponding to the piping and insulation schedule.
7 The re-inspection time is based on margin above the required minimum wall thickness, except for repaired or previously repaired locations.
8 The design pressure for the condensate system was not provided.
9 Analysis was performed based on years of service and re-inspection time was converted to hours using lifetime average operating hours of 4,000 hours per year

Significant	>0.200" between max and min
Moderate	0.100" - 0.200" between max and min
Minor	0.000" - 0.100" between max and min

Inspection Dates

Current	Oct. 2012
Previous	N/A
Delta (Years)	N/A

The FAC report and referenced NDE Reports are available in the project reference binder [R-9].

Appendix E: Hanger Inspection Summary

Project Title:	Holyrood Condition Assessment Phase 2
Client:	AMEC Power and Process Newfoundland
Title:	HTGS Hanger Inspection Summary

1.0 INTRODUCTION

Newfoundland and Labrador Hydro (HYDRO), a subsidiary of Nalcor Energy, owns and operates the Holyrood Thermal Generation Station (HTGS). The station is equipped with three oil-fired residual fuel oil-fired units having a total combined output of 500 MW (nominally 150 to 175 MW units) [R-1].

Nalcor Energy requires that the HTGS operate as currently configured until 2020. Units 1 and 2 will then be decommissioned, and Unit 3 is expected to continue as a synchronous condensing facility until 2041. The HTGS has only experienced annual capacity factors in the 30% to 50% range since the plant went into service, because the abundance of hydro-electric power allows for the HTGS to be run at low loads, or not at all, from late spring to late fall each year. Inspection and subsequent assessment are needed to identify components and/or systems requiring remedial measures (maintenance, inspection and/or analysis) for continued reliable operation of the HGTS to 2020 [R-1].

2.0 OBJECTIVES

Monitoring of high energy steam piping hangers is an important ageing management activity as a malfunctioning support system or abnormal operating events can lead to load redistribution, stress concentrations, and non-drainable areas (sagging) where condensate can collect. Stress concentrations can cause or accelerate creep and fatigue damage in the piping. Condensate can cause corrosion and significant operating transients on start-up if the operators are not aware of the issue.

In 2010, AMEC NSS performed a Level I Condition Assessment of the boilers, high energy piping and major pressure vessels in the HTGS [1]. The objectives of the Level I assessment were to assess the remaining lives of these components and to identify potential degradation mechanisms that could adversely affect remaining life and reliability over the target operating period. Design and historical operating and maintenance data were used as the basis for remaining life assessments. A preliminary assessment of pipe hanger condition was conducted. No major damage was found during walk-downs and station personnel had confirmed that there had been no water hammer or pressure transient incident in the last twenty years [1].

Nalcor Energy has contracted AMEC in 2012 to perform a follow-up Level II Condition Assessment to: (i) confirm potential degradation problems identified in the Level I assessment, (ii) validate remaining life predictions from the Level I assessment, (iii) and provide recommendations for either life management or follow-up actions to ensure desired life and performance is achieved [R-1]. The focus for 2012 was the boiler and high-energy piping, including pipe hangers located in the Main Steam, Hot Reheat, and Cold Reheat piping systems.

The pipe hangers and supports were inspected in the Main Steam (MS), Cold Reheat (CR) and Hot Reheat (HR) systems. The objectives of the inspection were to: (i) assess the configuration of the pipe hangers versus the original design; (ii) assess the pipe hanger load distribution; (iii) assess pipe slope and evidence of abnormal operating events; (iv) document hanger condition and mechanical fitness; (v) provide recommendations for changes/repairs of the pipe hanger systems [R-4].

The scope of work for 2013 focused on specific potentially life limiting issues based on the Unit 2 Phase 2 inspections last year and concerns over the Unit 1 turbine trip event in January 2013.

Hanger inspections included completion of the hot walk-downs on Unit 3 and investigation of specific hanger performance issues identified in the 2012 work program [R-2].

Visual inspections of the MS, CR and HR pipe hangers on Unit 1 were conducted to check for possible damage due to the turbine load rejection event [R-2].

This report summarizes the results of the inspections. Recommendations are identified in Section 8.0. For further details on the inspections, reference should be made to the full report in the reference binder.

3.0 METHODOLOGY

The methodology consisted of visual inspection during the hot and cold condition for Unit 1, 2 and 3. Further details on the methodology and the results are provided in the inspection plan for high energy piping supports, [R-4], contained in the inspection reference binder.

4.0 ASSESSMENT OF PRESENT CONFIGURATION VS DESIGN

The steam piping systems consisting of MS, CR and HR in Unit 1&2 were originally designed to be fully floating, consisting of constant load support hangers with no snubbers.

For Unit 3 the steam piping systems was originally designed with a partially floating support system with rigid rod hangers at the lower Y connections.

For Unit 1 and 2, the constant load support hangers were supplied by Aiton & Co. Ltd., and for Unit 3 they were supplied by Carpenter & Paterson Ltd., up to the stop valves.

Constant load support hangers are used for critical piping systems such as high energy piping, where there will be large vertical movements due to thermal expansion [R-5]. In addition, the locations where it is necessary to avoid any transfer of stress from support to support or onto critical terminal points or connecting equipment [R-5].

Variable spring hangers are used in circumstances where constant load support hangers are not required, such as pipe lines subjected to moderate vertical thermal movements and maximum load variation within 25% [R-6].

On the Main Steam system for Units 1&2, the inspections found two variable spring hangers installed instead of two constant load support hangers at MS8/1 and MS8/2 location [R-7]. There are no records indicating the time or reason for the change. For the Hot Reheat system on Units 1&2, there are variable load spring stanchions installed at HR15 and HR17, instead of constant load pipe hangers, trapeze type [R-8]. A drawing prepared by Canadian General Electric Company Limited, shows variable load spring stanchions [R-9].

During the cold walk-downs for Unit 1&2, a couple of discrepancies between the isometric drawings for the Main Steam system and Cold Reheat system with respect to the hanger locations for MS14, MS16, CR2 (Unit 2) and CR6 (Unit 2) were identified. Recommendations for follow-up are provided in Section 8.0.

The boiler stop valve in the main steam line was replaced on Unit 2 in 2008. The Main Steam piping supports were analyzed in the "as found" condition with the variable spring hangers at the MS8/1 and MS8/2 location. A second model was created and modified to reflect the new valve weight and was re-analyzed to assess compliance with the ASME Power Piping Code, B31.1 [R-12].

A review of the stress analysis report was performed by subject matter experts, based on the following criteria:

(i) Completeness of the present analysis relative to ASME B31.1 requirements;

(ii) Acceptability of load distribution before the valve was replaced and after the valve replacement;

(iii) Assess the changes in stress from the original analysis with the one when the stop valve was replaced to determine where the results impact the inspection location selection.

The review concluded the analyses were acceptable. There are several findings (see below) related to the completeness of the analyses. Since the stresses are low, approximately 30% margin on allowable, the findings are not considered significant to invalidate the analysis.

To apply the "as-found" analysis to Unit 1, further review of the Unit 1 main steam field configuration is required. Based on cold and hot walk-downs performed in 2012 and 2013, the piping and hanger configuration between Unit 1 and 2 is similar. Any minor differences between the two units will be covered by the margin in the "as-found" analysis.

The findings from the review are:

- The "reconciliation" of the 2007 ASME code used in the analysis relative to the code of construction (1967) was not documented in the report. Only the allowable stress and modulus of elasticity changed. The equations are not the same between the 1967 and the 2007 ASME B31.1 codes. The thermal coefficient could also be different between the code years and this will affect the thermal analysis results.

- In the analysis, it is not clear how the reduced loading was implemented on the variable spring hanger, MS 8/1 and MS 8/1, where the load was reduced by 400 lbs in order to reduce the reaction loads at the nozzles.
- The supports displacements including cold springing are unknown and could not be included in the report. This is necessary in order to make certain the constant load supports settings are within the range and the variable springs are also within the allowable range. The analysis results could be different depending on the actual displacements.
- The main steam valve was modeled as a rigid element. However, the model concept could affect the forces and moments the valve would transfer to the turbine nozzles.

5.0 ASSESSMENT OF LOAD DISTRIBUTION

The majority of the pipe hangers for the MS, HR and CR systems are operating within the allowable travel range and are taking load during the cold and hot walk-downs.

Constant load supports with springs that are topped out or near topped out condition are: HR6/1 (Unit 1 and 2), HR7/1 (Unit 1 and 2), HR8/1 (Unit 1), HR8/2 (Unit 1 and 2), HR12 (Unit 1), CR23 (Unit 2), HR6/2 (Unit 2), HR7 (Unit 3), MS6/1 (Unit 3), MS6/2 (Unit 3) and HR13 (Unit 3).

The following constant load supports with springs that are bottomed out are: MS8 (Unit 3), CR9 (Unit 3), HR8 (Unit 3) and HR14 (Unit 3).

For the Hot Reheat system in Unit 1 and 2, it appears that a number of the trapeze type constant load hangers, HR6/1, HR6/2, HR7/1, HR7/2, HR8/1 and HR8/2 have unbalanced loading. This can result in one constant load spring can taking more load than the other. This causes the trapeze to twist and the rods to be misaligned.

For the following constant load supports, it appears that the readings between cold and hot load did not change (ex. CR14 (Unit 1), HR6/1 (Unit 2), HR7/1 (Unit 1), HR8/1 (Unit 1), HR8/2 (Unit 1 and 2), MS10 (Unit 1 and 2), MS8/1 (Unit 1), MS16 (Unit 1), MS6/1 (Unit 3), MS6/2 (Unit 3), MS8 (Unit 3), CR9 (Unit 3), HR7 (Unit 3), HR8 (Unit 3), HR13 (Unit 3) and HR14 (Unit 3)).

According to the analysis for the Main Steam system on Unit 2, the constant load hanger, MS10, should be moving between the cold load and hot load set points and exhibit the anticipated amount of travel. Based on review of the results, the constant load hanger, MS10, did not exhibit any movement between the cold load and hot load.

Based on a review of the results from the cold walk-down for Unit 1 and hot walk-down in Unit 2 in 2013, the hanger readings did not change significantly from the readings taken during the cold and hot walk-downs from last year.

The piping loads and hanger indicators may change position after a number of years of operation due to thermal cycling and creep deformation.

Topped out hangers indicate a load redistribution in the piping system.

Bottomed out hangers indicate a localized overloading.

Monitoring of hanger readings in the hot and cold condition is required to confirm if the constant load hanger is either topped, bottomed or has no movement before any adjustments are made.

Unit operations should be reviewed to determine whether system transients are contributing to the hanger problems.

A piping analysis may be required to direct pipe hanger adjustments. For trapeze type hangers, the load should be balanced evenly by the constant load springs on each side of the pipe.

6.0 HANGER CONDITION

The majority of pipe hangers were accessible during the cold and hot walk-downs, and the hangers that were not accessible are noted in the observations column of the hanger record sheet. Also, the readings of the cold load and hot load settings were taken mostly from below the pipe hanger. Due to the angle and distance of viewing the readings may not be precise.

Based on the findings, there were no broken parts of the hanger assemblies identified during the cold and hot walk-downs that would immediately impair the pipe hanger's function. However, the findings identified below could degrade the performance of the pipe hanger and piping if they are not corrected or monitored.

The following main findings along with representative photographs were identified during the cold and hot walk-downs related to the mechanical condition of the hanger assemblies:

- Missing lock-nuts on turnbuckle and load coupling;
- Missing or loose nuts on clamp assembly, turnbuckle and rod coupling;
- External corrosion of constant load support casing, mechanical mechanism and debris build-up in spring can;
- Twisted angle iron for structural support of pipe hanger assembly;
- Deformed beam support for trapeze type hanger;
- Inadequate clearance between hanger rod and floor grating;
- Inadequate engagement of threads for hanger rods and bolts;
- Misaligned rods and twisted clamp assembly.

During the cold and hot walk-downs it was noticed that a couple of the nuts on accessible clamps, such as MS9 on Unit 2, were loose. The nuts on the pipe hangers should be tightened to prevent them from becoming loose and backing off due to operation of the system.

In addition, the base plate and columns for pipe supports, HR15 and HR17, on Unit 1 & 2 were inspected and the findings were documented for follow-up [R-13].

The visual inspections results for the pipe supports, HR15 and HR17, on Unit 1 found external corrosion of the base plate and column. In addition, concrete degradation was identified surrounding the base plate. The NDE examinations for the base plate and column did not find any additional indications from the visual inspection.

The same location on Unit 2 was inspected and there was less concrete degradation surrounding the base plate compared to Unit 1. The concrete degradation identified on Unit 1 could be a result of past system upsets including the recent turbine event.

Corrective action is required on Unit 1 to repair the concrete, install missing cinch anchors and monitor the condition of the pipe support, base plate and column for corrosion [R-13].

Based on the cold walk-down of the other pipe hangers, excluding HR15 and HR17, in Unit 1, there was no damage identified that can be attributed to the vibration event.

7.0 PIPE CONDITION

From the cold and hot walk-downs, there were no findings related to sagging of pipe between the supports. The insulation on the piping made it difficult to assess the slope for each horizontal pipe run. However, in general the piping layout and pipe slope was consistent with the piping isometric drawings. It was noticed that there were signs of possible pipe distortion or upset on the Hot Reheat system in Unit 1 and 2, resulting in misalignment of the trapeze type hangers on the 4^{th} floor.

During the hot and cold hanger walk-downs for Unit 1, 2 and 3, there were a couple findings where the hanger rod is in contact with the insulation of another pipe during the cold or hot load (MS2/A (Unit 2), CR2 (Unit 2), HR6/1 (Unit 2), MS R1 (Unit 3)). Since there is no damage to either the pipe hanger or the pipe insulation there is no action required.

For the trapeze support for MS15 on Unit 2, it was identified that the hanger is in contact with the insulation of a nearby valve. This area should be monitored to ensure the valve body is not damaged.

During the cold and hot walk-downs for Unit 3, it was identified that the rigid pipe hanger in the Cold Reheat system, CR R1, has damaged the insulation of the surrounding Main Steam and Hot Reheat lines. It is recommended that the piping surfaces in contact with the rigid pipe hanger, CR R1, are checked for any damage.

8.0 SUMMARY

The hanger inspections assessment concluded that the support systems on the high energy piping at Holyrood TGS are functioning reasonably well, and that no immediate corrective action is required. The overall recommendations are:

- Implement a piping management program to track pipe hanger performance, and guide pipe hanger repairs, piping inspections and to address minor findings;

- Monitor the pipe hangers that are in the topped and bottomed out condition or showing no movement from the cold load setting to the hot load setting. The priority for inspection should be the constant load hangers in the Main Steam and Hot Reheat systems in Unit 3;

- Conditions where multiple pipe hangers in a system are either topped or bottomed out should be considered for analysis to determine impact on the system piping stresses and load distribution on the other pipe hangers. In addition, manufacturer specifications for the pipe hanger should be consulted;

- The hot reheat pipe supports, HR15 and HR17, on Units 1 and 2 did not conform to the supplied drawing, [R-8], in 2012. The drawing, [R-8], indicated a constant load hanger was to be installed at both locations instead of variable load spring stanchion supports. Based on a site visit in 2013, another drawing was obtained that was prepared by Canadian General Electric Company Limited, that showed variable load spring stanchion supports;

- Based on a review of the results from the cold walk-down for Unit 1 and hot walk-down for Unit 2 in 2013, the hanger readings for MS10 did not change significantly from the readings taken during the cold and hot walk-downs from last year. It is recommended to continue to monitor MS10 on Unit 1 and 2, as part of a piping management program;

- The application of the Unit 2 Main Steam piping "as-found" analysis to the Unit 1 Main Steam pipe support system as a means of confirming code compliance with the MS8 modification can be supported since the piping and hanger configuration between Unit 1 and 2 is similar. Any minor differences between the two units will be covered by the margin in the "as-found" analysis.

- Review and correct minor mechanical issues for the pipe hangers;

- Correct skewed trapeze hangers to balance load distribution between hangers;

- Plan to perform repairs on the concrete surrounding the base plates for HR15 and HR17 on Unit 1 during the next planned outage [R-13]. The base plate for HR15 and HR17 on Unit 2 requires additional visual inspection before repairs to the concrete are recommended.

The following sub-sections provide specific recommendations for each unit and steam system assessed in this report.

8.1 Unit 1 & 2

8.1.1 Main Steam System

- The conclusions from the stress analysis performed for main stop valve change on the Main Steam system in Unit 2 are acceptable;
- The "as-found" stress analysis for the Main Steam system in Unit 2 can be applied to the Main Steam system in Unit 1, since the hanger and piping configuration between the two units are similar. Any minor differences between the two units will be covered by the margin in the "as-found" analysis;

- Based on the cold and hot walk-downs for Unit 1&2, constant load hanger, MS10, appears to not be moving as per the design. Continued monitoring of MS10 is recommended;
- For pipe hangers that do not exhibit any travel or less than expected travel, further monitoring of pipe hanger readings in the cold and hot condition is required, refer to Section 5.0;
- Maintenance is required on pipe hangers inspected in Appendices A and D that were observed to have findings related to mechanical condition found in Section 6.0;
- The contact area between the trapeze support and the valve insulation at MS15 on Unit 2 is recommended to be monitored to ensure the valve body is not damaged;
- Hanger detailed drawing for MS8/1 and MS8/2 on Unit 1 and 2, [R-7], needs to be updated to match the current installed configuration;
- Field verification for MS14 and MS16 was performed during the 2013 inspection and the isometric drawing will need to be updated to match the field configuration. The analysis will need to be revisited to determine if any changes are required.

8.1.2 Cold Reheat System

- Based on the cold and hot walk-downs for Unit 1, three constant load hangers, CR13/1, CR13/2 and CR14, had vertical misalignment in the rods. Further monitoring of these hangers is recommended before adjustments are made;
- During the cold and hot walk-downs for Unit 2, one constant load hanger, CR23, was identified as being topped out during the cold load. Further monitoring of CR23 is recommended;
- For pipe hangers that do not exhibit any travel or less than expected travel, further monitoring of pipe hanger readings in the cold and hot condition are required, refer to Section 5.0;
- Maintenance is required on pipe hangers inspected in Appendices B and E that were observed to have findings related to mechanical condition identified in Section 6.0;
- Hanger detail drawing for constant load support, CR20, on Unit 2 should be updated to match the current installed configuration [R-10].
- During cold and hot walk-downs for Unit 2, it was identified that the hanger locations for CR2 and CR6 does not match the isometric drawing. It was confirmed during the 2013 inspection that both hangers are of the same type. The isometric drawing should be updated to match the installed configuration.

8.1.3 Hot Reheat System

- During the cold and hot walk-downs for Unit 1&2, a number of constant load supports were identified as being topped out during both the cold and hot load, refer to Section 5.0. Further monitoring of hanger readings in the hot and cold condition is recommended. Unit operations should be reviewed to determine whether system transients are contributing to the hanger problems;

- Trapeze-type constant load supports located near the 4th floor have a vertical misalignment in the hanger rods that may be a result of uneven loading of the constant load supports or distortion of the piping. For the trapeze-type constant load supports, the load should be balanced evenly by the constant load springs on each side of the pipe;
- For pipe hangers that do not exhibit any travel or less than expected travel, further monitoring of pipe hanger readings in the cold and hot condition are required before any adjustments are made, refer to Section 5.0;
- Maintenance is required on pipe hangers inspected in Appendices C and F that were observed to have findings related to mechanical condition identified in Section 6.0;
- Hanger detail drawing, [R-8], for pipe support, HR15 and HR17, on Unit 1&2 will need to be updated to match the current installed configuration shown on CGE drawing, [R-9].
- Plan to perform repairs on the concrete surrounding the base plates for HR15 and HR17 on Unit 1 during the next planned outage [R-13]. The base plate for HR15 and HR17 on Unit 2 requires additional visual inspection before repairs to the concrete are recommended. Continue to monitor these pipe supports for mechanical condition and corrosion.

8.2 Unit 3

8.2.1 Main Steam System

- During the cold walk-down, four constant load hangers MS9, MS10, MS11, MS13 and MS14 could not be viewed due to accessibility. According to the isometric drawing for the Main Steam system piping, MS10, MS11, MS13 and MS14 constant load hangers are located on either side of the main stop valves [R-11]. These hangers were inspected during the hot walk-down and no significant issues were identified;
- During the cold and hot walk-downs, constant load hanger, MS8, was identified as being bottomed-out. Analysis should be considered to determine the reason for the lack of movement of the constant load hanger, MS8;
- Monitoring of hanger readings in the hot and cold condition is required to confirm if the constant load hanger is either topped, bottomed or has no movement, refer to Section 5.0;
- Maintenance is required on pipe hangers that were observed to have findings related to mechanical condition found in Section 6.0.

8.2.2 Cold Reheat System

- During the cold and hot walk-downs, constant load hanger, CR9, was identified as being bottomed-out. Analysis should be considered to determine the reason for the lack of movement of the constant load hanger, CR9;
- During the cold walk-down, it was identified that the rigid pipe hanger, CR R1, has damaged the insulation of the surrounding Main Steam and Hot Reheat lines. It is recommended that the piping surfaces in contact with the rigid pipe hanger, CR R1, are checked for any damage;
- Maintenance is required on pipe hangers that were observed to have findings related to mechanical condition found in Section 6.0.

8.2.3 Hot Reheat System

- During the hot and cold walk-downs, the constant load hangers, HR8 and HR14, were identified as being bottomed-out. Analysis should be considered to determine the reason for the lack of movement of the constant load hangers;
- During the cold and hot walk-downs, the constant load hangers, HR7 and HR13, were identified as being topped-out. Analysis should be considered to determine the reason for the lack of movement of the constant load hangers;
- Monitoring of hanger readings in the hot and cold condition is required to confirm if the constant load hanger is either topped, bottomed or has no movement, refer to Section 5.0;
- Maintenance is required on pipe hangers that were observed to have findings related to mechanical condition found in Section 6.0.

9.0 REFERENCES

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[R-2] A. Ali, Task Notification for Holyrood Condition Assessment Phase 2, AMEC NSS document AM132/RE/037 R00, April 2013.

[R-3] T. Mahmood, HTGS Condition Assessment and Life Extension Study, AMEC NSS Report AM060/RP/001 R0, May 13, 2010.

[R-4] A. Ali, Inspection Plan for High Energy Piping Supports of Holyrood Thermal Generating Station (Level II, Units 1, 2 and 3), AMEC NSS document AM132/PL/002 R01, December 2012.

[R-5] EPRI FMAC Pipe Hanger/Pipe Support Web Cast Training, September 14th, 16th and 23rd, 2004.

[R-6] ANSI/MSS SP-58-2009, Pipe hangers and supports – material, design, manufacture, selection, application and installation.

[R-7] HTGS Dwg. No: 238-10-6022-054 R0, Details of Main Steam MS8/1, MS8/2 and MS11.

[R-8] HTGS Dwg. No: 238-10-6022-158 R1, Details of Hot Reheat Supports HR15/1, HR15/2, HR17/1 and HR17/2.

[R-9] HTGS Dwg. No: 238-10-6001-207, Support Hangers for Main, Reheat Steam Lines.

[R-10] HTGS Dwg. No: 238-10-6022-134 R0, Details of Cold Reheat Supports CR20/2 and CR25/2.

[R-11] HTGS Dwg. No: 1403/V/281/M/024 R0, Isometric of Main Steam Pipe-work and Results of Flexibility Analysis.

[R-12] Hatch Ltd., Main Steam Pipe-work – Main Valve Replacement Stress Analysis Report, H320941-000-P-25-0001.

[R-13] E-mail from A. Ali to Jamie Curtis, "Project: AM132 - Correspondence to document and provide recommendations for the pipe supports, HR15 and HR17, in Unit 1&2," AMEC NSS Correspondence AM132/013/000001 R00, May 9, 2013.

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Holyrood Thermal Generating Station Condition Assessment and Life Extension Study – Phase 2

2014 Level II Condition Assessment Boiler and Steam Piping, Flow Accelerated Corrosion, Units 1 and 3 Generators, Civil Structures

AM160/RP/002 R01

December 5, 2014

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Revision Summary

Rev	Date	Author	Comments
R01	December 2014	T. Ogundimu	Revised to incorporate client comments.
R00	November 2014	T. Ogundimu	Initial issue for 2014 boiler, piping, generator and civil inspections.

Certification Statement

I, the undersigned, being a licensed professional engineer in the province of Newfoundland and Labrador and being competent in the applicable field, have prepared or directly supervised the preparation of this document, following the procedures of the AMEC NSS quality management system.

AMEC NSS document and revision no. AM160/RP/002 R01

Certified by: Blair Seckington

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Date: December 5, 2014

Executive Summary

The Holyrood Thermal Generating Station (Holyrood TGS) consists of three oil-fired generating units with a total nominal generating capacity of 500MW. The units were built in two stages with Stage 1 (Units 1 and 2) being placed in service in 1969/70 and Stage 2 (Unit 3) placed in service in 1979.

Nalcor has a requirement for the Holyrood Thermal Generating Station to operate reliably to 2020 as a generating facility, and for Unit 3 to continue operation as a synchronous condenser to 2041. This is beyond the nominal design life of the units, of approximately 30 years. The objective of the condition assessment and life extension project is to assess the remaining life of the generating units and the related station infrastructure, and to identify actions to achieve the desired life with acceptable reliability. Phase 1 of the project, consisting of a Level I condition assessment, was completed by AMEC in 2011 [R-1].

AMEC was engaged in 2012, 2013 and 2014 to conduct a Level II condition assessment, based on the priorities identified in the Level I assessment. Included in the 2014 segment of the Phase II study, were a number of boiler, piping, civil structures and generator testing reviews, with a focus on Unit 3. This report is considered the final for the Phase II effort. A more comprehensive assessment and recommendations for Units 1 and 2 is provided in the 2012 and 2013 assessment reports [R-11, R-12]

The following report summarises the work completed in 2014, the methods applied, results of the inspections and life assessment, and provides recommendations for further inspections and life management activities on target components. A summary table of the 2014 boiler and high energy piping inspections and results is provided at the end of the executive summary for reference.

Overall, the components evaluated are in good condition. The condition of the Holyrood plant components is similar to other units of similar age. Holyrood has gaps is in the management programs for hangers and FAC. However, upon discovery of an issue, station personnel are quick to address the issue. There are potential life-limiting issues for the economizer inlet headers in Units 2 and 3, and capital expenditure may be required to achieve the desired operating life (2020). The building siding is also at end of life and capital reinvestment will be required to achieve desired life (2041). Monitoring and repair of the siding is required to manage the high safety risk. There are also issues that will need to be managed in order to achieve the desired safety and reliability performance. These issues include thermal fatigue of the economizer inlet headers, potential corrosion fatigue and hanger abnormalities. Flow Accelerated Corrosion (FAC) in the high pressure (HP) feedwater piping and auxiliary systems is also an issue on all three units. It is not considered life limiting to 2020 but reliability and potentially safety issues may be encountered.

The recommendations below are based on results of the assessment in Section 5 and the risk assessment in Section 6, with a focus on Unit 3. Additional recommendations for Units 1 and 2 are provided in the 2013 report [R-12]. Actions should be completed at the earliest opportunity unless stated otherwise below.

In addition to the life assessment, other specific locations are listed below as follow-up to the damage identified in 2014 and previous inspections.

If operation beyond 2020 is forecast, the recommendations need to be reconsidered.

Boilers

The following recommendations are part of the life assessment scope:

1. Complete waterwall inspections for corrosion fatigue on Unit 3 within 2 years. Digital RT is recommended to identify cracking.
2. Inspections in all three units of the feeder tubes between the downcomers and lower waterwall headers to assess susceptibility of corrosion fatigue are warranted within two years due to the potential severity of a blow-out failure. A sample of feeders can be inspected in the neutral access using Phased Array Ultrasonic Testing (PAUT). Priority should be given to feeders with high ovality and low radius bends. This inspection should be performed at the next outage when access to the lower water circuit is possible.
3. A review of lay-up practices for all three units is recommended within 1 year to ensure measures to limit corrosion and pitting of boiler and piping components are being effectively implemented.

The following recommendations should be completed as follow-up to the damage identified during inspections in the economiser inlet headers on all three units:

1. For the Unit 3 economizer inlet header, review of the operating conditions, start-up practices and thermocouple information before the end of 2014 is required to reduce the potential for thermal shock and further advancement of the internal diameter (ID) cracking is reduced. Boiler transients, start-up data and condition of feedwater control equipment should be included in the review. Thermocouple information and start-up data should also be reviewed for Units 1 and 2.
2. Sizing of the cracks in the Unit 3 economizer inlet header should be done in the next outage (within 1 year). If there is crack growth or the crack size exceeds the critical size limit then further assessment will be required.
3. The operating temperature of the Unit 2 economizer inlet header must be monitored to remain below 500^{o}F, or the minimum wall thickness may not be sufficient for the operating conditions. Recent load test information indicated a maximum temperature of 428^{o}F (220^{o}C).
4. Re-inspection of the Unit 2 header is required within one year to confirm wall thinning rates, or replacement of the tee section will be required in 2015. If the tee section is replaced, no repeat UT grid will be required.
5. Based on the Alstom recommendation, re-inspection at 3-year intervals for crack growth on the Unit 1 and 2 economizer inlet headers is advised. If there is evidence of crack growth, an integrity assessment is recommended (one assessment covering both units). An integrity assessment will define critical crack size, growth rate and end of life, and will provide a basis for continued operation without repair and define end of life.

Steam Piping

The following recommendations should be completed as follow-up to the damage identified during inspections:

1. Wall thickness measurements are required at the next opportunity on the 10.75” pipe connected to the Unit 3 main steam east boiler link to disposition the 0.94” measurement reported from the PAUT inspection.

Feedwater Piping

A FAC susceptibility analysis and implementation of management program consistent with industry practice is recommended to assess the full scope of FAC in the Holyrood units. This engineering assessment would be beneficial to target susceptible locations that have not been explored, which may have accumulated FAC damage over the life of the plant. These locations include boiler feed pump (BFP) recirculation lines up-stream of the pressure breakdown orifices, superheat attemperator water supply piping, HP feedwater double elbows and heater drains, shells and vents. Specific actions for Unit 3 identified during the inspections are:

1. Inspection of the west BFP discharge piping at the isolation valve inlet is required within 1 year. Inspection of the valve outlet piping is recommended at the same time.
2. Monitoring of wall loss due to FAC is required on the feedwater system. Inspection of the inlet bend of the superheat attemperator station is required in 2 years.
3. Inspection of the repair above the No. 6 HP Feedwater heater is recommended in 3 years.
4. Use of the HP Feedwater Heater 6 by-pass needs to be investigated within 1 year through a review of station operating records. If the by-pass piping is used regularly, FAC grid inspections of additional sites in the by-pass line, such as the tee upstream of the Heater No.6 inlet and the bends in line 521, are recommended.

Hangers and Supports

The Unit 3 reheat inlet combined stop valve (CSV) hanger collar failures demonstrate need for a hanger program. A hanger inspection and high-energy steam piping management program is recommended to monitor damage accumulation in the piping and condition of the supports to manage steam piping performance over the desired remaining life of all three units. Inspections should be carried out every two years and the results compared. Specific actions are:

1. Review and corrective action is recommended to address minor mechanical issues and to balance loads on the trapeze hangers.
2. The Unit 3 CSV hangers need to be inspected in the hot condition to confirm correct operation (not topped or bottomed out).
3. Monitor pipe hangers in the topped or bottomed out condition, or showing no movement. Conditions where multiple pipe hangers in a system are either topped or bottomed out should be considered for analysis to determine impact on the system piping stresses and load distribution, and on the other pipe hangers. In addition, manufacturer specifications for the pipe hanger should be consulted. Further details are provided in the 2012 and 2013 inspection reports. Topped out hangers may be indicative of a failure as was seen at the Unit 3 CSV inlet.
4. Review and assess pipe support collars in the hot reheat and main steam piping systems at locations with topped out hangers for possible failure.

5. Repairs are recommended at the Unit 1 Hot Reheat supports HR15 and HR17; concrete and mounting plate repairs at the base of the stanchions and possible replacement of the stanchion.

Related to the Unit 3 Hot Reheat hanger collar failure, a review of previous inspection results is recommended, and inspection of hangers that are topped out (unloaded). The Unit 3 event may be an isolated occurrence related to the high load at that location, and an undersized collar, or there may be additional hangers susceptible to the same problem.

Generators

The assessment of for Unit 3 generator recommends:

1. Installation of an on-line flux probe is recommended to allow trending to determine if the short noted in the inspection progresses in magnitude or if more shorts appear.
2. A 10 minute IR measurement is recommended so that a Polarization Index reading can be obtained.

The assessment of for Unit 1 generator recommends:

3. The endwindings, wedges and any other loose components should be re-tightened as required.
4. Another inspection and a bump test are recommended for this generator; it can be done with the rotor in place. This test should be conducted at the next outage where the generator is opened, presumed to be 2016.
5. At the next major outage a thorough cleaning, some additional EW blocking, and a upward shift of the natural frequency are recommended.

Civil Structures

The assessment of the raw water line recommends:

1. A cost benefit analysis should be conducted to determine if replacement or inspection and repair is the most cost effective option.
2. The two areas identified in the AGL report be retested to confirm the status of the pipeline in those areas.

The assessment of the powerhouse siding recommends work on specific areas on all sides of the plant. Recommendations for the inspection and repair of powerhouse siding in order of priority are: the South Elevation, East and West Elevations, North Elevation. The siding is at the end of its life but is required until 2041. Capital reinvestment will be required in the near term. Since the damage will accumulate and at a higher rate as time passes, the repairs should be initiated in 2015. Monitoring and repair is recommended to manage the high safety risk from falling siding.

Table 1 Unit 1, Unit 2 and Unit 3 2014 Boiler and Piping 2014 NDE Results

Unit	Area	Location	Potential Damage Mechanism	Comments
Boiler NDE (2014)				
U3	Boiler (Steam) Drum	General visual of drum internal for major damage	Mechanical fitness	No damage was detected in the general visual and magnetic particle testing (MT) inspections
		Downcomer penetrations – nozzle weld to drum (ID)	Thermal Fatigue	No indications found
		Feedwater nozzles	Thermal Fatigue	No indications found
U3	Riser Tubes	180° bends	Corrosion Fatigue	No indications found
		Straight sections	Corrosion Fatigue Pitting	No indications found
U3	Downcomer	Lower downcomer header	Thermal Fatigue	No indications found
U3	Waterwall	Lower Waterwall header	Thermal fatigue cracking Corrosion-fatigue cracking Corrosion	Small pits (0.040" deep) seen by boroscope inspection. No further action required.
U3	Steam-cooled Roof	Hanger lugs	Fatigue	No indications found
U3	Economizer	Inlet Header	Thermal/Mechanical Fatigue Cracking Corrosion-Fatigue Cracking Corrosion FAC	Cross-ligament borehole cracking. Follow-up investigation is required in 2015, including a review of operating conditions and start-up procedures.
U2	Economizer	Inlet Header	FAC Thermal Fatigue	Borehole cracking due to thermal fatigue. Evidence of FAC. Pad weld applied to increase wall thickness on inlet tee. Re-inspection required unless inlet tee is replaced. A review of start-up procedures is also required.

Unit	Area	Location	Potential Damage Mechanism	Comments
U1	Economizer	Inlet Header	FAC Thermal Fatigue	Borehole cracking due to thermal fatigue. No evidence of FAC. Re-inspection 3 years per Alstom recommendation.
U3	Secondary Superheat Attemperator Header	Inlet and outlet pipe welds	Thermal Fatigue	No indications.
U3	Secondary Superheat Outlet Header (Main Steam Header)	Header Wall/ Internal	Creep Wall wastage from oxide exfoliation	No metallographic evidence of creep. Flaking of scale from inside wall seen. No further inspections required.
		Header outlet nozzle welds	Creep, Weld Defect.	No indications.
		Stub Tubes	Creep swelling, Thermal softening, Wall wastage from oxide exfoliation, Mechanical fatigue cracking due to abnormal system stresses.	No indications.
		Circumferential Seam Weld	Creep cracking Creep-fatigue cracking	No indications.
		Drain	Thermal fatigue	No indications.
		Header supports (50%)	Overload Corrosion Interference with motion	No indications.
		End Cap	Creep	No indications.
U3	Cold Reheat (CRH) (Cold Reheat Inlet) Header	CRH Header Internals - boroscope	Thermal Fatigue	No visual evidence of cracking
		Header Nipples and Perforated Areas	Thermal fatigue	No findings
		Drain	Thermal fatigue External creep/fatigue cracking	No findings
		Supports	Overload	No findings

Unit	Area	Location	Potential Damage Mechanism	Comments
			Corrosion Interference with motion	
U3	HRH (Reheat Outlet) Header	Hot Reheat (HRH) Header Wall	Creep/Creep Fatigue, Thermal Fatigue	No findings
		Header supports (50%)	Fatigue Creep Fatigue	No findings
		Header Girth Welds	Creep/Creep Fatigue	Replicas were taken at the east circumferential welds. No indications were found.
		Outlet Nozzle	Creep/Creep Fatigue	Replicas were taken at the east Tee outlet nozzle and west header welds. No indications were found.
		Drain	Thermal fatigue	Circumferential crack in weld. Repaired.
		Stub Tubes	Fatigue	Sample inspected. No indications identified
Steam Piping NDE (2014)				
U3	Main Steam (MS)	East Boiler Link Thermowell Gamma plug	Creep/Creep Fatigue	MT, PAUT and Replication completed No indications found No evidence of creep voids
U3	Main Steam	Weld below BSV Instrument penetrations	Creep/Creep Fatigue	MT, PAUT, Replica. No evidence of cracking. No creep voids
U3	Main Steam	Upper Y West leg of Upper Y and crotch	Creep/Creep Fatigue	MT, PAUT, Replica. No evidence of cracking. No creep voids
U3	Main Steam	West Main Stop Valve Inlet Weld Instrument penetrations thermowell drain	Creep/Creep Fatigue Fatigue	MT, PAUT and Replication completed No indications found No evidence of creep voids

Unit	Area	Location	Potential Damage Mechanism	Comments
U3	Main Steam	Upper turbine terminal	Creep/Creep Fatigue Fatigue	MT, PAUT and Replication completed No indications found No evidence of creep voids
U3	Hot Reheat	East Boiler Link Thermowell Gamma plug	Creep/Creep Fatigue	MT, PAUT and Replication completed No indications found No evidence of creep voids
U3	Hot Reheat	Lower Y east inlet weld Hanger lug	Creep/Creep Fatigue	MT, PAUT and Replication completed No indications found No evidence of creep voids
U3	Hot Reheat	East and West CSV Inlet and Outlet	Creep/Creep Fatigue	Inlet hanger collar failure. Collar replaced. MT, PAUT and Replication completed No indications found No evidence of creep voids
U3	Hot Reheat	West Turbine Terminal	Creep/Creep Fatigue Fatigue	Area of reduced wall thickness, but above min wall. Likely manufacturing defect; no re-inspection required. MT, PAUT and Replication completed No indications found No evidence of creep voids
U3	Cold Reheat	West Boiler link	Fatigue	MT and PAUT completed No indications found
U3	Cold Reheat	West horizontal run	Pitting Fatigue	UT B-scan completed Minor pitting found. No re-inspection required. Review of layup. Practices to avoid condensate collection recommended.
U3	Cold Reheat	Drain below East Turbine Terminal	Thermal fatigue	MT and PAUT completed No indications found
Unit 3 Feedwater Piping FAC Survey				

	Area	Location	Damage Mechanism	Comments
U3	BFP Discharge	Pump 1 Discharge Piping, TW3553 and downstream Elbows	FAC	Fit for Service Evidence of FAC, re-inspect in 1 year
		Full Flow Tee D/S HP FW Heater 6	FAC	Fit for Service Evidence of FAC. Low Point unrelated to FAC. Pad weld to be re-inspected in 3 years.
		Attemperator Station	FAC	Fit for Service Evidence of FAC. Re-inspection in 2 years.
		Low Flow Line Connection to Main Run		Fit for Service Evidence of FAC. Re-inspection in 4 years.
		Elbow upstream of Economizer inlet	FAC	Fit for Service. Evidence of FAC. Re-inspection in 5 years.

TABLE OF CONTENTS

1.0 INTRODUCTION

Nalcor Energy requires that the Holyrood Thermal Generating Station (HTGS) continue to operate as a generating station until 2020 and Unit 3 as a synchronous condensing facility until 2041. Operation to these dates will result in life extension beyond the original design lifetime of the station, approximately 30 years. Inspection and subsequent assessment of the results is required to identify components and/or systems, which will require remedial measures (maintenance, inspection and/or analysis) to allow the station to continue to operate with high reliability during the extended operating period.

In 2009, AMEC undertook a Level I Condition Assessment of the Holyrood Thermal Generating Station. As a part of this, AMEC NSS participated in the preparation of a Level I Condition Assessment for degradation mechanisms that could adversely affect reliability and safety over the required operating period. Design and historical operating and maintenance data were used as the basis for remaining life assessments. The resulting report included a background summary of industry issues and mechanisms, a summary of the HTGS assessment, a list of issues prioritized by risk to the generating plan (desired life), and an estimated cost for a Level II Condition Assessment of the subject components [R-1, R-2].

Phase 2 of the Holyrood Condition Assessment and Life Extension Study is a Level II assessment of the major issues identified in Phase 1. This report identifies the 2014 portion of the Phase 2 study where a number of Unit 3 piping and boiler components were inspected, limited inspections of piping and boiler components were performed on Units 1 and 2, and civil structures and test results were evaluated for the Unit 1 and Unit 3 generators.

1.1 General Description of Holyrood TGS [R-3]

HTGS has three (3) residual fuel oil-fired units having a total combined output of 500 megawatts (MW) (nominally 150 to 175 MW units). General information on the generating units is as follows:

1. Units 1 & 2 are duplicate, 1970 vintage type units: originally rated at 150 MW; having oil-fired boilers, originally built by Combustion Engineering (now represented by Alstom).

2. Both Units 1 and 2 boilers were designed to generate a main steam (MS) flow rate of 1,050,000 pounds per hour (lb/hr) at an outlet temperature and pressure of 1005 ^{o}F & 1900 pounds per square inch gauge (psig) respectively.

3. Units 1 & 2 were modified from their original design in 1987 by Alstom to produce 175 MW per unit with a revised main steam flow rate of 1,167,000 lb/hr at an outlet temperature & pressure of 1005 ^{o}F & 1955 psig respectively.

4. Unit 3 is a 1980 vintage type unit: rated at 150 MW; having an oil-fired boiler originally designed and built by Babcock & Wilcox (B&W).

5. Unit 3 has a main steam flow rate of 1,072,000 lb/hr at an outlet temperature & pressure of 1005°F & 1890 psig respectively.

6. Unit 3 was modified in 1986 to permit the generator to be decoupled from the steam turbine for operation as a synchronous condenser (SC).

7. Typically, the plant operates seasonally base-loaded between December and March, but on a daily load cycling basis with each unit running between 70 MW & full load. Full plant capacity is needed to meet the winter electrical requirements of the Island Interconnected System. For much of the rest of the year, generation from some or all of the units is not required. Often during the summer when customer demand is at its lowest, no generation is required but Unit 3 is required to operate as a synchronous condenser for system stability purposes.

8. As of April 30, 2014, the operating hours for each unit are as follows [R-4]:

Unit 1	185,827 hrs
Unit 2	178,628 hrs
Unit 3	139,821 hrs
Unit 3 (as a synchronous condenser)	47,603 hrs

9. The existing fuel system includes the following:

   - A heated delivery pipeline, approximately 0.75 km long from the ship to the tank farm.

   - Four (4) 220,000 barrel (bbl) main fuel oil storage tanks, which are un-insulated and unheated with the exception of the suction heaters.

   - A gravity flow pipeline between the main fuel oil storage tanks discharges to a common 4000 bbl day tank.

   - A common 4,000 bbl day tank, which supplies fuel skids for each of the three (3) units.

10. Each boiler is equipped with two (2) forced draft fans and uses both regenerative air pre-heaters and steam coil air heaters prior to combustion.

11. Flue gases are discharged into a single stack for each boiler. Each stack is located immediately north of the main building.

12. All three generating units are controlled remotely through a Foxboro distributed control system (DCS) system.

The following is a list of major equipment upgrades that have been completed:

Major Upgrades	**Year**
• Upgrade Unit 3 to operate as a synchronous condenser as mentioned in Item #6 above	1986
• Up-rate Generation Units 1 and 2 (150 MW to 175 MW) as mentioned in Item #3 above	1987
• Replace Boilers Breeching	1990
• Upgrade Boiler Air Pre-heater Steam Heat Exchanger	1990
• Replace Roof and Upgrade Siding	1990-2000
• Construct New Water Treatment Plant	1992
• Install Warm Air Make-up System	1992
• Construct five Ambient Air Monitoring Stations	1993
• Construct New Wastewater Treatment Plant	1994
• Install Boiler Soot Blower	1995
• Replace Unit 1 Boiler Stack Liner	2000
• Replace Uninterrupted Power System	2000
• Remove/upgrade reheater tube surface from Unit 3	2001
• Replace Unit 2 Boiler Stack Liner	2001
• Upgrade Unit 1 and 2 Exciter	2002
• Upgrade Units 1, 2, and 3 Controls System	2002-2003
• Replace Heating, Ventilation & Air Conditioning Units	2002-2005
• Upgrade Unit 1 and 2 Governor Controls	2003
• Install Continuous Emissions Monitoring System (shared)	2003
• Plant Asbestos Removal Program (3 year project)	2003-2006
• Construct New Security Building	2004
• Replace Boiler No. 2 Partial Water Wall and chemical clean	2006
• Chemical clean of Unit 1	2007
• Replace Boiler No. 2 Superheater	2007
• Install Cooper Ion Injection System	2007
• Replace Boiler No. 1 Superheater	2008
• Replace Unit 2 Boiler Stop Valve	2008
• Boilers Internal Cleaning, Inspection and Minor Repairs	annually

- Turbine/Generator Valves Disassembly, Inspection and Repair (each Generation Unit) — every 3 yrs
- Major Turbine/Generator Disassembly, Overhaul and Repair (each Generation Unit) — every 6 yrs

1.2 Unit 3 Generator

The Unit 3 Generator is a tandem-compound, 2-pole machine, manufactured by Hitachi. It is rated at 177 Mega-Volt-Amperes (MVA) at 0.85 power factor (pf) lagging (i.e. 150 MW), with a terminal voltage of 16 kilovolts (kV). Both the stator and rotor windings are indirectly cooled by hydrogen at 207 kilopascals (kPa) (30 psi). The generator has an overload rating of 185 MVA at 310 kPa (45 psi), providing 157 MW at 0.85 pf. It was manufactured in 1979 and went into service in 1980.

In 1986, the generator was modified to operate as a synchronous condenser to provide voltage support to the Island Interconnected transmission system for electrical power that is transmitted over large distances. The synchronous condenser drive includes a Siemens 4 kV, 1500 horsepower induction drive motor (pony motor), a Philadelphia Gear Starter Drive Gearpak (Model HL60/9HS), and a SSS Clutches Size 60T SSS Clutch and casing assembly, as well as associated auxiliaries (extension shaft, flexible coupling, hydraulic transmission).

1.3 Unit 1 Generator

The Unit 1 generator is rated at 194,445 KVA, hydrogen-cooled, supplied by Canadian General Electric, Peterborough. 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 and are indirectly cooled by hydrogen. The hydrogen is circulated throughout the generator in a closed system, at 310 kPa (45 psi) pressure, by an axial fan mounted on each end of the rotor. 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 the hydrogen from escaping around the rotating shaft. 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.

1.4 General Description of Raw Water Line

The raw water line that feeds the Holyrood Thermal Generating Station runs from Quarry Brook Dam to Pumphouse Unit No. 3. The line consists of 18" " SCLAIR" pipe (lightweight, solid wall high density polyethylene (HDPE) pipe) and 16" asbestos-cement (AC) pipe.

The raw water line runs from Quarry Brook to the stage 1 and stage 2 pumphouse. The line is 16" pipe from the brook with an 18" SCLAIR pipe segment leading to the Unit 3 pump house. Between the Unit 1 and Unit 1 and 2 pumphouse is a segment of SCLAIR pipe followed by asbestos-cement (AC) piping. The line supplies water for all steam generation purposes. The pipe is approximately 3300 feet in length.

1.5 Powerhouse Siding

The original building's exterior wall is comprised of an insulated steel siding system which spans vertically between the Plant's horizontal structural members. Spans vary but can be seen to be approximately 2.1 meters (m) (7'-0") on center. This type of wall system was assembled by securing a steel liner directly to the horizontal steel members. Then, notched Z-bars were secured to the liner sheet at approximately 1200 millimeters (mm) on center (o.c.) vertically as intermediate members. Finally, the exterior steel siding was secured to the notched Z-bars with the space between the sheets filled with batt insulation. Note that the spanning ability of two steel panels acting in tandem as described above affords a greater vertical span that single sheet steel siding acting alone.

2.0 PROJECT DECRIPTION AND SCOPE

2.1 Study Basis [R-3, R-4]

The basis for the study is as follows:

- 2014 to 2018, Units 1 to 3
    1. Annual Capacity Factor (ACF)/pattern:
        - ACF between 30% and 75% until 2018
        - Total starts expected to increase
    2. Reliability: high, similar to current
    3. Condition Assessment and Life Extension Schedule:
        - Phase 1 -2010
        - Phase 2 – 2012 to 2014 (previously planned to conclude in 2013)
        - Implementation – 2014 and beyond

- 2018-2021 Generation Standby, Units 1 to 3
    1. Capacity required: ACF/Operating pattern: up to 10%
    2. Hot/cold standby – time for return to service, and
    3. Reliability/availability of generation

- 2021, Decommissioning of Units 1 and 2

- 2021 to 2041 Synchronous Condensing, Unit 3
    1. Capability (generator, transformers) – similar to current Unit 3 role

2.2 Focus

The objective of Phase 2 of the Holyrood Thermal Generating Station Condition Assessment and Life Extension Study is to assess potential degradation problems, and validate or revise remaining life predictions for the major components and systems selected by Nalcor based on the Level 1 Condition Assessment completed in 2011 [R-1]. The project was also to provide the technical basis for a maintenance and repair program, including potential Level III activities that will assure continued operation with the desired level of reliability, over the target lifetime. The present effort is considered the final segment of Phase 2 and further actions will be managed by Holyrood TGS through maintenance contracts.

The inspection scope of work for the project was defined in the contract agreement 2014-57571 [R-3]. The scope focused on NDE inspections of the boilers and high-energy piping in Unit 3, limited boiler inspections in Units 1 and 2, Unit 1 and 3 Generator testing and civil structure inspections. The scope identified in the contract documents is provided in Appendix A, marked to indicate the work completed in 2012, 2013, and 2014. The scope of work for 2014 was modified again in the field as described in the Sections 3.2 and 4.1.

3.0 METHODOLOGY

3.1 Background Information and Studies

The Holyrood Condition Assessment and Life Extension Study Phase 2 is to be conducted on the boiler, and high-energy piping using the Electric Power Research Institute (EPRI) Condition Assessment methodology identified as Level II as outlined in Table 2, and described in more detail in the Phase 1 report [R-1]. Where the Level I assessment is based on design data and operating records, Level II augments the information with inspection data to refine life estimates and confirm expected degradation concerns. The primary method of obtaining the additional information is through Non-Destructive Examination (NDE).

For the present project, the Level I boiler and pressure piping assessment completed by AMEC NSS in 2010 [R-2], was used as the basis for the Level II assessment.

Table 2: EPRI Condition Assessment Level of Detail

Feature	Level I	Level II	Level III
Failure History	Plant records	Plant records	Plant records
Dimensions	Design or nominal	Measured or nominal	Measured
Condition	Records or nominal	Inspection	Detailed inspection
Temperature and pressure	Design or operational	Operational or measured	Measured
Stresses	Design or operational	Simple calculation	Refined analysis

Feature	Level I	Level II	Level III
Material properties	Minimum	Minimum	Actual material
Material samples required	No	No	Yes

3.2 Field Investigation

A project kick-off meeting was held on May 2, 2014 to refine the Unit 3 inspection scope. Scope refinement was based on preliminary field inspections, recent inspection history, and accounted for the annual boiler inspection scope to remove any overlap. Inspections were placed into high and low priority. The low priority items were dropped from scope in order to accommodate the inspections into the limited outage window.

Major adjustments to the 2014 effort include:

- Inspection of the Unit 3 waterwall tubes for corrosion fatigue was removed from scope,
- Inspection of the High Temperature Superheater primary-secondary front vertical spaced inlet header was removed,
- The main steam and hot reheat west boiler links were changed to the east boiler links,
- The hot reheat east turbine terminal was changed to the west terminal,
- The cold reheat east turbine terminal was removed,
- Feedwater piping inspection scope was modified to remove the following inspection locations: boiler feed pump 45 degree branch and reducer, tees to low flow and reducer, Low pressure Feedwater flow element above low pressure heater #2,
- The superheat attemperator feedwater station and bypass were added to the FAC scope,
- Inspection of the hot reheat east combined stop valve was added due to finding of a failed hanger at the west combined stop valve inlet,
- Inspection of the Unit 2 Economizer inlet header was added,
- Inspection of the Unit 1 superheater (SH) SH3-SH4 link piping and riser tubes was removed based on the results of inspections in Unit 2,
- Inspection of the Unit 1 Economizer Inlet header was added (based on Unit 2) results.

The 2014 scope focussed on Unit 3 and included boiler, steam piping and piping supports. Specific inspections were:

- Main Steam east boiler link, Upper Y, boiler stop valve, west main stop valve and west upper turbine terminal,
- Hot Reheat east boiler link, lower Y inlet, west and east combined stop valves, west turbine terminal,
- Cold Reheat west boiler link, west horizontal run from turbine, east drain connection below the turbine,
- Locations on the feedwater piping for investigation of FAC,
- Boiler secondary superheat outlet header (main steam), internal condition, wall thickness, supports, circumferential seam welds, header nipples, end cap, drain, and replication of the outlet tee and girth welds,
- Boiler reheat outlet header (hot reheat), wall thickness, circumferential seam welds, header nipples, drain, and replication of the outlet tee and girth welds,
- Boiler reheat inlet header (cold reheat), internal condition, wall thickness, OD ligaments, header supports, header nipples, and drain.

The scope of the generator assessment was:

- Evaluate the results of testing on the Unit 1 and 3 generator rotor and stator completed by Alstom. This assessment was limited to the generator stator and rotor. There was no assessment of the Unit 3 generator auxiliaries, including exciters, and synchronous condenser drive.

3.2.1 Project Preparation

AMEC NSS was responsible for providing technical direction to the support services contractor (B&W) and NDE contractor (Team Industrial Services). AMEC also provided modifications into the proposed condition assessment work scope. Appropriate on-site training was provided for AMEC personnel.

The work scope, listing the inspection locations and inspection type, was provided to the NDE contractor and the support services contractor to direct the inspections. Qualification of the NDE contractor was the responsibility of Nalcor.

Project preparations from previous Phase 2 inspections were used where possible. The NDE contractor (Team Industrial) was hired through Nalcor. Team Industrial made use of their own NDE specifications and procedures. For Unit 3 a previously prepared FAC report was used as a guide for a proper FAC inspection [R-5]. Other boiler and steam piping inspections were carried out by the NDE contractor.

3.2.2 Site Mobilization and Execution

Site mobilisation was the period where the inspection and support personnel and equipment were moved to site, and work plans, locations and procedures, safety plans, and training were finalised. In 2014, AMEC NSS engineers were at site for the initial period to identify and review the specific locations for inspection. One AMEC oversight personnel remained at site for the duration of the Unit 3 condition assessment inspection activities. There was no on-site support during the Unit 2 or Unit 1 outages. A second visit was made by the technical lead at the beginning of the NDE campaign.

Generator testing was conducted by the generator maintenance contractor, Alstom. This included static testing of the Unit 3 Generator and robotic visual inspection –Diagnostic Inspection with Rotor in Situ (DIRIS) –of the Unit 1 generator.

AMEC arranged for Afonso Group Ltd (AGL) to perform leak detection services using an above ground acoustic listening lead detection system. AGL completed the underground leak detection from the Quarry Brook Dam to the Pump House. The approximate length of the pipe system tested is 3300 feet. The testing began at Quarry Brook Dam and a reading was taken every 15 feet from the Dam up to station 2235.

AMEC sent two individuals with extensive experience in the design of steel clad buildings to conduct a visual inspection of the Holyrood Thermal Generating Station. They visited the plant on three separate occasions and generated findings and recommendations based on visual analysis and, when accessible, actually handling the siding to assess its condition.

3.2.3 Screening

In 2014, preliminary results for the FAC inspections were provided to AMEC NSS as they were generated. Results of magnetic particle testing (MT) and phased array ultrasonic testing (PAUT) inspections were reported informally. Draft ultrasonic testing (UT) wall thickness inspection information was retrieved from the inspectors where possible. Final reports were supplied by e-mail. The purpose of the screening was to determine if immediate action or repair was required. The pass criteria was at least one year of safe operation.

3.2.4 Data Analysis

Analysis consisted of the generation of the expected remaining life and recommendations for life management activities. The methods applied are described in Section 3.2.1 (d), and in the AMEC NSS project work plan [R-4].

4.0 INSPECTION RESULTS

A summary of NDE inspections completed and results for the work 2014 are provided below and in Table 1. Further details of the 2014 NDE results are provided in the NDE report reference binder [R-6]. The Unit 2 and 3 FAC inspection results are reported in Appendix A. The assessment of the inspection results is in Section 5.0.

Results for the civil structures and generator inspections which took place in 2014, are provided in the reference binder [R-6]. The assessment of the inspection results is in Section 5.0.

4.1 Inspection Results

4.1.1 Unit 3 NDE

NDE on the Unit 3 boiler and piping was conducted during May of 2014. Repairs were conducted by B&W as the need was identified. The scope of work completed in this period included scaffolding, insulation, NDE, repair where necessary, restoration of insulation and removal of scaffolding. Due to outage schedule restrictions, inspection locations were prioritized and low priority locations and inspections were removed from the scope. Access restriction also resulted in modification of the inspection scope in the field.

In the feedwater piping, UT wall thickness measurements were taken at regularly spaced locations on a grid. This data provided profiles of wall thicknesses necessary to determine if the pipe walls were being thinned by FAC. Evidence of FAC was apparent in the piping, but in most cases the estimate rate of thinning does not pose a concern for the current target life. Exceptions are identified in Table 1 and a repair done at one location is described below.

The Unit 3 economizer inlet header was inspected internally, using a boroscope. Cross-ligament cracking and a crack in the weld of the drain were observed. Boroscope inspection of the other headers (lower waterwall, downcomer header, main steam, hot reheat) did not find any concerns.

Access to the headers inside the south header vestibule was limited to the east side, and the main steam and hot reheat headers were found to be completely insulated. The insulation was removed from the east-most third of the main steam and hot reheat headers –the inspections were done on these exposed areas.

The header end cap of the hot reheat header could not be examined externally. The gap between the end of the header and the internal vestibule wall was not sufficient for any NDE. The vestibule wall was open on the east side to the facilitate access and ventilation to the space, which also exposed nearly half of the main steam header end cap. This end cap was examined as much as possible with PAUT and no indications were found. It should be noted the access was not sufficient for a proper inspection; despite this, no further inspection is deemed necessary.

Inspection of the main steam piping components did not find any indications of creep damage. As was expected, replication revealed that the microstructure of the steam piping (high temperature seamless SA 335 P22) had aged with small, spherical carbide particles apparent in a ferrite matrix. This is consistent with previous metallographic findings from Units 1 and 2 in 1987 and 2002, respectively [R-2]. This ageing is typical and does not present an integrity concern at this time. A macro etch of the piping at the boiler link found no weld seam.

Hot Reheat and Cold Reheat piping inspections did not find any defects from possible in-service degradation mechanisms that required repair. Replication confirmed ageing of the material but it does not present an integrity concern for the target life. Pitting was identified in a UT thickness scan of the cold reheat horizontal run on the second floor but the wall loss does not affect the pipe integrity. What is expected to be a manufacturing defect in the wall thickness profile of the hot reheat west turbine terminal was found; no repair was required.

The hot reheat turbine terminal was switched from the east side to the west side, as access to the east side was difficult due to the presence of other components. The hot reheat turbine terminals are symmetrical and there are no effects expected on the results of the inspection due to this change. Inspection found an unusual wall thickness profile; the wall thickness decreased to a minimum reading of 0.074” where the average for the same pipe segment is 0.869”. This thinner area was unexpected but it does not present an integrity concern.

During inspection of the combined stop valve inlet, the hanger collar was found to have failed. Inspections were expanded to the east side where the collar there was also found to have failed. The inspections of the hot reheat pipe and pipe to valve welds found no defects due to ageing or the abnormal hanger loading caused by the hanger failures. Inspection of the hot reheat CSV was expended to include the outlet of the west CSV and both the inlet and outlet of the east CSV. No indications were found.

4.1.2 Unit 2 NDE

The 2014 NDE inspections were executed on Unit 2 in July. Neither the UT nor radiographic testing (RT) inspections identified any issues in the boiler waterwall riser tubes. A macro etch of the boiler SH3 to SH4 link piping did not find a seam weld. Wall thinning due to FAC is evident in the HP feedwater piping downstream of HP feedwater heater No.5 but does not pose an integrity concern at this time; re-inspection in 6 years in recommended. Internal boroscope inspection of the economizer inlet heater found evidence of FAC. Borehole and ligament cracking were also seen, with cracks extending into the tubes. This damage is worse in the centre of the header length and is less severe towards the ends. Comparison with thermal fatigue cracking identified in 2010 indicated there was no crack growth. Pad welds were applied to build up the wall thickness to maintain the 1973 (year of design) American Society of Mechanical Engineers (ASME) code requirements. No repairs were considered necessary to address the borehole cracking. Follow-up will be required within 1 year to trend wall loss, determine if further repairs are necessary, or for replacement of the inlet tee.

4.1.3 Unit 1 NDE

Unit 1 inspection took place in August of 2014. Due to the degradation seen in Unit 2 the economizer inlet header was selected for inspection. Again, borehole and partial ligament cracking were identified. The UT wall thickness inspection also found evidence of wall thinning but not to the extent seen in Unit 2. Comparison of the borehole cracking identified in 2010 indicated there was no crack growth. No repairs were made. Although the designs of Units 1 and 2 are the same, the process water in each unit is separate. Differences in the water chemistry or trace alloy content in the material may have led to conditions to accelerate the FAC degradation in Unit 2.

4.1.4 Unit 3 Generator

During the annual Unit 3 generator maintenance outage, testing was carried out on the generator. Alstom, the station’s existing turbine and generator service provider conducted the tests. These tests are a further investigation from testing conducted in 2013. At that time it was noted that an inter-turn short was present in the rotor. The 2014 tests were conducted to measure the magnitude of any change.

The inspection results noted that the shaft voltage measurements are considered low. At least one (1) shorted turn in one location is apparent from the test results, but does not present an immediate concern since no vibration issue was reported.

Based on the available information, there is no immediate concern with the rotor ground or inter-turn insulation.

4.1.5 Unit 1 Generator

The Unit 1 generator was opened for a minor inspection. DIRIS and WInding DIagnosis PROgramme (WIDIPRO) inspections were performed. The generator and in particular the stator winding were thoroughly inspected. It shows signs of ageing consistent with this type of generator. Based on the available information the generator will operate to 2020 will only the normal maintenance. Beyond that, major refurbishments such as rewinds, need to be considered.

4.1.6 Raw Water Line

One-hundred and fifty (150) acoustic readings were taken on the raw water line. The majority of the areas tested no reported no leaks. The only two areas that had any significant readings were station 665 and between stations 805 and 940. It should be noted, however, that the technician only indicated a "medium" potential for a leak at station 665 where an acoustic reading of 123 was reported. The high readings between station 805 and 904 were most likely caused by the testing conditions, notably the high winds; the acoustic readings in for these points ranged from 89 to 593.

There was no testing completed beyond station 2235 because there was some underground disturbance from the hydro station. AGL prepared a report outlining the findings, which have been included in the reference binder [R-6].

4.1.7 Powerhouse Siding

The visual inspections of the wall system resulted in several findings. A section of the steel siding was found to be missing from the south elevation, apparently having been dislodged during the previous winter and blown off the roof. The exterior siding varies in its condition from small areas of missing material to extremely rusty solid construction. The original Galbestos paint finish also varies in condition from flaky to good. Most of the deteriorated siding is on the south elevation primarily at the bottom of the walls and over openings such as doors and louvres. The detailed findings can be found in the AMEC inspection report provided in the inspection binder [R-6].

4.2 Damage Findings and Repair

4.2.1 Unit 3 Feedwater Piping

Inspection of the piping downstream of the Unit 3 No. 6 HP feedwater heater found a location on the pipe where the wall thickness was 0.980". The calculated pressure-based ASME code (1973, design year) minimum wall thickness is also 0.980". The low point was on the intrados of the second bend after the heater (before the tee); see Figure 1. A repeat inspection using a smaller grid size was performed. The smaller grid resolved the low spot into two points with wall thicknesses of 0.980". This low thickness reading does not display a wall thinning profile typical of FAC, where the thinning is spread over the ID of the pipe and has a gradual profile. The profile of this defect is sharp and is therefore not likely to be have been caused by FAC. Regardless of the source of the defect, a repair was necessary to provide some margin on the wall thickness. A pad weld was performed by B&W leaving the welded area with an average wall thickness of 1.084" and a minimum thickness of 1.038". This thickness is sufficient to reach the target end of life but re-inspection in 3 years is recommended.

Additional locations are recommended for re-inspection in 1 or 2 years, such as the attemperator feedwater station and the west boiler feed pump. The superheat attemperator feedwater station, on the 8th floor, west side of the boiler, was modified in 2010 according to the available drawing. Calculations for the new 90^{o} bend installed at the inlet before the block valve indicate that re-inspection in 2 years is necessary. This assumes that the variation in wall thickness observed is due to FAC and not a variation in the manufactured thickness of the bend itself. A repeat inspection is recommended to confirm thinning. Re-inspection is required within 1 year in the west boiler feed pump discharge pipe, and downstream of the isolating valve. All other locations inspected for FAC indicated margin enough for the target life with re-inspections recommended in 4 years time or greater. Further details can be found in the FAC report [R-7].

Figure 1: Unit 3 No. 6 Feedwater Heater Low Wall Thickness Location

4.2.2 Unit 3 Cold Reheat Piping

A segment of the cold reheat piping was selected for UT wall thickness examination. The span across the second floor where steam from the turbine is returned to the boiler has the potential for condensate to pool during shutdowns. This is particularly true downstream of the check valve which could impede the flow of condensate to the upstream drain. The presence of condensate on the SA 106 Grade C carbon steel can lead to pitting at the bottom of the pipe. In order to determine the extent to the pitting a UT B-scan was performed on the west cold reheat line. All the reported measurements were above the 1973 (year of design) ASME code pressure-based minimum wall thickness of 0.340". The lowest thickness of 0.587" was found at the bottom of the pipe. Comparison to the adjacent points suggest that this could be a pit. There is a concern that pits can act as initiation sites for thermal fatigue. No indication of cracking was found in any of the other cold reheat piping inspections. The hanger inspection from 2013 found no obvious indications of sagging between pipe supports in Unit 3 [R-17]. Only one cold reheat hanger was noted not to have changed from the hot to cold condition (CR9, on the east run between the turbine and the check valve). The movement of the other hangers implied from the report, indicates a small potential for thermal fatigue, but the movement is not severe enough to be a concern. A review of lay-up procedures is recommended to prevent the pooling of condensate and prevent further pitting. No re-inspection is required.

4.2.3 Unit 3 Hot Reheat Piping

The turbine terminal of the hot reheat piping was selected for PAUT inspection to look for creep damage. Part of the procedure for PAUT is a lamination scan to identify indications that may interfere with the PAUT inspection. During the lamination scan an unusually low wall thickness was noted of 0.74". The 1973 (year of design) ASME minimum wall thickness is 0.692". A follow-up inspection was performed using a grid to map the thicknesses and determine the wall thickness profile of the area. The lowest reading on the grid points was 0.778" (the 0.74" point fell between grid points). Several grid points were identified to be below 0.800" but all were above the 12.5% mill tolerance of about 0.722". Extension of the UT grid further upstream noted that the slightly thinner area came to an end about 10 inches upstream of the weld to the turbine.

Another wall thickness inspection was performed on the second bend upstream of the turbine (a 90^{o} bend). No thinner areas were noted; the lowest recorded thickness was 0.922". Since all locations were above the ASME minimum wall thickness, no intervention was necessary. No active degradation mechanism was attributed with this thinned area; it is considered to be a manufacturing defect and does not require further follow-up.

4.2.4 Unit 3 Hot Reheat Piping Support Hanger

During inspection of the inlet pipe of the west combined stop valve (CSV), the hanger collar for the 16" inlet pipe was found to have failed. The presence of the pipe insulation had previously hidden the failure. Concern for the east CSV hanger collar precipitated investigation of the collar there as well –the hanger was also found to have failed. Investigation into the failure, replacement of the hanger collar and installation of the new collar was captured under a separate project in conjunction with the maintenance contractor, B&W. The cause of the hanger failures was temper embrittlement (see

Appendix E). The Inspection of both inlet and outlet CSV welds on both the east and west side found no indications of damage caused by the hanger failure or otherwise.

4.2.5 Unit 3 Reheat Outlet Header (Hot Reheat) drain

The reheat outlet header has a single drain at the east end, 3 feet from the end of the header. Visual examination of the drain found a circumferential crack at the drain pipe weld to the header (see Figure 2). MT examination confirmed the presence of a crack 300^{o} around the weld.

A repair was performed on the drain weld. MT examination was performed on the weld prep area to confirm the crack has been sufficiently removed, following welding (prior to heat treatment), and after post-weld heat treatment (PWHT). No indications were identified and header was deemed fit for service.

Figure 2: Unit 3 Hot Reheat (Reheater Outlet) Header Drain Crack

4.2.6 Economizer Inlet Headers

The economizer inlet header of Unit 3 was subject to an internal boroscope inspection. The inspection found cracking in the ligaments between the header tube perforations. The cracks occur on the short ligament between the boreholes, which means they are circumferentially oriented. The cracks also extend into the borehole. A crack was also observed in the weld bead of the butt weld near the economizer drain (see Figure 3). The butt weld crack is considered to be of no consequence. A disposition for the ligament cracking damage was performed under a separate project for the maintenance contractor, B&W. The disposition indicates that the cracking did not pose an integrity concern at this time, though recommendations were made for follow-up assessments [R-8].

Based on the findings of the Unit 3 economizer inlet header inspection, the Unit 2 header was also inspected. The boroscope inspection found cracking in the Unit 2 header, at the boreholes that extends into the ligaments and into the tubes. The images also indicate a significant amount of material loss. For instance, some areas of the backing bar have been corroded away (see Figure 5b). The wall loss was quantified by UT wall thickness measurements, collected in a grid on the inlet tee, and extending to the header spans. Several areas were noted to be thinned with the lowest measurement reading 0.932", which was suspected to be below the minimum wall thickness. Disposition of the wall thickness measurements was conducted by AMEC and various minimum wall thickness were determined based on the part of the tee and the header. Following information can be found in reference [R-9].

A number of locations were found to be below the minimum wall indicated in the available drawings [R-10, R-11]. ASME Section I [R-12], reinforcement calculations were performed to determine the minimum wall thickness and provide guidance for disposition. These calculations used the design information of a forging fabricated from SA515 Gr.70 plate rolled, seal welded and forged into a Tee. The Unit 2 operating condition assumptions were a pressure of 2250 psi and temperature of 500^{o}F. The pressure matches design. The temperature is below design (655^{o}F), but is considered a bounding value based on the No. 6 feedwater heater outlet temperature from the Stage 1 heat balance diagram at 100% load [R-12], and assuming no change in feedwater temperature after unit uprate.

The calculations determined that the tee required a wall thickness of 0.93" in the run (header section), and a 1.06" thick nozzle to meet the Section I code requirements. To provide some additional life margin, run measurements below 0.94" and nozzle measurements below 1.06" were flagged. Calculations indicated that a 0.87" thickness is also sufficient for the SA106-B header wall.

Options for remediation of the thinned areas were considered, including determining the stresses and local minimum wall by finite element analysis (FEA) and API 579/FFS-1 assessment or reduction of the operating pressure (and unit capacity). The option for a pad weld to build up the thickness of the thinned areas based on the reinforcement calculation was selected. The low reading of 0.932" was below the calculated minimum wall thickness when .01" of margin is used. Another area between the platens was also near this limit. Pictures of the pad weld are given in Figure 4. Re-inspection of the tee is required in 1 year, or the tee can be replaced and no re-inspections are then required.

Figure 3: Unit 3 Economiser Inlet Header Cross-ligament cracking and Butt Weld Surface Crack (near economiser drain)

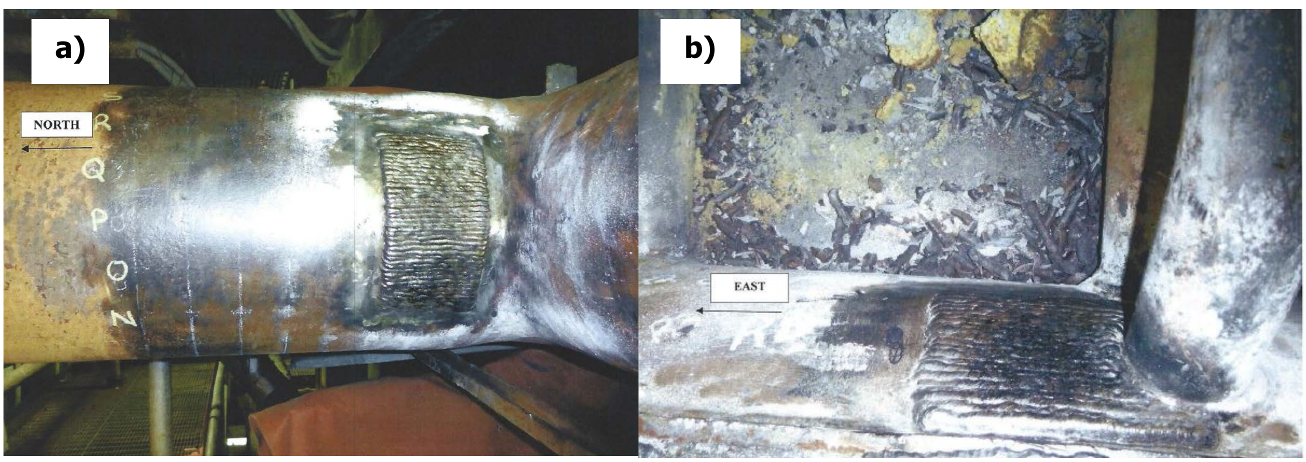

Figure 4: Unit 2 Economiser Inlet Header Pad Weld, a) Tee Inlet, b) Tee between platens.

The economizer inlet header of Unit 1 was also selected for inspection. Once again cracking was observed at the boreholes with some cracks extending into the ligament between holes, into the boreholes and in to the economizer tubing. The wall thickness measurements again found indications of FAC but not to the extent as was seen in Unit 2 (see Figure 5). Images from the internal inspection indicate that FAC damage is not as severe as Unit 2. There was no need for repairs in the Unit 1 economizer inlet header. Per the Alstom recommendation, re-inspection should be carried out in 3 years.

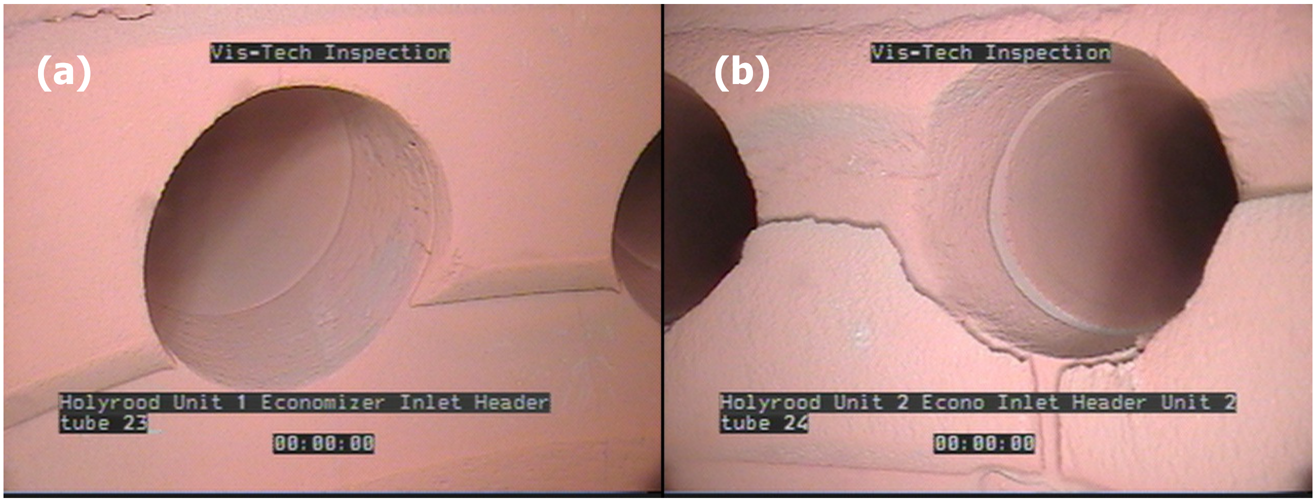

Figure 5: Economiser Inlet Header (a) Unit 1 and (b) Unit 2 Comparison

4.3 Creep Damage

Creep damage occurs naturally in metals at high temperature and under stress. The temperature requirements for creep for carbon and alloy steel are dependent on alloy content. For carbon steel, the creep limit is about 375°C [R-14]. Advance creep damage will lead to crack initiation and growth, and eventually, failure.

Inspection for advanced creep damage was investigated by in-situ replica metallography. The technique was used to visually detect creep void formation in the material microstructure. Replicas were taken across selected welds to capture samples of parent material, heat affected zone (HAZ), and weld metal microstructures. Locations and results are identified in Table 1, and in the replica report is contained in the project reference binders for the 2014 inspections [R-6].

Replicas were taken in Unit 3 at various locations of the main steam piping, main steam header, hot reheat piping and hot reheat header. The original microstructure of these P22 components is expected to be lamellar (layered) pearlite colonies in a ferrite matrix. Over an extended time at high temperatures the carbides migrate away from the perlite colonies to agglomerate as carbide particles. The microstructures observed in the replicas on Unit 3 consisted of spheroidized carbide particles in a ferrite matrix. In some locations, lamellar pearlite colonies are still evident, while in other locations the carbide has migrated into the evenly spaced particles seen in the micrographs. No evidence of creep void formation was seen in any of the examined locations. Additionally, macro-etching was also performed on locations on the main steam and hot reheat piping to determine if there were any longitudinal seam welds. No welds were evident.

4.4 Wall Thickness Measurements

Wall thickness measurements were taken on the boiler components and steam piping that operate at temperatures supporting creep (greater than about 375 °C). The thicknesses are used to support the creep rupture life calculations that define end of life due to creep. Results from Unit 3 are used in the creep life calculations presented in Appendix C.

The Unit 3 measurement results are summarised in Table 3. Not all data was used due to inconsistencies in reporting, where reported measurements are far below the mean expected and calculate minimum wall thickness. In particular this occurred for the main steam east boiler link piping. The requested UT data was only reported on the boiler link, not the main steam pipe. A PAUT lamination scan recorded the wall thickness measurement as 0.94", below the main steam minimum wall thickness of 1.23". This is suspected to be an erroneous measurement and a repeat inspection is recommended to determine the wall thickness.

Using the remainder of the data, it was found that not all Unit 3 measurements were above the minimum thicknesses used in the creep life calculations from the Level 1 assessment, however all measurements were above the ASME code minimum wall thickness. There were two locations that were below the minimum wall used in the creep life calculations: the main steam boiler stop valve outlet, and the hot reheat west combined stop valve inlet. The creep life calculations for this these locations were updated to ensure that the estimated creep end-of-life exceeded the estimated plant end of life. No repeat inspections are required.

Wall thickness measurements were also taken at other locations to verify the component dimensions. These results can be found in the reference binder [R-6]. Thicknesses on the lower water wall header and down comer header were measured. All measurements were above the specified wall thickness in the construction drawings.

Table 3 Unit 3 Wall Thickness Measurement for Creep Life Assessment

	HRH East Link	HRH West CSV Inlet	HRH West Turbine Terminal	HRH Lower Y Inlet	MS East Link	MS West Main Stop Valve	MS BSV Outlet	MS West Upper Turbine Terminal	Hot Reheat Header	Main Steam Header
pressure-based minimum wall thickness	0.615		0.692	0.769	1.230		1.53	0.974	0.807	1.483
Creep calc minimum wall thickness	0.8		0.723	0.966	1.463		1.787	0.974	1.5	2.5
measured minimum wall thickness	0.94	**0.792**	0.74	1.029	0.94*	1.581	**1.779**	1.063	1.624	2.568

*This wall thickness was reported in the PAUT report but is inconsistent with the expected dimensions of the pipe and any conceivable degradation.

5.0 CONDITION AND REMAINING LIFE ASSESSMENT

The intent of the Phase 2 work program is to generate sufficient information to assess the risks to reliability and safety of in-service damage mechanisms not previously identified through operating history and the annual maintenance programs. The assessment is based on the 2014 inspections completed on the boiler components, high energy piping, and feedwater piping of all three units.

The following sections review the inspection results in terms of the impact on remaining life relative to the results from the Level I assessment (Phase 1 of the project), [R-1, R-2]. Recommendations are made where possible. The inspection locations and results are summarised in Table 1 and in the previous NDE summary reports [R-16, R-17]. NDE reports are provided in the reference binders [R-6, R-15]. For the purpose of the remaining life assessments, it is assumed that the unit has been and will continue to be operated within limits (temperatures and pressures) specified in operating procedures.

Risks are assessed in a separate subsection using the models attached in Appendix B.

5.1 Boiler Tubing

5.1.1 History

The Holyrood units have had various problems in the boiler tubing due in part to the fuel quality, seasonal operation, poor process water quality control, and boiler design issues. The following mechanisms are applicable:

Fuel quality:

- Fireside corrosion
- Slagging – mechanical damage to tubing in removing slag

Process Water Quality:

- Hydrogen damage and Inside Diameter (ID) corrosion of waterwall tubing
- Stress corrosion cracking of superheat stainless steel tubes at welds
- FAC in economiser inlet header stub tubes

Design Issues

- Corrosion fatigue in the economiser inlet header stub tubes
- Corrosion fatigue in waterwall tubing
- Premature failure of Dissimilar Metal Welds (low alloy steel to stainless steel) in superheat and reheat tubing.

Seasonal Operation:

- ID corrosion, pitting, and general corrosion

Holyrood has taken a number of steps to address the major historical issues including those listed below. In most cases, the corrective action has involved replacing boiler tubing.

- Changed fuel to high quality to reduce fireside corrosion and slagging.
- Reviewed and upgraded cycle water chemistry to avoid conditions that could result in hydrogen damage or accelerated ID corrosion. Units 1 and 2 were also chemically cleaned to remove ID deposits that are an integral part of the hydrogen or caustic ID corrosion processes.
- Reviewed and upgraded lay-up procedures.
- Implemented an aggressive annual boiler inspection program to monitor damage accumulation. Local modification of attachments was completed to reduce the potential for corrosion fatigue.
- Upgraded stainless steel superheat tube materials at welds to reduce sensitivity to stress corrosion cracking, and avoid potential premature dissimilar metal weld failures.
- Limited investigation to assess creep damage. Tube replacements and material upgrades will also contribute to minimising the impact of creep damage.

5.1.2 Assessment

Due to the extensive annual inspection program and previous work, the previous Level II report identified the major issues to be:

- Corrosion fatigue in waterwalls for all units.
- Corrosion fatigue and FAC in economiser inlet header stub tubes for Units 1 and 2.
- ID corrosion (oxygen pitting) in horizontal sections of tubing.

Previous Level II assessment results for Units 1 and 2 results are in the 2012 and 2013 Inspection results [R-16, R-17]. For Unit 3 the focus in 2014 was to be on corrosion fatigue. Oxygen pitting in boiler tubing is managed under the boiler maintenance contract.

<u>Corrosion Fatigue</u>

There is a history of corrosion fatigue type failures in the waterwalls on Unit 3. The Level 1 analysis was competed in 2009. Recommendations for locations to be inspected by radiography were made based on the analysis of boiler tube failure history from the Level 1 report (2009), and tube failure reports since 2009, and the industry experience (ERPI).

The scope of the present work included review of recent performance. There was one waterwall failure since 2009, but that failure was not related to corrosion fatigue. Given this history and efforts to address the root causes of damage at prior failure locations, it was concluded that the chance of there being advance level damage that could present a safety risk or impair boiler reliability was low. The issue was identified as lower priority compared to other items in scope without a maintenance history, and was removed from the scope of work for the 2014 outage. However, due to nature of past failures, future inspections are recommended. An assessment of the 2014 Unit 3 boiler scope identifying priority locations is provided in the reference binder [R-6].

Circumferential cracking at the economiser inlet header stub tubes can result from corrosion fatigue. The mechanism can be accelerated by FAC. Inspections in this area were carried out in Unit 3. MT inspections found no indications of cracking though FAC has been noted in the Unit 3. Inspections for circumferential cracking in the economizer inlet headers for the Unit 2 tube to header welds was carried out in July of 2014 as part of the maintenance inspections. No indications were found in the sample selected. FAC findings are discussed further in Section 5.3.

<u>Oxygen Pitting</u>

Oxygen pitting is a known issue in boiler tubing at Holyrood in Units 1 and 2, and is being addressed under the maintenance contract. Particular concerns are in the reheat tubing.

5.1.3 Actions

The lack of corrosion fatigue failures or damage in other susceptible locations in Unit 3 suggest further investigations can be treated as a lower priority. Analysis of waterwall corrosion fatigue tube failure history has determined that corrosion fatigue is not a major life limiting or safety concern of the remaining desired life of the Unit 3 boiler, to 2020. Beyond 2020 inspections will be required to investigate the occurrence of the degradation but they are not needed on a regular basis. Corrosion fatigue tube failures can still be a reliability problem and potentially a safety issue but are likely to be isolated events. Future inspections to identify the potential for damage accumulation and likelihood of failure are warranted. Inspections should be done using digital radiography. Radiography of tubes at the vestibule attachment, at the filler bar/casing attachment (inside the windbox), and in east wall floor tubes (north of the previous repair) are potential inspection sites. Any new failures need to be assessed and root cause corrective actions taken.

Wall thinning of boiler tubing is managed through the boiler maintenance program. No pitting was identified in the 2014 inspections. Pitting was reported in the riser tubes of Unit 1 in the 2013 inspection [R-17]. Investigation of the pitting in the horizontal riser tubes by radiography could not rule out the degradation in Unit 2. ID inspection of tubes exhibiting sagging should be considered as part of future outage work but is a low priority. Digital RT can provide the required resolution to identify cracking, or PAUT can be used. This work would be done to investigate evidence of pitting or general corrosion, and to assess the severity of damage. Cycle water chemistry control performance needs to be monitored and action taken if consistent poor performance is identified. If life extension is considered for Units 1 and 2 inspections to determine the extent of pitting will be required.

There are no capital reinvestment requirements at this time.

5.2 Steam Drum

5.2.1 History

The stream drums on all three units are subject to annual inspections of the accessible penetrations on either end of the steam drums. The results suggest the steam drums experience thermal fatigue cracking, or thermally driven corrosion fatigue cracking typical of steam drums on subcritical boilers. Such damage is driven by temperature differentials created by the introduction of relatively cool feedwater during starts [R-19], and is accelerated by corrosion. The corrosive environment causes faster crack growth and/or crack growth at a lower tensile stresses than in dry air. Cracking usually occurs at weld discontinuities due to repeat thermal transients, and can interface with weld defects to develop cracking of extended depth. Most thermal fatigue cracking in steam drums is self-arresting, i.e. cracks grow into low stress region and stop. Removal and repair can result in re-initiation. The cracking is ID surface initiated and is detected by magnetic particle testing (MT).

At Holyrood, accessible penetrations are inspected at either end of the steam drums. The majority of detected cracks in the three units were removed with light grinding. In some cases cracking has been left and is monitored for growth in length. This approach is acceptable under the Nation Board Inspection Code (NBIC) with an engineering assessment. The engineering responsibility has been accepted by the boiler maintenance contractor.

Greater damage has been reported in Units 1 and 2. Very little damage has been found in Unit 3. The riser tube, downcomer and saturated steam nozzles have not been inspected in Units 1 and 2 prior to the condition assessment project. Inspections in 2012 and 2013 identified thermal fatigue cracking at the downcomer nozzles in Units 1 and 2. No damage was found at the riser tube nozzles in Unit 1 in 2013. The same is considered to apply to Unit 2. No damage has been found at the Unit 3 downcomer nozzles.

5.2.2 Assessment

The Unit 3 inspections consisted of MT of the east and west hemi-head ends. MT of the downcomer penetration and all accessible internal welds, including the circumferential seam weld was completed. No indications were found. The steam drum seam weld and riser tube penetrations were not inspected. These areas are considered lower priorities due to the lack of damage at the downcomer, feedwater and other penetrations accessible from the end hemi-heads.

5.2.3 Actions

Based on the Unit 3 findings, history, the number of operating hours, the industry experience from the Phase 1 report, and the fact the major susceptible sites including the downcomers, are accessible from the ends, further inspections beyond the existing annual inspections are considered a lower priority.

There are no capital reinvestment requirements at this time.

5.3 Unit 3 Headers and Boiler Internal Piping

5.3.1 History

The major concerns for headers and boiler internal piping applicable to all units are as follows:

Operating issues

- Thermal fatigue and thermally driven corrosion fatigue on the ID surface of water headers and piping, primarily at tube bore hole ligaments, pipe connections, girth weld stress risers (weld root or counter bore notch) due to feedwater thermal cycling, and neutral axis of bends in upper riser piping and lower feeder piping.
- Thermal fatigue and thermal shock on the ID surface of steam touched headers, in tube borehole ligaments and girth weld stress risers, and at drain hole penetrations due to the flow of condensate or attemperator operational issues where the spray water impacts and cools the opposing wall.
- Creep fatigue in welds, and weld heat affected zone (HAZ) zones, and in parent material operating at temperatures in the creep range and due to thermal cycling, particularly for thick section components.

Design issues

- Creep in welds, weld heat affected zone (HAZ) zones, and in parent material, is a continuous process in components under stress and operating at temperatures in the creep range. Accelerated creep can be a particular issue in seam welded Submerged Arc Weld (SAW) pipe, or in girth welds subject to bending stresses, or where there are localised high temperatures or high stresses. Damage will typically occur on the inside surface, e.g. at tube ligaments. Damage can also initiate mid-wall at susceptible microstructural artefacts or zones such as a double-J weld root, or the fine grained inter-critical zone of the weld HAZ.
- Creep, fatigue and creep fatigue damage on high temperature headers and piping at hanger/structural support weld connections.
- Thermal fatigue due to attemperator component failure.
- Outside Diameter (OD) fatigue of stub tube welds.

Seasonal Operation

- ID corrosion and pitting during lay-up, this can occur in water or steam headers and interconnect piping, including feeder/riser tubes. For steam headers the source of water is condensate.

Annual inspections at Holyrood periodically include accessing the internals of the headers and internal piping. The header access has usually been given for the purpose of removing debris. In some circumstances, the condition of the component internals has been noted.

The economiser inlet header was inspected on Unit 3 in 2002 and was found to be without damage. Similar inspections conducted on Units 1 and 2 in 2002 noted no cracking. However, repeat inspections on Units 1 and 2 in 2010 identified corner cracking at the edge of a number of tube bore holes, indications between bore holes and, on Unit 2, axial scoring between several tubes and in the tee crotch [R-20, R-21]. The worst damage was in the inlet tee region. Linear defects in the ligament area were estimated at 9.5mm (3/8") depth. On Unit 2, it was also determined that the inlet tee was a welded clam-shell construction. Follow-up Phased Array UT (PAUT) assessed the linear indications in the crotch region to have a depth of 1.5mm (0.063"), and other liner indications in the tube 12 region to have no recordable depth. The crotch area indications and those in the tube 12 region were reported as not crack-like. There were no similar indications in the tee crotch or tube 12 region on Unit 1. A re-inspection interval of 3 years was recommended by Alstom [R-16].

A partial (30%) inspection of the Unit 3 Economiser inlet header in 2010 found no evidence of ligament cracking. Wall thickness measurements from the 2013 inspection found a minimum reading of 1.860", above the minimum wall thickness of 1.625".

The Phase 1 report identified a concern over the lack of pipe supports for the economiser link piping on to the steam drum on Unit 3. If this condition represents a support failure, the condition may lead to fatigue cracking.

Upper and lower water wall headers have been inspected at different periods, primarily to remove debris. No cracking or pitting has been observed. Specific inspections of the lower downcomer header and lower water wall headers were requested to confirm that there is no thermal fatigue cracking at the boreholes.

Link piping and superheat attemperators are routinely inspected. Recent internal inspections of the attemperators found no problems. Unit 3 was inspected in 2009. Unit 1 was inspected in 2010. The construction of the link piping on Units 1 and 2 is not known and has not been investigated. There is a possibility that seam welded pipe could be used, particularly on Units 1 and 2. The type of construction and the possibility of subsurface creep damage was identified as an issue to be investigated.

Unit 3 also has a significant amount of interconnect piping between primary and secondary superheaters, and upper and lower reheat sections. Creep is less of a concern due to the combination of seamless construction, low alloy content and temperature. However, the interconnect piping in Unit 3 is susceptible to fatigue or creep fatigue at nozzle welds to the superheat attemperator piping and at the reheat connecting piping. There no inspection history for the connection welds at the interconnect headers.

There is no history available on Unit 3 Secondary Superheater outlet header internal inspections. The reheat outlet header (RH2) has been inspected on Unit 3 in 2003 and 2007. There was no evidence of ligament cracking.

Select secondary superheat outlet and reheat outlet headers stub tube welds are inspected as part of the annual inspection program on all units. Typically, no damage has been found.

5.3.2 Assessment

Economiser Headers and Link Piping

The Unit 3 Economizer outlet link piping support was investigated as part of the 2014 scope. The Unit 3 economiser outlet piping had been identified in the Level 1 assessment as a potential concern for fatigue cracking due to the unsupported length and configuration of the pipe run from the economiser outlet header to the steam drum. The issue was referred to the boiler manufacturer, Babcock and Wilcox Canada. The response is provided in reference [R-6], stated that the applied loads for the given configuration were compatible with the limits provided in the ASME Boiler and Pressure Vessel Code, Section 1 (Power Boilers), and that no support was required. Based on this information, the inspections proposed at the piping to nozzle weld at the steam drum were cancelled.

Internal visual inspections were carried out on all three units in 2014. The Unit 3 inspection found borehole corner cracking that was extending into the ligaments. The cracks occur on the short ligament between the bores, which means they are circumferentially oriented. The ligament cracks occur from platens 15 to 62 and appear to extend into the bore holes. An additional indication was noticed in the root of the circumferential weld of the butt weld near the economizer drain inlet. This indication is considered superficial. The ligament cracks were not inspected to determine size due to the timing of the inspection results availability and the outage schedule. This cracking is assumed to have occurred after the 2010 inspection. Based on the minimum thickness measured in 2013, an assessment conducted by AMEC concluded that there is margin between the observed crack depth and the depth of a bounding case. The bounding case –a scenario with a more extreme flaw than was found- assesses a 360^{o} circumferential crack [R-8]. The assessment found that a 360^{o} flaw of depth 1" can be tolerated. Since the cracks that were actually seen in the economizer are smaller than this, they can also be tolerated.

The borehole corner cracking observed in Unit 3 is common on the inside of economizer inlet headers for power boilers of this design and vintage. They are generally caused by thermal gradients due to the economizer fluid being a different temperature than the metal on start-up. When a thin layer on the inside of the header is colder than the rest of the header, the cold section wants to shrink but it is constrained by the rest of the header –this puts the inside layer into tension. These cracks only grow deeper if the magnitude of the thermal shocks are increased or if the cracks are so large that the internal header pressure grows the crack. Once pressure starts to grow small craze cracks that were created by the thermal stress start to join and align perpendicular to the principal stress field. If the minimum wall thickness is maintained, cracks will not grow from pressure.

Inspections of the Unit 2 and Unit 1 economizer inlet headers was added to the 2014 inspection scope and borehole corner cracking was observed in both units similar to what was seen in 2010. The inlet tee crotch region indications in Unit 2 also appear to be essentially unchanged from the 2010 images. The internal inspection also showed evidence of FAC in Unit 2. Little visual evidence of FAC was seen in Unit 1. UT wall thickness measurements made on the inlet tee of the header and adjacent portions of the inlet piping and header found evidence of wall thinning. The lowest measured wall thickness was 0.932". This thickness was found between boreholes in the tee section, in the area across from the inlet nozzle and immediately below the clamshell seam weld.

The Unit 1 and 2 economiser inlet header inspections had been dropped from the 2012 scope [R-17]. Based on the 2010 inlet header internal inspections the main potentially life limiting issue identified at the time was the ligament cracking, though this sort of damage is common for boilers of this design and vintage. Based on the 2014 results, FAC is the life-limiting degradation mechanism. ASME Section I [R-12] reinforcement calculations were performed to determine the minimum wall thickness and provide guidance for disposition. Assuming a maximum header temperature of 500^{o}F, the calculations provided wall thicknesses of 0.93" (0.94" was used to provide some additional margin) in the Tee horizontal run (header section), and a 1.06" in the inlet nozzle of the tee to meet the Section I code requirements. The calculations also indicated that 0.87" is sufficient for the header wall thickness. Based on this information pad welds were required before the header could be returned to service. Based on the wall thickness after welding, some margin has been restored and the header is suitable for another year or service. Either continued inspection and potentially repair, or replacement of the Tee section will be required to assure adequate remaining life.

The degradation seen in the Unit 1 economizer inlet header is not as severe as was observed in Unit 2. Borehole ligament cracking was observed but these appear not to have changed since the previous inspection in 2010. The expectation is that the header will be suitable for operation for the remainder of the plant life. Per the previous Alstom recommendation, a re-inspection should be carried out in 3 years.

The inlet headers of all three units will need to be routinely inspected to monitor thermal fatigue damage accumulation. The thermocouples installed on the headers need to be used to monitor the header temperatures, particularly for Unit 2 as the minimum wall thickness calculations will be invalidated if the temperature exceeds 500^{o}F. A critical crack size assessment should also be considered to support continued operation of the headers. Such an assessment would also define end of life if the crack growth rates cannot be controlled.

<u>Waterwall Headers, Downcomer and Riser/Feeder Piping</u>

The Unit 3 front lower and front left hand side waterwall headers were inspected visually on the ID. There were no findings of damage on the header or end caps. There were some very small areas of pitting in the front lower waterwall header but this damage is not a concern for the integrity of the header. Otherwise there was no evidence of thermal fatigue in the waterwall headers or lower downcomer header. Based on this evidence and on the inspection history and the results of the 2014 inspections, the headers are not considered to be life limiting.

The Level I assessment noted that the riser tubes between the upper waterwall and the steam drum may experience corrosion fatigue in the neutral axis of bends. PAUT inspections of the apex of the 180° bends in 4 penthouse riser tubes in Unit 3 were performed and no indications were noted. No inspections were conducted on Unit 2 based on a lack of damage found in Unit 1 in 2013.

Radiographic testing was performed on the Unit 2 riser tubes to look for signs of pitting or corrosion fatigue cracking. No indications were noted on the films, however their quality makes discernment of details very difficult. The presence of an active degradation mechanism cannot be ruled out by these results.

Corrosion fatigue in feeder tubes between the downcomers and lower waterwall headers has more recently been reported in industry experience [R-18]. This issue has been treated as a lower priority at Holyrood due to a more aggressive environment promoting corrosion in the riser tubes, and a lack of failures. Inspections to assess susceptibility are warranted due to the potential severity of a blow-out failure.

Superheat Headers, Attemperators and Link Piping

As part of the 2014 inspection scope a macro-etch was performed on the Unit 2 link piping to look for evidence of a seam weld. No HAZ was found therefore the link piping appears to be seamless. This cannot be confirmed with certainty as heat treatments can make the heat affected zone difficult to distinguish. Given that no heat affect zone was found, if the pipe did contain a seam weld, the heat treatment renders it no more susceptible to creep than the parent material. No further work is required.

Inspections of the Unit 3 superheater outlet (main steam) header focussed on the nozzle, circumferential seam, nipples, supports and drain welds. The end cap and header ID were also inspected.

The Unit 3 main steam header was fabricated from SA335-P22, a seamless ferritic steel pipe, with welded nozzles. The absence of a seam weld leaves the welded nozzles and circumferential girth welds as the next most susceptible areas for creep. The MT inspections of the east nozzle and girth welds found no defects. PAUT found no in-service damage to the nozzle girth welds. Investigation of the microstructure of weld/HAZ/parent material showed spherical carbide particles in a ferrite matrix –likely evidence of thermal aging though the original microstructure is not known –but no creep voids or other damage was seen in the areas sampled.

The ID visual inspection was to detect bore hole ligament, weld, and outlet nozzle ID creep and creep fatigue cracking, and thermal fatigue cracking at the drain. There was no visible evidence of cracking detected on the ID. There were areas of exfoliated magnetite scale, particularly around the bore holes. The differences in both the thermal expansion coefficient and elasticity of the magnetite and the P22 case cracks and eventual flaking of the scale; the newly exposed metal will oxidise to form a new magnetite layer. The welds in the header are in good condition; no cracking or other signs of damager were evident.

The main steam header is included in the creep life assessment in Appendix C due to the Life Fraction Expended (LFE) result from the Phase 1 Assessment [R-2]. Using the EPRI methodology, only components with a LFE less than 10% can be excluded from a Level II assessment. The projected LFE for the main steam header under design conditions is 113.8%. The wall thickness measurements for the main steam header were above the minimum wall specification. This means that the creep life calculation completed as part of the Level I assessment remains valid. The LFE under Maximum Continuous Rating (MCR) conditions for the main steam header was 16.5%. Based on the aforementioned information the main steam header will meet the desired end of life.

MT inspections were carried out on the superheat attemperators at the inlet and outlet pipe welds. No defects were found. Creep is not considered a life limiting issue for the attemperator or link piping.

Reheat Headers

In Unit 3 the reheat headers are located in the header vestibule at the south side of the boiler. The inlet reheat header (cold reheat) is not insulated but the hot reheat header is insulated. The reheat attemperators are not in service.

The cold reheat header was inspected internally by boroscope for fatigue, thermal fatigue, thermal shock, and for evidence of corrosion. There was no evidence found of cracking, general corrosion or pitting, though due to access limitations some areas could not be examined closely. MT was performed externally on the ligaments between the perforations, the support welds, a sample of header nipples and on the drain and no indications were found. The cold reheat header does not operate in the creep temperature range, and was therefore not inspected for creep damage.

Based on the inspection results it is concluded there are no life-limiting issues in the cold reheat header. No further inspections are considered necessary on Unit 3 providing there is no significant change in operation. Use of reheat attemperators, or changes in boiler start procedures on any of the three units would constitute significant operating changes. This would warrant follow-up inspection of the cold reheat header, particularly after use of the reheater attemperators.

The hot reheat header inspections on Unit 3 consisted of MT, PAUT and replication of the east outlet nozzle welds and circumferential seam, and MT of the header nipples and drain for macro. UT wall thickness measurements were also taken. MT found a 300^{o} indication at the header drain. This damage is centered towards the east side of the drain and may be a result of stresses placed on the drain due to the thermal expansion of the header during operation. The east header support is not fastened to the support girder allowing for lateral movement of the elongating header, a force which would then act upon the drain pipe. The crack was removed and a new weld applied. The pre-weld MT inspection confirmed that the original defect was removed. The post-weld and post heat treatment MT inspections each confirm the quality of the new weld. The remainder of the hot reheat inspection found no defects. The replication revealed that in the weld HAZ, the header pipe and the header nozzle the microstructure consisted of spherical carbide particles distributed through a ferrite matrix, representing a thermally degraded microstructure typical of this material after more than 130,000 hours of operation. No creep or other damage was found at the locations examined.

The hot reheat header is included in the creep life calculations in Appendix C due to the Life Fraction Expended (LFE) result from the Phase 1 Assessment [R-2]. The reheater outlet header under design conditions has a LFE of 65.8% at projected end of unit life. However under MCR conditions the LFE is only 4.2%. The wall thickness measurements for the hot reheat header are all above the specified minimum, thus the creep life assessment from Phase 1 remains valid. The hot reheat header will to meet the desired end of life, assuming the operating conditions remain the same.

5.3.3 Actions

The Unit 2 economizer inlet header tee may require replacement in one year unless additional pad welds are applied to build up the wall thickness. Yearly inspections would be required until confirmation can be given that the wall thinning rate is sufficiently low to allow for operation until the end of the target life. Replacement of the tee will allow for continued operation without the necessity for re-inspections. The adjacent pipe wall shows enough margin on the minimum wall to reach the end of life without requiring replacement.

Otherwise, the following actions are recommended for the Unit 3 economizer inlet header:

- A review of operating procedures and practices should be conducted to assess start-up practices and the use of low flow control (trickle feed), and thermocouple on the economizer inlet headers for controlling thermal gradients in the economiser inlet header and feedwater piping.
- During the next outage, the economizer should be inspected and the cracks sized to see if there are any changes in the crack lengths or crack direction, and to assess crack depth. Longitudinal cracks are more easily driven by pressure. The cracks can be sized using a caliper if access to cracked ligaments can be provided.

For the Unit 2 economizer inlet header the following actions are recommended.

- The operating temperature of the header must be monitored and must remain below 500^{o}F, or assumptions of the wall thickness calculations will violated and the remaining minimum wall may not be sufficient for the operating conditions. Recent load test information indicated a maximum temperature of 428^{o}F (220^{o}C).
- Review the costs and benefits of the different life management options; re-inspection to confirm wall thinning rates or replacement of the tee section will be required in 2015.
- A critical crack size analysis is recommended for the Units 1, 2 and 3 economiser inlet headers if there is evidence of continuing thermal fatigue crack growth.

Inspections to assess susceptibility of feeder piping in the lower boiler water circuit are warranted due to the potential severity of a blow-out failure. A sample of feeders can be inspected in the neutral access by PAUT. Priority should be given to feeders with high ovality and low radius bends. This inspection should be performed at the next outage when access to the lower water circuit is possible.

No capital investment actions are considered necessary for the superheat or reheat headers or link piping from the results of the 2014 inspection. Wall thickness measurements should be taken again in 3 years time to track wall loss due to high temperature oxidation on the main steam and hot reheat headers.

5.4 Steam Piping

5.4.1 History

The steam piping at Holyrood consists of seamless low alloy CrMo (SA335-P22) materials on the main steam and hot reheat, and seamless carbon steel (SA106-GrB) on the cold reheat. Y fittings are utilised in all three steam piping systems, on all three units.

The reheat attemperators are located in the cold reheat piping but are not used.

Unit 3 has a partially floating support system with rigid rod hangers at the lower Y connections.

The main issues that can affect reliability and safety are grouped as follows:

Operating issues

- Thermal fatigue from condensate events related to operation of drains during starts, or incorrect operation of reheat attemperators (not currently used at Holyrood TGS).
- Pipe distortion or support damage from transient hammer events, causing changes in support system load distributions, or poor drainage, and potentially creep, fatigue, corrosion or a combination of each mechanism.
- Fatigue from high temperature ramp rates and unit starts.
- Accelerated creep from over temperature operation or at stress concentrations created from changes in supports (hangers) and piping load distribution. Bending stresses are particularly detrimental.

Design

- Creep – base degradation due to operation in the creep temperature range.
- Accelerated creep due to manufacturing process, particularly submerged arc weld (SAW) shop welds.
- Accelerated creep in Y fittings on the high temperature systems due to piping loads.
- Inadequate drain capacity or location resulting in possible condensate events leading to thermal fatigue or accelerated creep.
- Incorrect manufacturing heat treatment and tramp material contamination resulting in temper embrittlement.
- Accelerated creep at gamma plugs, instrument ports and thermowells, and at hanger lug connections due to design configuration.

Maintenance

- Lack of, or incorrect maintenance of supports resulting load redistribution and accelerated creep or fatigue in cycling units.
- Lack of, or incorrect maintenance of valves controlling piping drains, or water supply to the attemperators.

Seasonal operation

- General ID corrosion and pitting.

Power process piping design is based on the requirements of the ASME Boiler and Pressure Vessel Code, B31.1, Power Piping. The integrity of the steam piping and damage accumulation is highly dependent on the correct design and operation of the support system. Incorrect behaviour of the support system can result in load redistribution and accelerated creep for piping operating in the creep range and fatigue in low temperature steam piping.

A review of the operating and maintenance history in the Phase 1 project indicted there have been no significant failures or reports of transient events prior to 2013 - hammer or condensate events. Operating data indicates temperatures are within specifications.

Holyrood maintained a piping inspection program from 1989 to 2001. The program consisted of hanger inspection and periodic NDE including replication. It was discontinued after 2001, but available data indicates the support system functioned reasonably well over the period of 1989 to 2001. A preliminary inspection of hangers during the Phase 1 project indicated there were minor issues but no broken hangers, major impact damage, distortion or other key indicators of problems. There are no reports of hanger adjustments other than adjustments associated with the boiler stop valve change on Unit 2. Piping support inspections conducted for the Level II assessment were reported previously [R-17] and identified some irregularities for monitoring on Unit 3 but no immediate actions.

5.4.2 Assessment

The scope of the NDE work on the Unit 3 steam piping discussed below was based on typical industry concerns, results of the original piping analysis indicating forces and moments, and the Phase 1 assessment that the support system had reasonable functionality. Inspection results are contained in the reference binder [R-6].

<u>Cold Reheat</u>

The cold reheat inspections consisted of MT, UT and PAUT at the west cold reheat boiler link and the east cold reheat line drain connection below the turbine. The inspections were to detect fatigue cracking on the OD and ID cracking at either the weld root or counter bore notch. There was no damage found.

A UT B-scan inspection was also conducted on the west cold reheat line 501 (upstream of the lower Y but down stream of the valve V504). The lowest wall thickness measured was 0.587”, above the ASME pressure-base minimum wall calculation of 0.424”. Comparison to the adjacent points suggests that this could be evidence of local pitting but this is still within the 12.5% mill tolerance for fabrication of the pipe. Therefore the pitting is considered minor. Pitting can act as a fatigue initiation site in the presence of a cyclic stress. However, the pipe inspection report did not identify evidence of pipe movement or significant support issues that could indicate a fatigue concern. Therefore, thermal or mechanical fatigue cracking in the cold reheat piping is not considered a life limiting issue. The wall thickness measurements taken on the boiler link and the below the turbine are also above the ASME code minimum.

Base on these results, it is expected that the cold reheat piping on Unit 3 will achieve the desired end of life.

<u>Main Steam</u>

Main steam piping inspection locations on Unit 3 consisted of the east boiler link, the upper Y, the boiler stop valve, the west main stop valve and the west upper turbine terminal connection. The major welds at these locations including pipe to component, instrument connections, gamma plugs, hanger lugs and drains were inspected.

NDE consisted of MT for external macro cracking, PAUT for mid-wall and ID defect detection and replication for incipient creep damage. Thickness measurements were also taken to confirm data used for the remaining life analysis.

The MT inspections at the various locations found no defects. The PAUT inspections identified no subsurface flaws in the welds or HAZ of the inspected welds, indicative of advanced creep damage. The replication found a thermally degraded microstructure consistent with what is typical for ferritic alloy pipe in high temperature service, and had been identified in previous assessments of Units 1 and 2 –spherical carbide particles in a ferrite matrix, with pearlite colonies still evident in some locations.

Circumferential macro-etches were also used to check for the presence of a seam in the main steam piping. This was done at the east boiler link and the west leg of the upper Y. No heat affected zone (indicative of a weld) was located. The main steam piping appears to be seamless. Seams welds can be susceptible to creep damage and their absence removes a potential concern for the remaining life of the piping.

The wall thickness measurements in Section 4.4 indicate the wall thicknesses are greater than the minimum values for the upper turbine terminal and the main stop valve. One of the measurements at the boiler stop valve outlet (13.75" outer diameter) was below the minimum value used in the creep life calculation, but is above the pressure based minimum. A measurement taken during the lamination scan prior to PAUT inspection on the boiler link noted a minimum thickness of 0.94". This is well below the ASME code pressure based minimum of 1.230", and below any fabrication tolerance. Inspection of the same size of pipe at the inlet of the main stop valve found wall thickness ranging from 1.581" to 1.768". Further, the other NDE did not show evidence of damage that would be expected from a low wall thickness. Therefore, the 0.94" wall thickness measurement is suspect and is not used in the condition assessment. Re-inspection is recommended to determine the wall thickness of the pipe at the east boiler link, as soon as is achievable.

The main steam piping is subject to creep. A sample assessment for the main steam piping using the current data (with the exception of the east boiler link measurement) is provided in Appendix C. The main steam upper turbine terminal was added to the creep life assessment to consider all steam piping from the boiler to the turbine body. The main steam turbine terminal, based on the measurements and the design dimensions is now the most limiting creep susceptible component. The results suggest the remaining life of the main steam piping extends beyond the plant desired life. Although repeat wall thickness measurements would be recommended to track possible wall thickness loss due to high temperature corrosion for areas with less margin on the minimum wall thickness, the available margin in minimum wall and the short remaining desired life for the piping make this action a lower priority and needn't be completed unless the plant life is extended.

<u>Hot Reheat</u>

Hot reheat piping inspection locations consisted of boiler and turbine terminal points, Y fittings, and both inlet and outlet samples of the Combined Stop Valves (CSV), associated gamma plug and instrument connections, and hanger lug attachments. The inspections consisted of MT for external macro cracking, PAUT for mid-wall and ID defect detection and replication for incipient creep damage. Thickness measurements were taken to confirm data used for the remaining life analysis.

During removal of the insulation at the west CSV inlet the hanger collar was to have failed. The inspection was expanded to the east CSV inlet where the hanger collar was also found to have failed. The damage and eventual failure of both collars had been hidden by the insulation. Due to the abnormal loading condition presented by these failures, inspections on both CSVs were expanded to the outlet pipe, where the hangers would have been supporting the additional load from CSVs. The collar failure mechanisms was assessed as temper embrittlement. The collar material was confirmed to be consistent with design, but an independent assessment of the size for the replacement collar determined a larger cross section size was required. Otherwise, the root cause of the hanger failure was not assessed. Supporting document are in the reference binder [R-6]. A review of the hanger inspections and potentially removal of insulation at topped out hangers to confirm fitness for service is recommended.

There were no piping defects identified by MT. The hanger lug connection can induce a thermal stress due to the temperature difference between the lug, which is slightly cooled by the surroundings, and the pipe wall, which is heated by the steam. The inspections indicate there is no macro damage at the hanger lug weld. Similarly, no damage was found at any of the boiler link safety valve nozzle, any of the gamma plugs or the girth welds. The CSV inlet and outlet pipes also showed no defects. PAUT, similarly, found no indications of creep damage or other mid-wall or ID in-service defects at any of the inspected locations. Inspection of both inlet and outlet CSV welds on both sides found no indications of damage caused by the hanger failure or otherwise.

The lamination scan at the west turbine terminal, done prior to the PAUT inspection, noted a location that was unusually thin relative to the rest of the pipe. A grid was used to map the wall thickness variation. The mean thickness from the drawings [R-23] is 0.826". The lowest reading taken from the grid was 0.778", the lowest reading was 0.74" found during the lamination scan, but both are above the mill tolerance of 0.722" and the ASME code pressure based minimum wall of 0.692". There was an area below 0.800" and consideration was given to the possibility of solid particle erosion (SPE). SPE had been a noted issue in the Unit 3 turbine. To investigate this further, another wall thickness measurement grid was performed on the second bend upstream of the turbine (a 90^{o} bend). The significant change in direction would make this location susceptible to SPE, however no thinned areas were noted; the lowest recorded thickness was 0.922". Since all locations were above the ASME minimum wall thickness, no intervention was necessary. The wall thickness variation at the turbine terminal is likely a manufacturing defect. A review of manufacturing and installation records could provide information to determine if the thinning is in-service damage or an original defect. Given thet current state and remaining life, this action is considered a low priority.

Microstructure replications were taken at a number of locations on the hot reheat piping. The replication identified a thermally degraded microstructure consistent with other locations on Unit 3 steam pipes and results from Units 1 and 2. No evidence of creep void formation was found in the weld, HAZ or parent material. There were no indications to suggest degraded material properties that would alter the remaining life assessment. Circumferential macro-etches were also used to check for the presence of a seam in the hot reheat piping. This was done at the east boiler link and the west CSV inlet. No heat affected zone (indicative of a weld) was located. Seams welds can be susceptible to creep damage and their absence removes a potential concern for the remaining life of the piping.

One wall thickness measurement was found to be marginally below the minimum value used in the Level I creep life assessment for the hot reheat piping. The measured value was incorporated into the assessment but had little effect on the LFE. The results, given in Appendix C, suggest the remaining life of the hot reheat piping extends beyond the desired life. Although repeat wall thickness measurements would be recommended to track possible wall thickness loss due to high temperature corrosion for areas with less margin on the minimum wall thickness, the available margin in minimum wall and the short remaining desired life for the piping make this action a lower priority.

5.4.3 Actions

Based on the available inspection data, the high-energy steam piping will reach the desired end of life and there are no issues to be addressed on Unit 3. Specific recommendations are identified below based on the 2014 inspections.

- Review and assess pipe support collars in the hot reheat and main steam piping systems at locations with topped out hangers for possible failure.
- Re-inspect the piping at the main steam east boiler link to determine the wall thickness.

5.5 Feedwater Piping

5.5.1 History

The feed water piping consists of condensate and feedwater piping, (High Pressure (HP) and Low Pressure (LP) feedwater), low flow piping, superheat attemperator piping boiler feed pump recirculation piping, and feed water heater vent and drain piping. The commonality is exposure to single phase process water, or two phase combination of condensate and steam.

The primary failure and life degradation concerns are as follows:

Operations

- Thermal fatigue and thermally driven corrosion fatigue due to high start-up feed water feed practice.
- Fatigue and mechanical damage due to hammer transients.

Design

- Flow accelerated corrosion (FAC) due to a combination of water chemistry, system metallurgy (materials of construction), process conditions (temperature), and pipe geometric factors.
- Erosion in elbows and pipe downstream of valves due to two phase flow.

Maintenance

- Incorrect or lack of maintenance of flow control valves resulting in thermal fatigue (same concerns applies to economizer inlet header).

Seasonal Operation

- General corrosion and pitting due to incorrect lay-up of piping.

Holyrood process water chemistry is classified as low oxygen, All Volatile Treatment – Reducing (AVT-R), which supports FAC. Chemical injection is at the condensate extraction pumps which will make the low pressure feed water piping susceptible to FAC in addition the HP pressure feed water piping. A review of the water treatment practices subsequent to the hydrogen damage events in the Unit 2 waterwall tubing did not address FAC susceptibility.

Holyrood has a basic wall thinning monitoring program consisting of periodic wall thickness measurements at designated locations, usually elbows. Point measurements are taken at the same location and the difference is monitored over time.

There are no reports of water hammer events and inspections during the Phase 1 project did not identify evidence of significant mechanical damage (distorted piping or damaged pipe insulation).

Thermal fatigue, or thermally driven corrosion fatigue has not been monitored. Reports of reliability issues with the low feedwater flow control components and recent inspections of economiser inlet headers suggest conditions that could lead to thermal fatigue cracking in the feed water piping, typically in welds at elbows or in the thick section valves, isolation valves and Non-Return Valves (NRVs), may occur. However, repairs to valves on Units 1 and 2 and inspection the isolating value on Unit 3 indicate thermal fatigue in the feedwater piping and components is not a life limiting issue.

There are no reports of corrosion during lay-up being an integrity issue for feedwater piping. Lay-up guidelines have also been recently reviewed and updated. This will reduce the chance of corrosion when implemented.

5.5.2 Assessment

The Holyrood wall thinning monitoring program does not constitute a FAC control program. FAC will be found in elbows, but the most significant effects are in the piping up and down stream of the fittings –fittings being the cast or wrought component, which have different manufacturing tolerances than the piping. The fittings can tolerate the thinning caused by directional change, and leading to turbulent flow, better than the adjacent piping. FAC also occurs over an area of pipe, and may not be fully realised through single point measurements. Industry practice [R-24] includes monitoring, typically consisting of mapping wall thickness around the circumference of the pipe 2 to 3 pipe diameters on either side of the fittings.

The planned FAC inspections were to identify the existence of FAC, and severity of the damage. Locations were selected based on industry and Holyrood operating experience, and represented areas of greatest consequence in the event of failure.

FAC inspections were completed in the five recommended locations on the feedwater piping in Unit 3 and one location on Unit 2. The Unit 3 inspection locations were the Pump 1 Discharge Piping, the Full Flow Tee downstream of high pressure feedwater heater No. 6, the superheat attemperator station, the low feedwater flow connection to the main feedwater supply, and the elbow upstream of economizer inlet. The inspection location on Unit 2 was the Tee after the No. 5 HP heater.

There was no inspection on the low pressure (LP) piping. Based on results from Unit 2 indicating no evidence of FAC, the LP piping was not considered a priority. The boiler feed pump recirculation piping had also been replaced and as a result was not inspected. Inspection of the Unit 2 No. 5 HP heater discharge tee also found some evidence of FAC, but it is not a concern within the expected life of the unit.

FAC was evident in several locations but does not present an immediate concern due to large margins on minimum wall thickness. The second bend downstream of the Unit 3 No. 6 heater had one point with a wall thickness equal to the ASME code minimum. The profile of the wall thickness was not typical for FAC degradation. The low point may have existed since fabrication. A pad weld was applied to the build up the thickness in this area. Based on the thickness measurements taken after application of the pad weld, the calculated re-inspection time is 5 years but re-inspection of the pad weld is recommended in 3 years based on industry practice. Also at the No.6 feedwater heater discharge tee, damage was identified in the by-pass side of the tee. This is unusual in that the by-pass should not see significant operating time. The by-pass would be used if the heater was valved out for an extended period. The operating history needs to be clarified by Newfoundland and Labrador Hydro, as other locations in the by-pass could accumulate damage under such circumstances.

A low remaining life was also found at the west BF Pump discharge at the inlet of the isolation valve. This is likely related to the counterbore but represents a location that may be below minimum wall requirements before end of life. Re-inspection in one year and possible pad welding is recommended for this location.

Portions of the Unit 3 superheat attemperator station were replaced in 2010 according to the drawing [R-25]. Based on the locations identified in the drawing the as new, wear rates were adjusted to consider the actual time in operation of only 4 years. The result is that the bend upstream (north) of the block valve (1st valve in the attemperator station) should be re-inspected in 2 years. The band method used to calculate the wear rate for FAC cannot distinguish between thickness variations from the manufacture of the component or actual wall loss due to FAC. The recommendation is to re-inspect and determine and more accurate thinning rate to calculate the remaining life. Repeating the analysis will determine if remediation is necessary before the targeted end of life.

It is evident from the limited inspections that FAC damage is accumulating in the HP feedwater piping and associated components on all Holyrood units. The remaining sites will remain in good condition for at least 4 years of operation. However, additional inspections and or an engineering susceptibility analysis would be beneficial to identify potential reliability and safety concerns in other susceptible systems and components: deaerator and feedwater heater shells, feedwater heater drain and vent piping and boiler feed pump recirculation lines. Should plant life be extended beyond 4 years re-inspections for several components will be required.

5.5.3 Actions

As described, FAC is an active mechanism in the Holyrood HP feedwater piping and related subsystems. The work completed indicates there is damage accumulation but that a major failure in a high pressure component is unlikely over the remaining high utilisation operating period, to 2018. At the same time, it is possible that failures will occur in lower pressure or small bore components that have not been investigated. Examples include feedwater shells, drain and vent piping. Also, the boiler feed pump recirculation lines on Units 1 and 2 have not been inspected.

If operation beyond 2018 is required, then locations with a calculated re-inspection time of less than 5 years will require inspection (see Appendix C).

It is recommended that:

- An FAC engineering assessment be conducted to provide greater targeting for inspections and to consider options to correct or minimise the impacts of FAC. This would benefit all three units.
- On Unit 3 re-inspection be completed at the following locations:
  - Attemperator station inlet bend in 2 years,
  - The bends downstream of the No. 6 feedwater heater in 3 years,
  - The elbow to valve and valve discharge on the west BFP discharge be re-inspected within 2 years,
  - A review of the No.6 feedwater heater by-pass need to be conducted. If there was extended operation with the by-pass in service, additional sites in the by-pass line such, as the tee upstream of the Heater No.6 inlet and the bends in line 521, may have accumulated FAC damage.

Additional recommendations are provided in the 2012/13 report [R-17]

5.6 Unit 3 Generator

5.6.1 History

- Following is a summary of the major work done and findings on the Unit 3 generator.
  - Last Major Inspection 2007
  - Next Major Overhaul/Inspection 2016

2001 Overhaul

- New 18Mn/18Cr retaining rings were installed on the rotor
- Broken packing block was replaced
- Field windings reported to be in good condition – no serious defects found
- Coupling bolt hole #11 was badly scored - honed smooth and an oversize bolt installed
- Hydrogen coolers were water-tested and found satisfactory - new gaskets were installed
- Collector End upper and lower seal insulation frames replaced
- Hydrogen Seals cleaned, segments lapped, and clearances adjusted
- Score marks lapped out of the seal oil vacuum pump - pump seals replaced

2007 Overhaul

- Full stator winding re-wedge using similar wedges to those originally supplied by Hitachi (not top ripple springs)
- A damaged series connection and a damaged phase joint were repaired and cured
- Turbine generator shaft was realigned to minimize the bending stress at the coupling
- Stator frame realigned with the new T-G shaft position
- Some rotor slot end wedges had migrated and were moved back into position and staked
- Field winding measurements were taken but no repairs necessary
- Hydrogen Seals cleaned, segments lapped, and clearances adjusted
- Bearing journals cleaned and strap lapped
- Water-pressure test done on hydrogen coolers – no leaks
- New bearings and seals were installed in the seal oil vacuum pump

2013 Testing

- During the annual Unit 3 generator maintenance outage testing was carried out on the generator. Alstom, the station's existing turbine and generator service provider, conducted basic electrical testing of the stator and rotor including ELCID of the stator core, and a stator end winding bump test.

The stator and rotor still have the original copper windings and insulation and have not been rewound in the 34 years of operation to date. The insulation class of the stator and rotor are Class B (130^{o}C). Design life for this type of generator is 25 to 30 years and therefore this machine has exceeded its original design life. The overall condition of the generator is considered good for its age.

Based on the information available up to 2013 the recommendation was that the generator should be overhauled in 2016, as is planned. Rewind of the generator stator and rotor will be required to achieve reliable synchronous condenser operation to 2041 and it is recommended that this work be executed in the next two major generator outages; either in 2016 or 2022, or a split of work between the two. Rewinds should not be postponed beyond 2022. Planning should commence several years in advance of the overhaul activities and inspections.

5.6.2 Assessment

Below is an assessment of the possible life-limiting mechanisms based on operational and design issues for the Unit 3 generator.

- Stator Core: satisfactory, based on ELCID test results – core iron needs to be re-validated by testing prior to any stator rewind effort
- Stator Windings: satisfactory up to 2007 - stator bars will require retightening at some point and ground-wall insulation issues expected to occur as time goes on
- Rotor forging: no NDE checks since 2001 – forging will require full NDE re-validation prior to any rewind effort
- Rotor winding: satisfactory, per CGE report 2001 – no major issues at the present time
- Auxiliaries: H2 coolers, H2 seals, bearings, and excitation components will require major inspection and maintenance to achieve extended life. This should be done during the next major outage when the component are accessible.

Generally, there are no immediate life-limiting issues for the very near future. Long term issues are simply age and wear-out related.

The Unit 3 Generator underwent a planned overhaul in 2014. Inspections and testing were carried out at this time as well. The rotor was not removed and all testing was done with the rotor in-situ. There were four (4) specific tests done on the rotor, as follows:

1) Shaft Voltage Measurements (SV)
2) Sweep Frequency Response Analysis Measurements (SFRA)
3) Repetitive Surge Oscillograph Measurements (RSO)
4) Rotor Winding Insulation Resistance Measurements (IR)

A review of the results was provided by an AMEC subject matter expert and a response was provided to NL Hydro [R-26]. From the review it was noted that the shaft voltage measurements are considered low. The spiking is most likely due to "excitation spikes" from the static exciter thyristors. The Sweep Frequency Response Analysis Measurements do not reveal anything significant but can be used as a fingerprint for future trending to identify any insulation issues that may occur. Repetitive Surge Oscillograph Measurements distinctly show at least one (1) shorted turn in one location but does not present an immediate concern since no vibration issue was reported. Rotor Winding Insulation Resistance (IR) Measurements do not indicate anything significant and are acceptable.

Overall, there is no immediate concern with the rotor ground or inter-turn insulation, based on the reviewed information.

5.6.3 Actions

Per the Alstom report [R-27], installing an on-line flux probe is recommended to allow trending to determine if the short noted in the Repetitive Surge Oscillograph Measurements progresses in magnitude or if more shorts appear. If there is a change in shorted turn activity or rotor lateral vibration increases, then more frequent readings should be taken to determine the rate at which the deterioration is occurring. A rotor rewind would be the only way to correct fully this situation.

A 10 minute IR measurement is recommended so that a Polarization Index reading can be obtained. This is minimal effort and would allow further determination of the rotor ground insulation condition.

5.7 Unit 1 Generator

5.7.1 History

The Unit 1 generator is rated at 194,445 KVA, hydrogen-cooled, supplied by Canadian General Electric, Peterborough. 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 and are indirectly cooled by hydrogen. The hydrogen is circulated throughout the generator in a closed system, at 310 kPa (45 psi) pressure, by an axial fan mounted on each end of the rotor. 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 the hydrogen from escaping around the rotating shaft. 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.

5.7.2 Assessment

The AMEC assessment is in agreement with the Alstom report and assessment of the Holyrood Unit 1 generator. The generator shows aging signs typical for this type of GE generator. The endwinding appears to be loose, and is likely the cause of the paint cracks and general grease contamination, based on the information provided. The generator is operable, as Alstom states, but as with all older GE generators, regular inspections are required.

The electrical testing results are all acceptable. A pole-to-pole volt-drop to see if any shorted turns are present is advised. The electrical testing done on the rotor was only suited for checking grounds to the rotor forging. Despite the unavailability of the RSO a pole-to-pole test could have been done with the rotor still installed. From the test results and what can be seen, the rotor winding insulation is still in reasonably good condition for its age.

The machine, both stator and rotor have a medium to high probability of making it to 2020 will only the normal maintenance. Beyond that, major refurbishments such as rewinds, need to be considered.

5.7.3 Actions

The endwindings, wedges and any other loose components should be re-tightened as required. Another inspection and a bump test are recommended for this generator. A bump test at both ends of the generator was recommended prior to closing the generator; it can be done with the rotor in place. At the next major outage a thorough cleaning, some additional EW blocking, and try to shift the natural frequency up. The expectation is that the results of a current bump test would find the frequency under 130 Hz and that is too close to the 120 Hz twice per rev.

5.8 Raw Water Line

The High density polyethylene (HDPE) section of pipe was installed to replace asbestos-cement (AC) pipe. This section is a 450mm (18") diameter line that runs from Pump house Unit No. 3 and ties into the 400mm (16") diameter AC pipe.

HDPE pipe will not corrode, support biological growth, is inert to salt water and has a service life of 50-100 years.

AC pipe has an estimated life span of 70 years depending on pipe condition and working environment. AC pipe gradually corrodes which leads to a reduction in the effective cross-section, which results in pipe softening and loss of mechanical strength. As the pipe ages, the number of AC pipe failures increases with time. Factors affecting AC pipe failure propensity, include

- Pipe age
- Pipe diameter
- Pipe class
- Pipe manufacturer
- Internal/external water chemistry
- Internal water pressure
- Soil physical and chemical properties
- Groundwater table elevation
- Overburden
- Climate

The installation date stated on the supplied drawing was 1969.

5.8.1 Assessment

The weakest section of the raw water line is the original AC pipe. Acoustic testing on part of the pipe in 2014 identified one potential leak. The other readings from location 805 to 940 were omitted due to the poor testing conditions being expected of causing the high readings.

The AC has an expected life of 70 years and has been in service for 45 years. Utilizing the pipeline to 2041 will exceed the expected life of the sections of AC pipe by 2 years. Two strategies are available to maintain the required performance over the life of the raw water system. In the first case, the pipe can be replaced. In the second case the pipe can be inspected and repaired. Given the criticality of the system, the likelihood of performance degradation and escalating cost of inspection and repair, it is expected the replacement option would be preferred.

5.8.2 Actions

It is recommended that:

- A cost benefit analysis be conducted to determine if replacement or inspection and repair is the most cost effective option.
- The two areas identified in the AGL report be retested to confirm the status of the pipeline in those areas.

5.9 Powerhouse Siding

5.9.1 History

The plant building is approximately 45 years old. The panels are secured to the horizontal structural members of the powerhouse wall's. The siding was finished with an asbestos-containing coating.

During the winter of 2013/2014 a substantial section of steel siding approximately 2.1m by 5.5m was blown off the building. The section came from the south elevation.

5.9.2 Assessment

Visual examination of the wall system revealed:

- Exterior steel siding varies in condition from small areas of non-existent to extremely rusty to solid.
- The siding's original paint finish, Galbestos, varies in condition from flaky to good.
- Previously replaced siding is in good condition except in one location where it has sustained impact damage.
- The interior steel liner sheet appears to be in good condition.
- The notched Z bars, from the few that were visible, appear to be in good condition.
- Most of the deteriorated siding appears along the Building's South elevation.

- Deteriorated siding appears mostly at the bottom of walls and over openings in the wall system, such as at doors, windows, louvers and the like.
- The original exterior siding profile is 38 mm deep and is of a common profile.
- Previous repairs to the original siding appear to have been made by cutting away the affected area and providing new material which would span from the base of the affected wall to the nearest notched Z bar or horizontal structural member.
- The perimeter of the infill was trimmed using standard trim or drip pieces, which is a common approach to this type of work.

AMEC assessed the condition of the siding, made recommendations on the repairs required to the siding, the priority for those repairs and the estimated cost of the repairs.

5.9.3 Actions

A report issued to Newfoundland and Labrador Hydro outlined items that AMEC felt posed an immediate safety risk or had a high probability of causing damage to the plants infrastructure [R-6]. The recommendations included:

- Replacing a fan motor cover.
- Making repairs to a steel fan shroud.
- Making repairs to four guy wires attached to the above shroud.
- Making repairs to the shroud soffit dangling from the underside of the above shroud.
- Removing pieces of the above shroud lying on the roof.
- Removing a piece of sheet metal lying on the roof.

The recommendation made for the replacement of existing rusted siding will follow the repair methods previously used.

Replacement siding will span between horizontal structural steel members. Replacement of siding in lengths, which would not span between structural members is not recommended.

The report in the reference binder outlines in detail the recommendations made by AMEC. AMEC recommended work be done to specific areas on the South of the plant, to the East and West of the plant and to the North of the plant.

Priority 1 – South Elevation

The South elevation is the side of the plant facing the switchyard. There are exits/entrances to the plant on this side of the plant as well as an overhead door. Therefore any siding that falls from this side of the building has the highest potential to cause major damage to the plant. Injuries to personnel are also possible.

Priority 2 – East and West Elevation

The main entrance to the plant offices is located on the West elevation as well as other entrances/exits. The East elevation also has entrances/exits. There is also the potential that siding that falls from the East or West elevations could damage the switchyard located on the South side of the plant. Any siding that falls from either the East or West elevations has the potential to injure personnel and potentially damage the plant.

Priority 3 – North Elevation

A siding blow off that occurs on this side of the plant is unlikely to cause damage to the plant. However, there are entrances/exits to the plant on this elevation and there is the potential for injury to personnel.

AMEC recommended a budget cost of $155/m2 to $200/ m2 for the replacement of the siding. The total estimated cost for the siding replacement recommended by AMEC is $1,105,000.

- The estimated cost for the South elevation is $435,000.
- The estimated cost for both the East and West elevation is $450,000.
- The estimated cost for the North elevation is $220,000.

6.0 CONDITION AND RISK SUMMARY

Table 4 summarizes component level condition and technical and safety risk for the components addressed in the current report for Holyrood TGS Units 1, 2 and 3. Table 4 addresses each component by component type, where life issues and risk would apply for areas inspected in 2014.

Where identified, asset designation is provided based on the asset register identified in the Phase 1 final report [R-1].

Asset Register

Asset Class:	BU 1296 Assets Generation
	BU 1297 Assets Commons
	BU 1325 Assets Holyrood Switchyard
Asset Level 2	8193 #2 (Unit 3), 7635 #2 (Unit 2), 6690 #1 (Unit 1)
	Buildings and Site – 7255
	Unit 1 Generator – 6691
	Unit 3 Generator – 8193
Asset Level 3:	Buildings – 272255
	Drainage – 6781 #1, 7699 #2, 8257 #3
	Unit 1 Generator – 6696
	Unit 3 Generator – 8194

Asset number beyond Level 3 is provided in the table.

Based on the present information the economizer inlet headers present potential end-of-life issues or capital requirements in order for the boiler to reach the desired end of life.

Remaining life in Table 4 is identified as 1 year for both Unit 2 and Unit 3. Remaining life for Unit 1 is identified as 10 years in order to bound the present operating plan identified in Section 2.

These conclusions are based on the assumption that design parameters are maintained, and correct operating procedures are followed.

For each risk ranking, a description of the expected failure event and mitigating actions are provided. The actions are intended to reflect the component level recommendations in Section 7.

7.0 RECOMMENDATIONS

The original 2012 Phase 2 Condition Assessment and Life Extension Study was to focus on boiler and high-energy piping issues on Units 1, 2, and 3. The Unit 2 and Unit 1 investigations were completed in 2012 and 2013 [R-11, R-12]. The Unit 3 investigations were conducted in May of 2014. This is considered the final effort for the Phase 2 study.

Completed versus planned NDE scope is identified in Appendix A. Additional inspections were conducted on Unit 3 to investigate the impact of the Inlet CSV hanger collar failures, to investigate the internal degradation of the Units 1 and 2 economizer inlet headers, and other targeted areas in Unit 2; specifically the superheat cross-over piping, risers, and feedwater FAC.

Overall, the components evaluated are in good condition. The condition of the Holyrood plant components is similar to other units of similar age. Holyrood has gaps is in the management programs for hangers and FAC. However, upon discovery of an issue, station personnel are quick to address the issue. There are potential life-limiting issues for the economizer inlet headers in Units 2 and 3. Capital expenditure may be required to achieve the desired operating life (2020). The building siding is also at end of life and capital reinvestment will be required to achieve desired life (2041). Monitoring and repair of the siding is required to manage the high safety risk. There are also issues that will need to be managed in order to achieve the desired safety and reliability performance. These issues include thermal fatigue of the economizer inlet headers, potential corrosion fatigue and hanger abnormalities. FAC in the HP feedwater piping and auxiliary systems is also an issue on all three units. It is not considered life limiting to 2020 but reliability and potentially safety issues may be encountered. It must be noted that the planned inspections were not completed for all identified components but the life assessment scope of work is essentially complete. The inspections not completed are dispositioned as “Not Required (NR)” in Appendix A.

The recommendations below are based on results of the assessment in Section 5 and the risk assessment in Section 6, with a focus on Unit 3. Additional recommendations for Units 1 and 2 are provided in the 2013 report [R-12] Actions are recommended at the earliest opportunity unless stated otherwise below.

In addition to the life assessment, other specific locations are listed below as follow-up to the damage identified in 2014 and previous inspections.

If operation beyond 2020 is forecast, the recommendations need to be reconsidered.

7.1 Boilers

The following recommendations are part of the life assessment scope:

1. Complete waterwall inspections for corrosion fatigue on Unit 3 within 2 years. Digital RT is recommended to identify cracking.
2. Inspections in all three units of the feeder tubes between the downcomers and lower waterwall headers to assess susceptibility of corrosion fatigue are warranted within two years due to the potential severity of a blow-out failure. A sample of feeders can be inspected in the neutral access using Phased Array Ultrasonic Testing (PAUT). Priority should be given to feeders with high ovality and low radius

bends. This inspection should be performed at the next outage when access to the lower water circuit is possible.

3. A review of lay-up practices for all three units is recommended within 1 year to ensure measures to limit corrosion and pitting of boiler and piping components are being effectively implemented.

The following recommendations should be completed as follow-up to the damage identified during inspections in the economiser inlet headers on all three units:

1. For the Unit 3 economizer inlet header review of the operating conditions, start-up practices and thermocouple information before the end of 2014 is required to reduce the potential for thermal shock and further advancement of the internal diameter (ID) cracking is reduced. Boiler transients, start-up data and condition of feedwater control equipment should be included in the review. Thermocouple information and start-up data should also be reviewed for Units 1 and 2.
2. Sizing of the cracks in the Unit 3 economizer inlet header should be done in the next outage (within 1 year). If there is crack growth or the crack size exceeds the critical size limit then further assessment will be required.
3. The operating temperature of the Unit 2 economizer inlet header must be monitored to remain below 500^{o}F, or the minimum wall thickness may not be sufficient for the operating conditions. Recent load test information indicated a maximum temperature of 428^{o}F (220^{o}C).
4. Re-inspection of the Unit 2 header is required within one year to confirm wall thinning rates, or replacement of the tee section will be required in 2015. If the tee section is replaced, no repeat UT grid will be required.
5. Based on the Alstom recommendation, re-inspection at 3-year intervals for crack growth on the Unit 1 and 2 economizer inlet headers is advised. If there is evidence of crack growth, an integrity assessment is recommended (one assessment covering both units). An integrity assessment will define critical crack size, growth rate and end of life, and will provide a basis for continued operation without repair and define end of life.

7.2 Steam Piping

The following recommendations should be completed as follow-up to the damage identified during inspections:

1. Wall thickness measurements are required at the next opportunity on the 10.75" pipe connected to the Unit 3 main steam east boiler link to disposition the 0.94" measurement reported from the PAUT inspection.

7.3 Feedwater Piping

A FAC susceptibility analysis and implementation of management program consistent with industry practice is recommended to assess the full scope of FAC in the Holyrood units. This engineering assessment would be beneficial to target susceptible locations that have not been explored which may have accumulated FAC damage over the life of the plant.

These locations include boiler feed pump (BFP) recirculation lines up-stream of the pressure breakdown orifices, superheat attemperator water supply piping, HP feedwater double elbows and HP heater drains, shells and vents. Specific actions for Unit 3 indentified during the inspections are:

1. Inspection of the west BFP discharge piping at the isolation valve inlet is required within 1 year. Inspection of the valve outlet piping is recommended at the same time.
2. Monitoring of wall loss due to FAC is required on the feedwater system. Inspection of the inlet bend of the superheat attemperator station is required in 2 years.
3. Inspection of the repair above the No. 6 HP feedwater heater is recommended in 3 years.
4. Use of the HP Feedwater Heater 6 by-pass needs to be investigated within 1 year through a review of station operating records. If the by-pass piping is used regularly, FAC grid inspections of additional sites in the by-pass line, such as the tee upstream of the Heater No.6 inlet and the bends in line 521, are recommended.

7.4 Hangers and Supports

The Unit 3 reheat inlet combined stop valve (CSV) hanger collar failures demonstrate need for a hanger program. A hanger inspection and high-energy steam piping management program is recommended to monitor damage accumulation in the piping and condition of the supports to manage steam piping performance over the desired remaining life of all three units. Inspections should be carried out every two years and the results compared. Specific actions are:

1. Review and corrective action is recommended to address minor mechanical issues and to balance loads on the trapeze hangers.
2. The Unit 3 CSV hangers need to be inspected in the hot condition to confirm correct operation (not topped or bottomed out).
3. Monitor pipe hangers in the topped or bottomed out condition, or showing no movement. Conditions where multiple pipe hangers in a system are either topped or bottomed out should be considered for analysis to determine impact on the system piping stresses and load distribution, and on the other pipe hangers. In addition, manufacturer specifications for the pipe hanger should be consulted. Further details are provided in the 2012 and 2013 inspection reports. Topped out hangers may be indicative of a failure as was seen at the Unit 3 CSV inlet.
4. Review and assess pipe support collars in the hot reheat and main steam piping systems at locations with topped out hangers for possible failure.
5. Repairs are recommended at the Unit 1 Hot Reheat supports HR15 and HR17; concrete and mounting plate repairs at the base of the stanchions and possible replacement of the stanchion.

Related to the Unit 3 Hot Reheat hanger collar failure, a review of previous inspection results is recommended, and inspection of hangers that are topped out (unloaded). The

Unit 3 event may be an isolated occurrence related to the high load at that location, and an undersized collar, or there may be additional hangers susceptible to the same problem.

7.5 Generators

The assessment of for Unit 3 generator recommends:

1. Installation of an on-line flux probe is recommended to allow trending to determine if the short noted in the inspection progresses in magnitude or if more shorts appear.
2. A 10 minute IR measurement is recommended so that a Polarization Index reading can be obtained.

The assessment of for Unit 1 generator recommends:

3. The endwindings, wedges and any other loose components should be re-tightened as required.
4. Another inspection and a bump test are recommended for this generator; it can be done with the rotor in place. This test should be conducted at the next outage where the generator is opened, presumed to be 2016.
5. At the next major outage a thorough cleaning, some additional EW blocking, and a upward shift of the natural frequency are recommended.

7.6 Civil Structures

The assessment of the raw water line recommends:

1. A cost benefit analysis should be conducted to determine if replacement or inspection and repair is the most cost effective option.
2. The two areas identified in the AGL report be retested to confirm the status of the pipeline in those areas.

The assessment of the powerhouse siding recommends work on specific areas on all sides of the plant. Recommendations for the inspection and repair of powerhouse siding in order of priority are: the South Elevation, East and West Elevations, North Elevation. The siding is at the end of its life but is required until 2041. Capital reinvestment will be required in the near term. Since the damage will accumulate and at a higher rate as time passes, the repairs should be initiated in 2015. Monitoring and repair is recommended to manage the high safety risk from falling siding.

Table 4 Condition Summary and Risk Assessment

Asset # 3	Asset # 4	Asset # 5	Description	Component	Major Issues	Remaining Life Years [1] (Insufficient Info - Inspection Required)	Remaining Life Comments	TECHNO-ECO RISK ASSESSMENT MODEL			SAFETY RISK ASSESSMENT MODEL			Possible Failure Event	Mitigation
								Likeli-hood	Conse-quence	Risk Level	Likeli-hood	Conse-quence	Safety Risk		
8337 - UNIT 3 BOILER STRUCTURE															
8337			Waterwall	Lower Waterwall Header	Thermal fatigue cracking, Corrosion-fatigue cracking. Corrosion	10	No apparent life limiting issue.	2	B	Low	1	B	Low	Ligament cracking and weld cracking.	Proper start-up procedures to reduce thermal transients. Proper lay-up practice to prevent pitting.
8337			Waterwall	Tubing	Thermal fatigue cracking, Corrosion-fatigue cracking. Corrosion	10	No apparent life limiting issue.	3	B	Med	3	B	Med	Corrosion fatigue cracking.	Proper start-up procedures to reduce thermal transients. Proper lay-up practice to prevent pitting.
8337			Downcomer	Downcomer Header	Thermal fatigue cracking, Corrosion-fatigue cracking. Corrosion	10	No apparent life limiting issue.	1	B	Low	1	B	Low	Thermal/Mechanical Fatigue Cracking at the header support locations	Proper start-up procedures to reduce thermal transients. Proper lay-up practice to prevent pitting.
8337			Hanger	Steam-cooled Roof Hanger lug attachments.	fatigue	10	No apparent life limiting issue.	1	B	Low	1	B	Low	Hanger lug failure. Section unsupported, other hangers overloaded.	Visually inspect hangers and attachments during outages for abnormalities.
8339 - UNIT 3 BOILER F.W. & SAT'D STEAM SYSTEM															
8339	**8340**		#3 BOILER ECONOMIZER	Inlet Header	Thermal/Mechanical Fatigue Cracking, Corrosion-Fatigue Cracking, Corrosion, FAC.	1	Sizing of cross ligament cracking, wall thickness measurements, and critical crack size assessment necessary. Monitoring of header temperature and start-up practices required.	3	B	Med	2	B	Low	Ligament cracking, tube stub thinning/cracking, weld cracking.	Critical size assessment. Monitoring of header temperature and start-up practices required.
8339	**8344**		3 BOILER STEAM DRUM	Penetration welds and seam welds	Thermal fatigue cracking, Corrosion-fatigue cracking	10	No apparent life limiting issue.	1	D	Med	1	C	Low	Ligament cracking. Weld cracking.	Inspect accessible welds during regular outages.
8359 - Unit 3 BOILER SUPERHEATER & REHEAT ASSEMBLY															
8359	8366		SECONDARY SUPERHEATER	Superheater outlet Header	Creep and thermal fatigue	10	No apparent life limiting issue.	1	D	Med	1	D	Med	Creep and thermal fatigue cracking.	Maintain good operating practices to prevent temperature or pressure transients.
8359	8362		SUPERHEATER ATTEMPERATOR	Inlet and outlet piping welds	creep cracking	10	No apparent life limiting issue.	1	C	Low	1	C	Med	Creep and thermal fatigue cracking.	Ensure proper operation of the attemperator component to prevent severe ID surface cooling.

Asset # 3	Asset # 4	Asset # 5	Description	Component	Major Issues	Remaining Life Years [1] (Insufficient Info - Inspection Required)	Remaining Life Comments	TECHNO-ECO RISK ASSESSMENT MODEL			SAFETY RISK ASSESSMENT MODEL			Possible Failure Event	Mitigation
								Likeli-hood	Conse-quence	Risk Level	Likeli-hood	Conse-quence	Safety Risk		
8359	8372		MAIN STEAM LINES	Welds	creep cracking at welds, material thermal ageing	5	No apparent life limiting issue.	1	B	Med	2	C	Med	Creep cracking.	Ensure correct operations and maintain supports
8359	8372		MAIN STEAM LINES	Hot Reheat E/W Combined Stop Valves	creep cracking at welds, thermal fatigue cracking at welded connections	10	No apparent life limiting issue.	1	B	Low	1	C	Low	Creep cracking.	Monitor hanger responses in hot and cold condition.
8359	8372	8373	BOILER STOP VALVE	Welds to Piping	creep cracking at welds, thermal fatigue cracking at welded connections	10	No apparent life limiting issue.	2	B	Low	1	C	Low	Creep cracking.	Routine inspections of welds.
8359	8384		REHEATER	Reheater Inlet Header	Thermal fatigue.	10	Could meet the desired life with routine inspections.	1	B	Low	1	C	Low	Thermal fatigue cracking.	
8359	8384		REHEATER	Reheater Outlet Header	Creep and thermal fatigue	10	ID wall loss should be monitored. Could meet the desired life with routine inspections.	2	D	Med	1	D	Med	Creep and thermal fatigue cracking.	
8590 - Unit 3 BOILER FEEDWATER PUMPING															
8590	8860		BOILER FEED PUMP WEST	Discharge Piping/Bends	FAC	4	Feedwater chemistry conducive to FAC. Moderate evidence of FAC. Turbulence caused by ID weld tips can accelerate damage. Can meet desired life with routine inspections.	3	B	Med	2	C	Med	Pipe failure due to thinned wall.	Re-inspection to monitor wall loss. Consider feedwater system assessment and possible adjustment to system chemistry.
8611 - UNIT 3 HIGH PRESSURE FEEDWATER SYSTEM															
8611	8620		H.P. HEATER 6	Discharge Piping/Tee	FAC	4	Feedwater chemistry conducive to FAC. Moderate evidence of FAC. Repaired and other thinned areas require re-inspection in order to meet desired life.	3	B	Med	2	C	Med	Pipe failure due to thinned wall.	Re-inspection to monitor wall loss. Consider feedwater system assessment and possible adjustment to system chemistry.
7789 - UNIT 2 F.W. & SAT'D STEAM SYSTEM															
7789	7794		STEAM DRUM	Riser tubes	Pitting and corrosion fatigue	>10	No apparent life limiting per inspections to date. ID inspection required.	1	C	Low	1	B	Low	Ligament cracking. Weld cracking.	Use of proper lay-up procedures to reduce pooling of condensate and oxygen ingress.

Asset # 3	Asset # 4	Asset # 5	Description	Component	Major Issues	Remaining Life Years [1] (Insufficient Info - Inspection Required)	Remaining Life Comments	TECHNO-ECO RISK ASSESSMENT MODEL			SAFETY RISK ASSESSMENT MODEL			Possible Failure Event	Mitigation
								Likeli-hood	Conse-quence	Risk Level	Likeli-hood	Conse-quence	Safety Risk		
7789	7790		ECONOMIZER	Inlet Header	Thermal/Mechanical Fatigue Cracking, Corrosion-Fatigue Cracking, Corrosion, FAC.	1	Life is limited by inlet Tee FAC. Inlet Tee replacement should be considered.	4	C	High	3	B	Med	Failure of inlet T. Feedwater leakage into boiler. Boiler off-line until replacement inlet T and other damaged head components can be replaced.	Replace Inlet Tee or re-inspect to ensure sufficient wall thickness. Monitoring of header temperature and start-up practices required.
7810 - UNIT 2 SUPERHEATER & REHEAT ASSEMBLY															
7810	7813		SUPERHEATER ATTEMPERATOR	Link Piping	Thermal/Mechanical Fatigue, corrosion fatigue	>10	No real issue as per external visual inspection to date.	1	C	Low	1	C	Low	Thermal/Mechanical Fatigue Cracking, Corrosion-Fatigue Cracking, Wall thinning due to corrosion related mechanisms.	
8059 - UNIT 2 HIGH PRESSURE FEEDWATER SYS															
8059	8067		H.P. HEATER 5	Discharge Piping and Tee	FAC	6	Feedwater chemistry conducive to FAC. Moderate evidence of FAC. Turbulence caused by ID weld tips can accelerate damage. Can meet desired life with routine inspections.	3	B	Med	2	C	Med	Pipe failure due to thinned wall.	Re-inspection to monitor wall loss. Consider feedwater system assessment and possible adjustment to system chemistry.
6701 - UNIT 1 F.W. & SAT'D STEAM SYSTEM															
6701	6869		ECONOMIZER	Inlet Header	Thermal/Mechanical Fatigue Cracking, Corrosion-Fatigue Cracking, Corrosion, FAC.	10	Sizing of cross ligamanet cracking, wall thickness measurements, and critical crack size assessment necessary.	2	B	Low	1	B	Low	Ligament cracking, tube stub thinning/cracking, weld cracking.	Monitoring of header temperature and start-up practices required.
Unit 1 Generator															
6696	6839	0	Generator	Rotor winding	Insulation wear out, and copper deformation to point of being non-reusable at time of rewind	5-10	Rotor presently beyond design life. Insulation failure is likely within 10 years.	2	D	MED	1	A	LOW	Insulation failure requiring immediate rewind and extended outage	Rewind proactively
6696	6839	0	Generator	Rotor forging	Fatigue cracking of the rotor	(30)	Remaining life depends on nature of the defect and reparability	1	D	MED	1	D	MED	Rotor failure causing catastrophic failure	Inspect rotor by NDE
6696	6840	0	Generator	Stator winding	Insulation wear out	5-10	Stator winding insulation is beyond design life. Insulation failure is likely within 10 years	2	D	MED	1	A	LOW	Insulation failure causing ground fault, requiring full rewind and extended outage	Rewind proactively
6696	6840	0	Generator	Stator core	Minor Core fault (major fault unlikely)	30	Testing indicates no life limiting issues	2	C	MED	2	A	LOW	Minor core fault requiring removal of rotor for repair	Conduct ELCID test and visual inspection with rotor out

Asset # 3	Asset # 4	Asset # 5	Description	Component	Major Issues	Remaining Life Years [1] (Insufficient Info - Inspection Required)	Remaining Life Comments	TECHNO-ECO RISK ASSESSMENT MODEL			SAFETY RISK ASSESSMENT MODEL			Possible Failure Event	Mitigation
								Likeli-hood	Conse-quence	Risk Level	Likeli-hood	Conse-quence	Safety Risk		
Unit 3 Generator															
8194	8298	8299	Generator	Rotor winding	Insulation wear out, and copper deformation to point of being non-reusable at time of rewind	5-10	Rotor presently beyond design life. Insulation failure is likely within 10 years.	2	D	MED	1	A	LOW	Insulation failure requiring immediate rewind and extended outage	Rewind proactively
8194	8298	8299	Generator	Rotor forging	Fatigue cracking of the rotor	(30)	Remaining life depends on nature of the defect and reparability	1	D	MED	1	D	MED	Rotor failure causing catastrophic failure	Inspect rotor by NDE
8194	8298	8304	Generator	Stator winding	Insulation wear out	5-10	Stator winding insulation is beyond design life. Insulation failure is likely within 10 years	2	D	MED	1	A	LOW	Insulation failure causing ground fault, requiring full rewind and extended outage	Rewind proactively
8194	8298	8304	Generator	Stator core	Minor Core fault (major fault unlikely)	30	Testing indicates no life limiting issues	2	C	MED	2	A	LOW	Minor core fault requiring removal of rotor for repair	Conduct ELCID test and visual inspection with rotor out
7203 - HRD WATER TREATMENT PLANT															
7203	7210	7534	Quarry Brook Dam and Fishway System	Raw water line	Asbestos-cement pipe corrosion	25	Possible leakage found.	2	B	Low	3	A	Low	Pipe failure halting supply of water to pumphouses.	Assess economic impact of recurring failure near end of plant lfe (2041)
7255 - HRD BUILDINGS															
7255	**272255**	7283	HRD Main Powerhouse	Powerhouse siding	Rusting of steel sheet metal and fastenings	1-5	Life-limited by rusting observed.	3	B	Med	2	D	High	Siding piece falls damaging switch yard equipment or causing injury.	Replace siding in segments in order of priority for degraded areas.

[1] It is assumed the units have and will continue to be operated within limits (temperatures and pressures) specified by operating procedures.

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Appendix A: Holyrood TGS Level II Condition Assessment – NDE Scope[1]

Sub-component	Issue	Locations for Inspection	NDE Method						NDE Comment	Comments Findings
			MT	UT	Replica	PAUT[2]	RT	Visual		
Unit 1 and 2 Boiler										
Waterwall tubes	• ID Corrosion Fatigue cracking	Cold side attachments • Top of burner Cor 2 • Buckstay corner Elev 59'-10' Cor 1 • Buckstay cor at Rear wall, elev 64'-10", cor 3 • Side wall/ slope at buckstay, elev 26'-11" west wall					X		RT from outside of boiler (film on boiler interior)	No indications of ID cracking
Waterwall Risers (penthouse)	• ID Corr Fatigue at neutral axis of bends	Sample of 10 risers identified by inspection • Bends for cracking		X				X	• Boroscope from inside drum for ID cracking in neutral axis (90^o & 270^o)	
	• Oxygen pitting	• Horizontal sections for pitting					X		• Pitting in horizontal sections (sagging) • RT for pitting	
	• OD Fatigue at nozzles		X						• External MT at drum weld	
Boiler Drum	• General fitness • Thermal fatigue cracking	General visual of drum internal for major damage (remove internals and baffles)						X	• General visual •	Only cyclones removed No unusual indications
		Riser and sat steam nozzles at drum ID	X					X	• 3 sections, about 10% each, selected during general visual inspection • Internal visual of risers (boroscope)	U1 inspected , no damage found

[1] Shaded areas identify inspections completed in 2012/13/14 to date
[2] PAUT = Focused Phased Array and TOFT/Linear Phased Array

Sub-component	**Issue**	**Locations for Inspection**	**NDE Method**						**NDE Comment**	**Comments** **Findings**
			MT	UT	Replica	PAUT[2]	RT	Visual		
		Seam welds (sample sections)	X						• 1m section of lower and upper axial seam alternative between courses • 1m sections of circ welds including T, top and bottom , alternating between courses	Upper Seam weld
		Downcomer penetrations	X						Inaccessible internal areas Inside drum	Thermal fatigue cracking found at all four downcomers
		Drum Head Penetrations and Shell	X	X					• MT of penetrations • UT wall thickness of shell and heads	Part of annual survey Minor findings consistent with previous inspections.
		Boroscope ID of safety valve internal						X	Boroscope of nozzle ID to exterior of drum	NR no damage at other nozzles
Downcomer	Thermal fatigue on ID	Downcomer to H1 header nozzle welds		X		X		X	Boroscope inspection of H1 ID Linear PUAT of 2 dwncr to H1	ID Visual inspection complete
		Downcomer to steam drum nozzle welds	X					X	50% from inside drum (2 downcomers) Inspect weld 0.5m down from Drum ID	NR No damage at other high stress
	Fatigue on OD	Header Support Welds (50%)	X							NR Low Priority. No evidence to support fatigue damage
Ec Inlet Hdr	• Corrosion fatigue (circ) cracking in stub tubes • Thermal fatigue on ID of header • FAC in header or stub tubes	Inlet Hdr stub tubes First, last and middle 5 tubes (15 total)		X		X			Shear wave (PAUT) on tubes for circ ID cracking & thickness measurement	
		Inlet header (post-cleaning)				X		X	UT as required to size defects Boroscope on ID	ID boroscope inspection in 2014. Found borehole corner cracking and evidence of FAC. Pad welds required for continued operation.
SH4	• Thermal fatigue cracking on the ID	Inspect Girth weld	X	X	X	X		X	1 circ weld UT – Thickness Linear PAUT of weld Focused PAUT as required, at least one replica	NR Low Priority on Life Fraction Assessment

Sub-component	Issue	Locations for Inspection	NDE Method						NDE Comment	Comments Findings
			MT	UT	Replica	PAUT[2]	RT	Visual		
	• Creep in weld	Visual inspection of ID, for macro cracking						X	Boroscope of ID	NR high remaining life from Level I assessment
Link Piping	• Creep in seam weld	Piping downstream of attemperator Penthouse access needed may require type 3 asbestos abatement.	X	X	X	X			Etch 2 pipes to assess if seam welded If seam welded, inspect seam (50%) Liner PAUT and Focused PAUT if anomalies found, replica and wall thick	
Main steam header (SH6)	Creep/ Creep Fatigue	Header thickness		X					Measure between circ welds	Access and cleaning of Header and supports
		Header ID visual						X	Boroscope of ID (ligaments, drain, nozzle)	Remove handhole cap No relevant indications. Findings supported by inspection in 2010
		Header girth welds (50%) At least one weld without a nozzle – to be confirmed on dwgs	X		X	X			Thickness + Linear PAUT of weld +1 replica – more if anomalies found	Low priority due to construction – only girth welds are external to boiler. Main concern is nozzle welds
		Header head seam welds (50%)	X		X	X			3 sections of hdr comprising 50% of length – etch if necessary to locate Lear PAUT of target length Focused PAUT of anomalies + 3 sample locations	Partial etch done to locate weld. No weld located Full circ etch required
		Header outlet nozzle welds (50% - 1 nozzle)	X	X	X	X			Thickness + Linear PAUT of weld +1 replica – more if anomalies found	Damage found in both east and west nozzle welds
		Header supports (50%)	X							
	Thermal fatigue	Drain (also seem to act as a vent. Inspect at weld to hdr in hdr vestibule)	X						External welds Interior thermal fatigue should be evident from boroscope inspection	NR Low priority
CRH Header	Thermal fatigue	CRH Header Internals						X	Boroscope ID through handhole cap	No relevant indications identified

Sub-component	Issue	Locations for Inspection	NDE Method						NDE Comment	Comments Findings
			MT	UT	Replica	PAUT[2]	RT	Visual		
HRH Header	Update creep life estimate	Header thickness		X					Between circ welds	
	Creep/ Creep Fatigue	HRH Header Internal						X	Boroscope	No indications identified
		Header Supports (50%)	X							No indications identified
		Header Girth Welds (50%)	X		X	X			Thickness + Linear PAUT of weld +1 replica – more if anomalies found	No indications Replication not completed
		Header Seam Welds (50%) PAUT as req'd to size indications	X	X	X	X			3 sections of hdr comprising 50% of length – etch if necessary to locate Linear PAUT of target length Focused PAUT of anomalies + 3 sample locations at least 1 replica	Partial etch completed. No weld identified. Full circ etch required
		Header outlet nozzle welds (%50)	X	X	X	X			Thickness + Linear PAUT of weld +1 replica – more if anomalies found	East nozzle inspected. No indications identified Replication not completed
Reheat Tubes	Creep-type damage in Dissimilar Metal Weld	Remove two dissimilar metal welds from Reheat outlet bank							Destructive metallurgical analysis	Tubes containing welds to be replaced due to ID off-line corrosion
Unit 3 Boiler										
Penthouse Riser Tubes.	Corrosion fatigue in neutral axis of bend	Inspect select short radius bends				X			10 risers at bends, 1' section, selected by inspection and RT for pitting External MT at drum weld	NR No evidence of movement causing fatigue
	Oxygen Pitting	Inspect sample horizontal sections					X		Sample feeders to be selected by inspection – look for ID pitting in lower half of feeder	
	Fatigue	Inspect sample nozzle welds at steam drum	X						10 riser nozzles – same feeders as selected for bend	

Sub-component	**Issue**	**Locations for Inspection**	**NDE Method**						**NDE Comment**	**Comments Findings**
			MT	UT	Replica	PAUT[2]	RT	Visual		
									inspection	
Lower Downcomer Header	Thermal fatigue at bore holes	One header (east or west)		X				X	Wall thickness and internal boroscope	
Lower WW Header	Thermal fatigue	One header internal visual inspection at bore holes and at flat end plug weld		X				X	Wall thickness and internal boroscope.	
Unit 1 Main Steam Piping										
West Boiler Link	Creep & Creep Fatigue	• Girth Weld • Thermowell • Gamma plug	X	X	X	X		X	MT on Gamma plug and thermowell MT, PAUT, UT, Replica on girth weld	
Shop Weld Above Stop Valve	Creep & Creep Fatigue	• Shop Weld above BSV • Instrument penetrations	X	X	X	X		X	MT on Gamma plug and thermowell MT, PAUT, UT, Replica on girth weld	
Boiler Stop Valve Inlet weld	Creep & Creep Fatigue	• Boiler Stop Valve, upstream weld • Gamma plug • Hanger lugs • Drain	X	X	X	X		X	MT on Gamma plug hanger lug, drain and thermowell MT, PAUT, UT, Replica on girth weld	
Main Stop Valve Inlet	Creep & Creep Fatigue	• Girth Weld • Drain & Gamma plug	X	X	X	X		X	MT on Gamma plug and drain MT, PAUT, UT, Replica on girth weld	
East Turbine Gov Valve Terminal	Creep & Creep Fatigue	• Flange Weld	X	X	X	X		X	MT, PAUT, UT, Replica on girth weld	Not a flange
Unit 1 Hot Reheat Piping										
West Boiler Link	Creep & Creep Fatigue	• Girth Weld • Thermo Well • Gamma plug	X	X	X	X		X	MT on Gamma plug and thermowell MT, PAUT, UT, Replica on girth weld	

Sub-component	**Issue**	**Locations for Inspection**	**NDE Method**						**NDE Comment**	**Comments Findings**
			MT	UT	Replica	PAUT[2]	RT	Visual		
Lower Y Inlet	Creep & Creep Fatigue	• Girth Weld • Hanger lugs • Gamma plug	X	X	X	X		X	MT on Gamma plug and thermowell MT, PAUT, UT, Replica on girth weld	**Thickness data is required**
East CSV Inlet	Creep & Creep Fatigue	• Girth Weld • Drain	X	X	X	X		X	MT on drain MT, PAUT, UT, Replica on girth weld	
East Turb Terminal	Creep & Creep Fatigue	• Flange Weld (Under Turbine)	X	X	X	X		X	MT, PAUT, UT, Replica on girth weld	
Unit 1 Cold Reheat Piping										
West Boiler Link	Fatigue	• Girth Weld OD and ID	X	X		X		X	MT, UT and PAUT on Weld Looking for ID fatigue cracking	
Lower Y Inlet, & Hanger Lug	Fatigue	• Girth Weld • Hanger Lug above Y	X	X		X		X	MT, UT and PAUT on Weld, MT on lug	
West Turbine Terminal	Fatigue	• Flange Weld	X	X		X		X	MT, UT and PAUT on Weld Looking for ID fatigue cracking	NR
Unit 2 Main Steam Piping										
East Boiler Link	Creep & Creep Fatigue	• Girth Weld • Thermowell • Gamma plug	X	X	X	X		X	MT on Gamma plug and thermowell MT, PAUT, UT, Replica on girth weld	No evidence of creep voids
Upper Y East Side	Creep & Creep Fatigue	• Upper Y East Inlet Weld • Crotch of Y • East Hanger Lug • Gamma plug	X	X	X	X		X	MT on Gamma plug and thermowell MT, PAUT, UT, Replica on girth weld, and Y crotch	NR No damage in U1
West Main Stop Valve Outlet	Creep & Creep Fatigue	• Girth Weld • Gamma plug •	X	X	X	X		X	MT on Gamma plug MT, PAUT, UT, Replica on girth weld	East MSV Outlet Nozzle completed on Unit 1 in 2013
West Turb	Creep & Creep	• Flange Weld	X	X	X	X		X	MT, PAUT, UT, Replica on	Possible Isolated creep voids

Sub-component	**Issue**	**Locations for Inspection**	**NDE Method**						**NDE Comment**	**Comments** **Findings**
			MT	UT	Replica	PAUT[2]	RT	Visual		
Gov Valve Terminal	Fatigue								girth weld	In HAZ (Type III)
Unit 2 Hot Reheat Piping										
East Boiler Link	Creep & Creep Fatigue	• Girth Weld • Thermowell • Gamma plug	X	X	X	X		X	MT on Gamma plug and thermowell MT, PAUT, UT, Replica on girth weld	No evidence of creep voids
Upper Y East Leg and Crotch	Creep & Creep & Creep Fatigue	• Upper Y east weld and crotch • Hanger lug – east side • Gamma plug	X	X	X	X		X	MT on Gamma plug MT, PAUT, UT, Replica on girth weld, and Y crotch	No evidence of creep voids
West CSV Outlet	Creep & Creep Fatigue	• Girth Weld	X	X	X	X		X	MT, PAUT, UT, Replica on girth weld	West CSV Outlet Nozzle Weld completed on Unit 1 in 2013 **Thickness data is required**
Unit 2 Cold Reheat Piping										
East Boiler Link	Fatigue	• Girth Weld	X	X		X		X	MT, UT and PAUT on Weld Looking for ID fatigue cracking	No Evidence of Damage
Htr 6 Bleed Steam Nozzle	Fatigue	• Htr 6 Bleed Steam Nozzle Weld	X	X		X		X	MT, UT and PAUT on Weld Looking for ID fatigue cracking	Recommended
East Turbine Terminal	Fatigue	• Flange Weld	X	X		X		X	MT, UT and PAUT on Weld Looking for ID fatigue cracking	NR
Unit 3 Main Steam Piping										
West Boiler Link	Creep & Creep Fatigue	• Girth Weld • Gamma plug	X	X	X	X		X	MT on Gamma plug MT, PAUT, UT, Replica on girth weld,	
Upper Y and BSV	Creep & Creep Fatigue	• Boiler Stop Valve outlet • Upper Y West Leg and crotch • Hanger Lugs	X	X	X	X		X	MT on Gamma plug, drain and lug MT, PAUT, UT, Replica on girth weld, and Y crotch	

Sub-component	**Issue**	**Locations for Inspection**	**NDE Method**						**NDE Comment**	**Comments Findings**
			MT	UT	Replica	PAUT[2]	RT	Visual		
		• Drain & Gamma plug								
West Main BSV Inlet	Creep & Creep Fatigue	• West Main Stop Valve Inlet • Gamma plug • Drain • Thermowell + Press Tap	X	X	X	X		X	MT on Gamma plug, drain & inst connections MT, PAUT, UT, Replica on girth weld, and Y crotch	
West Boiler Terminal Above Turb deck at flange	Creep & Creep Fatigue	• Flange Weld	X	X	X	X		X	MT, PAUT, UT, Replica on girth weld	
Unit 3 Hot Reheat Piping										
West Boiler Link	Creep & Creep Fatigue	• Girth Weld • Gamma Plug	X	X	X	X		X		
Lower Y Inlet	Creep & Creep Fatigue	• Girth Weld • Hanger lugs • Gamma plug	X	X	X	X		X		
West CSV Inlet	Creep & Creep Fatigue	• Girth Weld • Drain + Press Tap • Gamma plug	X	X	X	X		X		
East Turbine Terminal	Creep & Creep Fatigue	• Flange Weld	X	X	X	X		X	West terminal inspected due to access issues.	
Unit 3 Cold Reheat Piping										
West Boiler Link	Fatigue	• Girth Weld	X	X		X		X		
East Turb Terminal	Fatigue	• Flange Weld	X	X		X		X		NR Low Priority due to lack of movement in piping
Drain & Inst Connection East Leg	Fatigue	• Drain & Inst connections below turbine, east side	X	X		X		X		
Unit 1 Feedwater Piping										

Sub-component	Issue	Locations for Inspection	NDE Method						NDE Comment	Comments Findings
			MT	UT	Replica	PAUT[2]	RT	Visual		
HP Feedwater Piping	FAC	• P1 BFP disch elbow & expander		X					UT wall thickness on grid	
HP Feedwater Piping	FAC	• HP Flow Element		X					UT wall thickness on grid	
HP Feedwater Piping	FAC Thermal Fatigue	• EC inlet elbow		X		X			UT wall thickness on grid PAUT at weld root and counterbore notch	
SH Attemper-ator	FAC	• West SH Attemp Valve Station		X					UT wall thickness on grid Scan small bore (<= 2")	
BFP Recirc Piping	FAC	• BFP 2 recirc FCV and piping		X					UT wall thickness on grid	Recommended
LP Feedwater Piping	FAC	• 2nd elbow before DA		X					UT wall thickness on grid	NR No Damage in LP piping
Unit 2 Feedwater Piping										
HP Feedwater Piping	FAC	• P1 Disch Elbow		X					UT wall thickness on grid	
HP Feedwater Piping	FAC	• Htr 4 Disch double elbow		X					UT wall thickness on grid	Evidence of FAC
HP Feedwater Piping	FAC	• Htr 5 Disch Tee		X					UT wall thickness on grid	
HP Feedwater Piping	FAC Thermal Fatigue	• Htr 6 Disch Valve, elbow		X		X			UT wall thickness on grid PAUT at weld root and counterbore notch	NR Check valve recently serviced. No damage found
SH Attemper-ator	FAC	East SH Attemp Supply Flow Element + piping and Valve Station		X					UT wall thickness on grid	Possible wall thinning down stream of TV619C

Sub-component	Issue	Locations for Inspection	NDE Method						NDE Comment	Comments Findings
			MT	UT	Replica	PAUT[2]	RT	Visual		
LP Feedwater Piping	FAC	• Elbow and T out of #2 heater		X					UT wall thickness on grid	No evidence of FAC
Unit 3 Feedwater Piping										
HP Feedwater Piping	FAC	• P1 BFP Disch piping, thermowells, and elbows		X					UT wall thickness on grid	Evidence of FAC but not a concern within current target life
HP Feedwater Piping	FAC	• P2 BFP 45Deg Branch + reducer		X					UT wall thickness on grid	NR Not life limiting Damage at 90 deg Elbow
HP Low Flow Piping	FAC	• Tees to low flow and attempt + reducer		X					UT wall thickness on grid	NR Outlet tee and piping inspected with no Damage
HP Low Flow Piping	FAC	• Low flow disch to main run - tee + downstream elbow		X					UT wall thickness on grid	Evidence of FAC but not a concern within current target life
HP Feedwater Piping	FAC Thermal Fatigue	• Elbow before EC		X		X			UT wall thickness on grid PAUT at weld root and counterbore notch	Evidence of FAC but not a concern within current target life
LP Feedwater Piping	FAC	• LP Feedwater flow element above Htr 2		X					UT wall thickness on grid	NR
SH Attemper-ator Feedwater Station	FAC	East SH Attemp Supply Flow Element + piping and Valve Station		X					UT wall thickness on grid	Possible wall thinning upstream of block valve, at first inlet bend. Pipe was part of replacement in 2010; findings may be due to initial wall variations and not FAC.
HP Feedwater Piping	FAC	• No. 6 Heater discharge bends and full flow Tee.		X						
Unit 3 Generator										
Rotor	General aging	•						X	Resistance measurements and other specialized tests also	

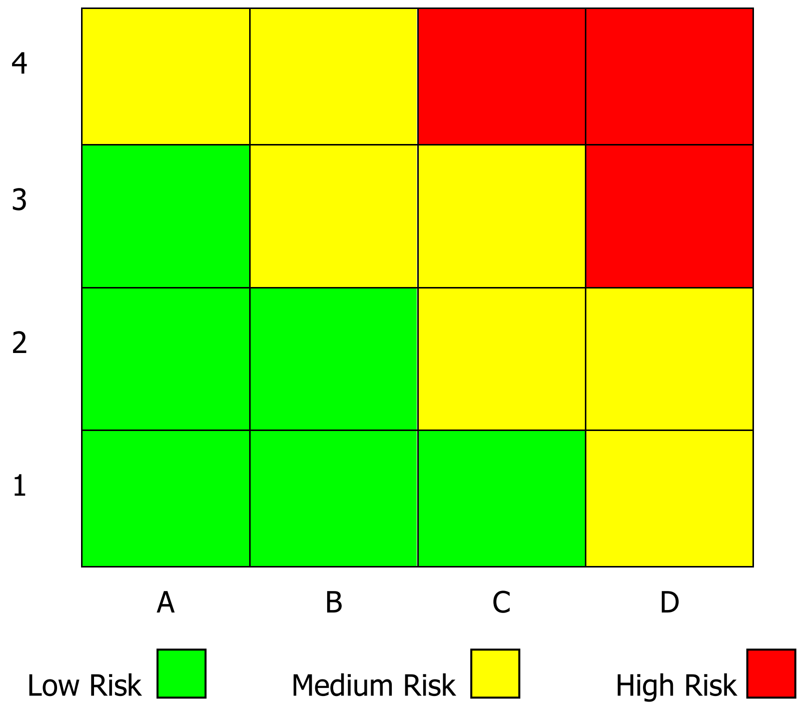
Sub-component	Issue	Locations for Inspection	NDE Method						NDE Comment	Comments Findings
			MT	UT	Replica	PAUT[2]	RT	Visual		
	and wear								performed	
Stator	General aging and wear	•						X	Resistance measurements and other specialized tests also performed	
Unit 1 Generator										
Rotor	General aging and wear	•						X	Resistance measurements and other specialized tests also performed	
Stator	General aging and wear	•						X	Resistance measurements and other specialized tests also performed	

Appendix B: Risk Models

Technical Risk

The risk assessment model has been developed based on methods proposed by the American Petroleum Institute (API RP 580), in lieu of a model specific to the power utility industry. The 4x4 model below was developed for the Holyrood Thermal Generating Station Condition Assessment Life Extension Study. The consequence of an adverse event is measured in cost terms on the horizontal axis and the likelihood or frequency of the event on the vertical axis.

Technological risk of Failure Analysis Model



Likelihood of Failure Event:

1. Greater than 10 years
2. 5 to 10 years
3. 1 to 5 years
4. Immanent (< 1 year)

Consequence of Failure Event:

A. Minor ($10k-$100k or derating/1 day outage)
B. Significant ($100k-$1m or 2-14 days outage)
C. Serious ($1m-$10m or 15-30 days outage)
D. Major (>$10m or >1 month outage)

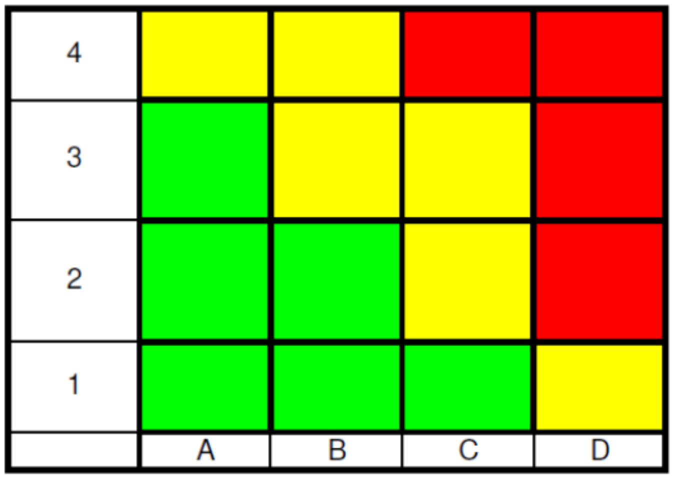
Actions:

- Items that do not apply are not ranked
- Low Risk: Monitor long term (within 5 years)
- Medium Risk: Investigate and monitor short term. Take action where beneficial
- High Risk: Corrective action required short term

Safety Risk Failure Analysis

In addition to the technological risk of failure analysis, a preliminary safety risk of failure analysis was undertaken at NL Hydro's request. Its basic format is based on that of the technological risk assessment model above and is somewhat of a hybrid of the more complex "Real Hazard Index" model used by the US Department of Defence. The modified model is presented below in Table 3-2.

Safety Risk of Failure Analysis Model



Low Risk Medium Risk High Risk

Likelihood of Safety Incident Event:

1. Improbable – so that it can be assumed not to occur
2. Unlikely to occur during life of specific item/process
3. Will occur once during life of specific item/process
4. Likely to occur frequently

Consequence of Safety Incident Event:

A. Minor - will not result in injury, or illness
B. Marginal - may cause minor injury, or illness
C. Critical - may cause severe injury, or illness
D. Catastrophic - may cause death

Actions:

- Items that do not apply are not ranked;
- Low Risk: Monitor, take action where beneficial;
- Medium Risk: Investigate and monitor short term. Take action where beneficial; and
- High Risk: Unacceptable. Corrective action required short term

Appendix C: Creep Life Calculations

Project Title:	Holyrood Condition Assessment Phase 2
Client:	Newfoundland and Labrador Hydro
Title:	Review of Ultrasonic Thickness Measurements for Steam Headers and Piping

1.0 INTRODUCTION

1.1 Problem Definition

Newfoundland and Labrador Hydro, a subsidiary of Nalcor Energy, owns and operates the Holyrood Thermal Generation Station (HTGS). The station is equipped with three oil-fired generation units which were originally commissioned in 1969, 1970, and 1979, respectively, at a rated output of 150 MW per unit. The first two units were modified and uprated to 170 MW in 1988 and 1989 respectively, bringing the total generation capacity of the plant to 490 MW.

Nalcor Energy requires that the HTGS operate as currently configured until 2018. Units 1 and 2 will then be decommissioned, and Unit 3 is expected to continue as a synchronous condensing facility until 2041. A thermal generation station, operating continuously between outages for routine repairs and maintenance, has a typical life expectancy of 30 years. The HTGS has only experienced annual CF's in the 30% to 50% range since the plant went into service, because the abundance of hydro-electric power allows for the HTGS to be run at low loads, or not at all, from late spring to late fall each year. Nevertheless, engineering studies are needed to identify components and/or systems requiring remedial measures (maintenance, inspection and/or analysis) for continued reliable operation of the HGTS to 2020.

1.2 Objectives

In 2010, AMEC NSS performed a Level I Condition Assessment of the boilers, high energy piping and major pressure vessels in the HTGS [1]. The objectives of the Level I assessment were to assess the remaining lives of these components and to identify potential degradation mechanisms that could adversely affect remaining life and reliability over the target operating period. Design and historical operating and maintenance data were used as the basis for remaining life assessments.

Nalcor Energy has contracted AMEC NSS to perform a follow-up Level II Condition Assessment to: (i) confirm potential degradation problems identified in the Level I assessment, (ii) validate remaining life predictions from the Level I assessment, (iii) and provide recommendations for either life management or follow-up actions to ensure desired life and performance is achieved [10].

In support of this Level II Condition Assessment, ultrasonic thickness measurements of the following high energy piping components in Unit 3 were obtained:

- Cold Reheat West Link @ Level 7 (16″ Piping)
- CRH East Horizontal Run @ Level 2 (16″ Piping)
- CRH at drain below turbine @ Level 2 (16″ Piping)
- Hot Reheat (HRH) East Link @ Level 9 (16″ Piping)
- HRH Lower Y@ Level 3 (20″ Piping)
- HRH East/West Combined Stop Valve Inlet (16″ Piping) and Outlet (18″ Piping) @ Level 2
- Main Steam (MS) East Link @ Level 8 (10¾″ Piping)
- MS Boiler Stop Valve outlet @ Level 8 (13 3/8″ Piping)
- MS Upper Turbine Terminal @Level 3 (8 33/64″ Piping)
- MS Main Stop Valve inlet @ Level 2 (10¾″ Piping)
- High Temperature Reheater Outlet Header (Hot Reheat)
- High Temperature Superheater Front horizontal spaced Outlet Header (Main Steam)

The objectives of this calculation note are to (i) review the thickness measurements for the high temperature components; (ii) assess the impact of these measurements on the validity of the creep rupture analyses of these components in the Level I Condition Assessment.

2.0 REVIEW OF WALL THICKNESS MEASUREMENTS

The inspection reports for the ultrasonic wall thickness measurements are in reference [2]. The results for the components listed above are given in Table 5. For each component multiple measurements were taken. A minimum measurement was also taken as part of the phase array inspection procedure. For the CRH horizontal run, a table of measurements was generated as part of an investigation into possible inside diameter pitting.

Table 1 also compares the minimum measured wall thickness for each component with the creep life calculation minimum wall thickness, and the pressure-based minimum wall thickness (as per Section I, Paragraph PG-27 of the ASME B&PV Code [5]). During Phased Array Ultrasonic Testing (PAUT) low wall thickness was noted in the West Hot Reheat Turbine Terminal piping. An area of local thinner wall was noticed however no expected degradation mechanism could account for the findings. It was concluded that the anomaly was the result of a manufacturing defect that although low, was still above the calculated, pressure-based minimum wall thickness. The lowest measurement of 0.74″ has been reported here.

The minimum wall thickness for the hot reheat and main steam header are specified in the design drawings [3][4] and are the same as minimum thicknesses used in the creep life calculationsTable 6. Table 8 summarizes the parametric equations from API

579-1/ASME FFS-1 [6] that were used to estimate minimum Larson-Miller Parameters (LMP*) for the piping materials.

The minimum measured wall thickness for each component exceeds the corresponding pressure-based minimum wall thickness (see Table 5). In three (3) instances the measured wall thickness is below the mean less 12.5% mill tolerance used for the creep life calculations (cold reheat west boiler link, main steam boiler stop valve outlet, hot reheat west combine stop valve inlet).

3.0 IMPACT ON LEVEL I CREEP RUPTURE ANALYSES

3.1 Unit 3 Operating Hours

Unit 3 has accumulated 139,821 operating hours. The unit is expected to accumulate an additional 35,965 hours[3] of operation by the end of the 2018 operating season (June 2019). The total expected life at the end of the 2019 operating season (June 2020) is 183,253[4] hours. The previous assessment estimated the end of life to be at 179,099 hours which remains a valid conservative estimate of the operation hours. The additional operating hours are based on an operating factor of 85% from the start of September 2014 to the end of June 2019.

3.2 Previous Creep Life Calculation Results

The main steam piping, secondary superheat outlet header, and reheater outlet header (hot reheat header) were the most limiting components in the creep rupture analyses of the Level I Condition Assessments of HTGS Unit 3 [8][9]. The highest LFE[5] value under MCR[6] conditions was predicted for the main steam piping: LFE = 0.23 for every 100,000 hours of operation under MCR conditions[7]. Based on the above data, the LFE value for the main steam piping in Unit 3 would not reach 1.0 until Unit 3 had accumulated ~425,619 operating hours[8].

3.3 Update of Previous Calculations with Measured Wall Thicknesses

The creep rupture analyses of the Level I Condition Assessments of HTGS Unit 3 were based on the specified minimum wall thickness and the calculated hoop stress based on the system pressure and with consideration for the system temperature (Table 7). Where credible data is available the wall thickness measurements exceed the corresponding specified minimum wall thickness used for the creep rupture analyses, with the following exceptions: Cold Reheat west boiler link (16” OD), main steam boiler stop valve outlet pipe (13.375” OD), the hot reheat west inlet CSV (16” OD). The calculations bound the higher wall thickness measurements. For the lower wall

---

[3] 8760 x [0.85 x (1763 days from September 1, 2014 to June 30, 2019)] = 35,965 hrs
[4] 8760 x [0.85 x (2129 days from September 1, 2014 to June 30, 2020)] = 43,432 hrs
[5] Life Fraction Expended
[6] Maximum Continuous Rating
[7] See creep rupture calculations for piping in EXCEL spreadsheet “AM160_Creep_Without EK_FINAL_2014.xls” [7]. See creep rupture calculations for headers in “AM160_Creep_With EK_FINAL_2014.xls” for headers [7].
[8] 1/0.23*100,000= 425,619 hrs for Unit 3

thickness locations the creep life calculations were updated to consider the new minimum measured wall thicknesses.

The results for straight piping and non-straight piping (with a factor of 1.1) are given in Table 9 and Table 10 respectively. The following results use the more conservative non-straight piping results. The analysis indicates that the LFE for the cold reheat remains well below 0.1%. The 13.375" main steam pipe is the most limiting LFE under MCR conditions, so the new wall thickness changes the LFE value. The LFE goes from 0.23 to 0.24 per 100,000 hours of operation. This is not a drastic change but it does reduce the creep end of life from 425,976 to 412,573 hours. Despite this reduction 400,000 operating hours remains a conservative limiting end-of-life for creep rupture of high temperature components in Unit 3, provided there is no active wall thinning in these components.

3.4 Extension of Analysis to Turbine Steam Piping

The creep life assessment has been extended to the turbine steam piping. The 18" hot reheat turbine terminal pipe and the 8.516" main steam turbine terminal have been added to the assessment. The main steam turbine terminal is now the limiting creep life component. Using the measurements from the inspection work, the highest LFE per 100,000 hours is 0.38 under MCR conditions. The gives a maximum operating hours of 262,305. The conservative creep end-of-life is 250,000 hours.

General or local low temperature corrosion are not expected degradation mechanisms for these high temperature components. However, wall thinning due to high temperature oxidation and spalling of scale off the inner surfaces of the components cannot be ruled out because there are no previous wall thickness measurements to compare against the current measurements. It is recommended that wall thickness measurements of the high temperature headers and piping be repeated in 3 years time to assess potential wall loss rates, and implications for remaining life. Wall thickness measurement should consist of at least five locations to minimize the impact of measurement error and irregularities in wall thickness.

4.0 REFERENCES

[1] T. Mahmood, "HTGS Condition Assessment and Life Extension Study", AMEC NSS Report AM060/RP/001, May 13, 2010.

[2] "Inspection Results and Reference Binder", AMEC File No. AM160/RE/003 R00, November 2014.

[3] "Secondary Superheater Outlet Header", Babcock & Wilcox Drawing 1403-V-250-M-055 Rev F.

[4] "Reheater Outlet Header", Babcock & Wilcox Drawing 1403-V-250-M-05 Rev E.

[5] ASME Boiler and Pressure Vessel Code, 1965 edition.

[6] API 579-1/ASME FFS-1, "Fitness-For-Service", June 5, 2007.

[7] "Electronic Records and Analysis Files (EXCEL Spreadsheets, QA Records, References, and Calculation Notes)", AM160/CD/001, Nov. 11, 2014.

[8] R. Yee, "Creep Rupture Assessments of High-Temperature Headers in Holyrood Unit 3", AM060/CN/008, April 28, 2010.

[9] R. Yee, "Creep Rupture Assessments of High-Temperature Piping in Holyrood Unit 3", AM060/CN/009, April 28, 2010.

[10] Newfoundland and Labrador Hydro, Request for Proposals, "Condition Assessment and Life Extension Study, Phase II – Holyrood Thermal Generating Station", RFP 2012-57571, March 2014.

Table 5: Minimum Measured High Temperature Piping UT Measurements (inches)[1]

	CRH West Link	CRH Line	CRH Line (under Turbine)	HRH East Link	HRH West CSV Inlet	HRH West Turbine Terminal	HRH Lower Y Inlet	MS East Link	MS West Main Stop Valve	MS BSV Outlet	MS West Upper Turbine Terminal	Hot Reheat Header	Main Steam Header
Material	SA-106-B			SA-335-P22				SA-335-P22			SA-335-P22	SA-335-P22	SA-335-P22
Design Temperature T_{design} (°F)	712			1005				1005			1005	1030	1005
Code Allowable Stress[2] S (psi)	15000			7600				7600			7600	7600	7600
Design Pressure P_{design} (psi)	649			618				2070			2070	650	1890
Nominal Outer Diameter D (in)	16			16		18	20	10.75		13.75	8.516	20	14
weld factor[3] w	1			1				1			1	1	1
ligament efficiency e	1			1				1			1	1	1
Overal Efficiency Factor[8] E = min (w, e)	1			1				1			1	1	1
Temperature Factor[4] y	0.4			0.7				0.7			0.7	0.7	0.7
Stability Factor[5] C	0			0				0			0	0	0
pressure-based minimum wall thickness[6] $t_{min,p}$ (in)	0.340			0.615		0.692	0.769	1.230		1.530	0.974	0.807	1.483
pressure-based minimum wall thickness[6] $t_{min,p}$ (mm)	8.64			15.63		17.59	19.54	31.23		38.86	24.74	20.50	37.66

	CRH West Link	CRH Line	CRH Line (under Turbine)	HRH East Link	HRH West CSV Inlet	HRH West Turbine Terminal	HRH Lower Y Inlet	MS East Link	MS West Main Stop Valve	MS BSV Outlet	MS West Upper Turbine Terminal	Hot Reheat Header	Main Steam Header
specified minimum wall thickness[7] $t_{min,specified}$ (in)	0.605			0.800		0.72275	0.966	1.463		1.787	0.974	1.5	2.5
measured minimum wall thickness[8] $t_{min,measured}$ (in)	**0.500**[9]	0.587	0.598	0.94[9]	**0.792**	0.740[9]	1.029	0.94[9]*	1.581	**1.779**	1.063	1.624	2.568
measured maximum wall thickness[8] $t_{min,measured}$ (in)	0.700	0.717	0.664	NA	1.025	1.006	1.060	NA	1.768	1.822	1.123	1.699	2.629

[1] Design temperatures and dimensions from AM060/RP/001 [2].

[2] From Table PG-23.1, Appendix A-24, Section I, ASME B&PV Code (1965)

[3] As per Note 1, PG-27, Section I, ASME B&PV Code (1965)

[4] As per Note 6, PG-27, Section I, ASME B&PV Code (1965)

[5] As per Note 3, PG-27, Section I, ASME B&PV Code (1965)

[6] $t_{min,\ pressure} = PD/(2SE+2yP) + C$ PG-27b, Section I, ASME B&PV Code (1965)

[7] For HH and main steam piping, $t_{min,\ specified}$ = 0.875 x specified wall thickness from Table 4, Part IV of AM060/RP/001 [2], with exception of upper turbine terminal where 12.5% tolerance would be less than calculated ASME min. ASME min is used for MS upper turbine terminal.

[8] From ultrasonic thickness measurements.

[9] From PAUT report.

*This measurement was reported as part of the phased array UT inspection and is not conceivably consistent with the design wall thickness or other similar piping. Re-inspection of this location is recommended.

Table 6: Creep Life Assessment Piping Dimensions (inches)

Component	Specified Wall Thickness $t_{specified}$	Type of Specified Thickness	12.5% Under-Tolerance TOL	$t = t_{specified} - TOL$	Specified Outer Diameter D_o	Mean Diameter D_{mean}
Main Steam Piping	2.042	mean	0.255	1.787	13.375	11.588
	1.672	mean	0.209	1.463	10.750	9.287
	1.102	mean	0.138	0.964	8.52	7.551
	0.731	mean	0.091	0.640	4.500	3.860
	0.454	mean	0.057	0.397	2.375	1.978
Hot Reheat Piping	0.966	minimum	0.000	0.966	20.000	19.034
	0.826	mean	0.103	0.723	18.000	17.277
	0.914	mean	0.114	0.800	16.000	15.200
	0.438	mean	0.055	0.383	4.500	4.117
	0.281	mean	0.035	0.246	1.900	1.654
Cold Reheat Piping	0.840	minimum	0.000	0.840	24.015	23.175
	0.605	mean	0.076	0.529	16.000	15.471

Table 7: Design and MCR Conditions

Component	Design		MCR	
	P_{design} (psi)	T_{design} (°F)	P_{MCR} (psi)	T_{MCR} (°F)
Main Steam Piping	2070	1005	1890	1005
Hot Reheat Piping	618	1005	487	1005
Cold Reheat Piping	649	712	503	683

Table 8: Parametric Equations for Minimum Larson-Miller Parameters From Table F.31 of API 579-1/ASME FFS-1 [2].

Component	Material	Parametric Equations for LMP*
Main Steam Piping Hot Reheat Piping	SA-335-P22	$LMP^* = 1000\left[\frac{43.981719 - 40.4830050\sqrt{\sigma_{hoop}} + 15.37365\sigma_{hoop} + 0.66049429\sigma^{1.5}_{hoop}}{1.0 - 0.84656117\sqrt{\sigma_{hoop}} + 0.26236081\sigma_{hoop} + 0.049673781\sigma^{1.5}_{hoop}}\right]$
Cold Reheat Piping	SA-106-B	$LMP^* = 1000\,(40.588307 - 0.17712679\sigma_{hoop} - 2.6062117\ln\sigma_{hoop})$

*Factor of 1000 is not in Larson-Miller equation, but rather it is in the F-234 equation in API-579.
Units for σ_{hoop} are ksi.

Table 9: Predicted Life Fraction Expended (LFE) for Straight Piping Sections

Component	Specified Outer Diameter D_o (in)	Predicted LFE at End of 2009[9] (%)		Predicted LFE at End of Target Service Life (%)	
		LFE_{design}	LFE_{MCR}	LFE_{design}	LFE_{MCR}
Main Steam Piping	13.375	29.5	16.8	42.1	24.0
	10.750	25.2	14.3	35.9	20.4
	8.516	46.6	26.5	66.5	37.8
	4.500	18.4	10.5	26.2	15.0
	2.375	5.7	3.3	8.1	4.7
Hot Reheat Piping	20.000	15.7	3.7	22.4	5.3
	18.000	52.1	11.9	74.2	17.0
	16.000	12.6	3.0	17.9	4.3
	4.500	0.5	0.2	0.7	0.3
	1.900	0.1	< 0.1	0.1	< 0.1
Cold Reheat Piping	24.015	0.0	< 0.1	0.1	< 0.1
	16.000	0.1	< 0.1	0.2	< 0.1

Table 10: Predicted Life Fraction Expended (LFE) For Non-Straight Piping

Component	Specified Outer Diameter D_o (in)	Predicted LFE at End of 20099 (%)		Predicted LFE at End of Target Service Life (%)	
		LFE_{design}	LFE_{MCR}	LFE_{design}	LFE_{MCR}
Main Steam Piping	13.375	53.6	30.5	76.4	43.4
	10.750	45.5	25.8	64.8	36.8
	8.516	84.4	47.9	120.3	68.3
	4.500	33.2	18.9	47.4	26.9
	2.375	10.1	5.8	14.4	8.3
Hot Reheat Piping	20.000	28.3	6.6	40.4	9.4
	18.000	94.3	21.4	134.4	30.6
	16.000	22.7	5.3	32.3	7.5
	4.500	0.8	0.3	1.1	0.4
	1.900	0.1	< 0.1	0.2	< 0.1
Cold Reheat Piping	24.015	0.1	< 0.1	0.2	< 0.1
	16.000	0.3	< 0.1	0.4	< 0.1

[9] 2009 values included to provide a comparison to the calculations performed in the Level I assessment.

Appendix A: Flow Accelerated Corrosion

<table>
<tr><td colspan="2">1.0 FLOW ACCELERATED CORROSION ANALYSIS REPORT</td><td rowspan="2"></td></tr>
<tr><td colspan="2">Client: Holyrood TGS</td></tr>
<tr><td>Unit:</td><td>Systems:</td><td>Date:</td></tr>
<tr><td>2, 3</td><td>Feedwater (FW), Superheater Attemperator Station</td><td>November 13, 2014</td></tr>
<tr><td colspan="2">Operating Years:</td><td>AMEC NSS File Number:</td></tr>
<tr><td>Total:</td><td>Unit 2 - 43 years
(178,628 operating hrs as of May 2014 [4])
Unit 3 – 35 years
(139,821 operating hours as of May 2014 [4])</td><td rowspan="2">AM160/RP/001 R00</td></tr>
<tr><td>Since Last Inspection:</td><td>N/A</td></tr>
<tr><td>Inspection Method:</td><td>Inspection Procedure/Technique:</td><td>Inspection Date:</td></tr>
<tr><td>☒ Ultrasonic (U/T)</td><td></td><td>May 2014</td></tr>
<tr><td>☐ Pulse Eddy Current (Incotest)</td><td></td><td></td></tr>
<tr><td>☐ Radiography</td><td></td><td></td></tr>
<tr><td>☐ X-Ray Fluorescence (Material Testing)</td><td></td><td></td></tr>
<tr><td colspan="3">SCOPE (Locations and Component Summary):</td></tr>
</table>

All inspections identified in the 2014 AMEC NSS FAC work scope were completed [1]. All five (5) locations were inspected on Unit 3. One location on the Unit 2 feedwater system was inspected. It should be noted that the measurements were not necessarily recorded in the direction of flow, thus one must refer to the images of the inspected areas to confirm flow direction. Ultrasonic wall thickness measurements were performed at the following locations on the Feedwater system in Unit 2 and 3:

2-1: Full Flow Tee Downstream of High Pressure (HP) Heater No. 5

a) Tee (perpendicular pipe joint)
b) upstream pipe
c) downstream pipe

- (see 238-10-6022-022 R4, 238-10-0210-024 R1)

3-1: BFP Discharge: Pump 1 Discharge Piping, TW3553 and D/S Elbows

a) Piping immediately after Pump 1 nozzle
b) TW 3553 (take readings as close as possible around the circumference of the thermowell)
c) 1st Elbow
d) 2nd Elbow
e) Pipe D/S of HFW-V503

- (see 1403-340-M-003 R9, 1403-V-281-M-083)

3-2: BFP Discharge: Full Flow Tee D/S HP FW Heater 6

a) Double elbow, downstream of tee, tee and upstream of tee

- (see 1403-340-M-003 R9)

3-3: Attemperator Station

a) Pipes, elbows, reducers, and bypass line
- (see 1403-343-M-059 R0, 1403-V-281-M-083)

3-4: BFP Discharge: Low Flow Line Connection to Main Run

a) Low flow line elbow and pipe downstream of elbow
b) 10x4” concentric expander
c) Low flow tee
d) Main run elbow1 downstream of tee
- (see 1403-340-M-003 R9, 1403-V-281-M-083)

3-5: BFP Discharge: Elbow upstream of Economizer inlet

a) Elbow1 and downstream pipe to valve
- (see 1403-340-M-003 R9, 1403-V-281-M-083)

Details of the inspected locations and component geometries are provided in Table 1. Figures of areas of interest for each component are given in Appendix A.

RESULTS AND COMMENTS:

The following results were obtained by using the EPRI Band Method wall thinning assessment methodology, as documented in AMEC NSS FAC procedures [2]. The results are summarized in Table 1. The remaining life calculated in Table 1 is based on the minimum required wall thicknesses reported in the planned inspection scope [1], and the wear rate. The re-inspection intervals are identified as half the remaining life to accommodate for possible variations of wear rate, operating factors, water chemistry, etc. The end of life is assumed to be 2018 [4]. The units will be available on standby from 2018 to 2020 and are not expected to accumulate damage in this state. Permanent shutdown of the boiler and feedwater systems is planned in 2020.

The inspection locations, critical dimensions, calculated wear rates and recommended next inspection dates are listed in Table 1. The wall thickness profiles are compiled in Appendix A for areas of interest. ASME code required minimum wall thickness are used for all locations since they are high pressure piping systems.

In general, varying degrees of FAC damage are seen at all locations.

Locations Below Code Minimum Wall:

- Site No. 3-2: BFP Discharge: Full Flow Tee D/S HP FW Heater 6: weld overlay applied externally to the elbow before return to service.

Results and Recommendations:

- **Site No. 2-1 - Full Flow Tee Downstream of High Pressure (HP) Heater No. 5:** Wear rate analysis was performed using the UT data from the grid layout. The tee on this 10” pipe is composed of a pipe welded perpendicularly to another 10” pipe with a repad for reinforcement. The area of the reinforcing pad (repad) was not measured. All measured areas are above the ASME code calculated minimum wall. Both segments of this piping shows evidence of moderate wall loss due to FAC. Based on the calculated wear rate the next re-inspection is recommended in 6 years.
- **Site No. 3-1 - Pump 1 Discharge Piping:** Wear rate analysis was performed using the UT data from the grid layout. All locations are deemed fit for service for the planned 4 remaining years of operating life. In one band adjacent to the weld at the isolation valve, the recommended inspection time is fractionally less than 4 years. This is likely the counter-bore of the weld preparation and determining a wear rate for these types of locations is difficult. Re-inspection in 1 year is recommended to determine if a pad weld is necessary. Otherwise, the component is expected to remain operable until the end of life.
- **Site No. 3-2 - BFP Discharge: Full Flow Tee D/S HP FW Heater 6:** Wear rate analysis was performed

using the UT data from the grid layout. The data shows evidence of FAC in the upstream portion of the Tee indicating heavy use of the bypass line. Other locations upstream of this line may also have FAC damage that should be investigated.

A single wall thickness measurement (grid point I3) located on the intrados of the 2nd elbow has a reading of 0.980". The calculated minimum wall thickness is also 0.980". A repeat inspection using a smaller grid was used to confirm the reading. Using a ½" grid, two points with a wall thickness of 0.980" were found. The thinned section is highly localized and does not represent the typical evidence of FAC degradation. Regardless, remediation of the location was recommended. All other locations had a calculated re-inspection time greater than 4 years.

Note: A pad weld was used to build up the wall thickness in the area of the local wall thinning per the National Board Inspection Code (NBIC) guidelines. Re-inspection of the pad weld found thicknesses, in inches, of 1.069", 1.038", 1.1", 1.139" and 1.075". Using the minimum value of 1.038" in replace of the 0.980" from the original inspection finds a recommended re-inspection interval of 5 years, assuming the same rate of thinning. Therefore, the repaired elbow is expected to remain operable until the end of life.

- **Site No. 3-3 – Attemperator Station:** This component has multiple sections of 1", 2" or 3" piping. The Attemperator line also includes four valves (plus one valve each on the bypass line and drain line) and a number of reducers. According to the drawing, some parts of the attemperator station were replaced in 2010, giving only 4 years of operation since then. For the reducers/expanders the larger required wall thickness was used in the remaining time calculations. The wear rate analysis results indicate that all locations except for the bend prior to the block valve (rows 22 through 28) have calculated re-inspection times greater than 4 years. For the bend before the block valve at the inlet of the attemperators station, the lowest re-inspection time is 2 years. However milling variations in the wall thickness coupled with the low operating years may result in artificially high wear rates being calculated. A similar segment (90^o 3" bend after the last valve) indicates some wear but because this section was not replaced the years of operation reduce the wear rate and lead to at least 25 years before re-inspection is due. Therefore re-inspection of the area upstream of the block valve is recommend in 2 years to verify the wall loss rate.
- **Site No. 3-4 – BFP Discharge – Low Flow Line Connection to Main Run:** The low flow line is a 4" pipe which connects, via an expander, to a Tee on the main line, which is 10" in diameter and includes a 90^o bend. UT measurements were taken on the 4" and 10" pipe, the Tee, and the expander. The calculated wall thicknesses for the 10" and 4" sections were compared against the measurements. All areas were above the ASME code minimum wall thickness. The 10" minimum wall was conservatively applied to the expander. Some areas of reduced wall thickness were noted in the vertical run of the 10" pipe. The wear rate analysis found that the re-inspection time is marginally above 4 years. Therefore re-inspection is recommended in 4 years should the station plan to operate beyond May of 2018.
- **Site No. 3-5 – BFP Discharge – Elbow upstream of Economizer inlet:** The feedwater line to the economizer inlet is a 10" pipe with a 90^o bend that then connects to the economizer inlet link. The economizer inlet link is significantly thicker but was included in the FAC assessment for completeness. All areas of both the bend and the economizer link were above the ASME code minimum wall thickness. Some wall thinning is evident in the measurements on the internal extrados of the elbow. The calculated re-inspection time is 4 years or greater for all locations.

In summary, all of the 6 recommended locations were inspected. FAC damage is evident in varying degrees in all locations. One area had a wall thickness equal to the ASME code minimum wall thickness, and other locations found evidence of FAC wall thinning. The attemperator bend upstream of the block valve (1st valve in the station) should be re-inspected in 2 years to track the rate of wall loss and determine if a repair is necessary before the targeted end of life. The boiler feed pump discharge bend immediately before the isolation valve should be inspected in 1 year to verify the rate of wall loss at the counterbore and determine if a repair is necessary. In addition, utilisation and potential FAC in the HP FW Heater 6 by-pass line needs to be investigated. The remaining life of the other sites is expected to remain in good condition for the planned 4 years remaining for boiler and feedwater systems of the Holyrood Generating Station. Should plant life be extended beyond 4 years (2018), re-inspections for several components will be required.

References:

1. AM160/003/000001 R00 – "Copy of 2014 Detailed CA Work (Rev7) DM – May 5 2014.xlsx", May 5, 2014.
2. NSS00/PR/034 R01 – "Analysis Process for Flow Accelerated Corrosion based on UT Inspection Results", March 9, 2012.
3. Newfoundland and Labrador Hydro, Request for Proposals, "Condition Assessment and Life Extension Study, Phase II – Holyrood Thermal Generating Station", RFP 2014-57571, May 2014.
4. AM160/PL/001 R00 – "AM160 Project Work Plan", May 2014.

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Table 1 - Summary Table - Holyrood TGS Unit 3 Flow Accelerated Corrosion - 2014 Inspection Analysis

Base Data								Inspection Results					Inspection Status		
						Fabricated (")		Measured							
Location Description	**Site No.**	**Component**	**NPS (Inch)**	**70% of Nominal Thickness[3] (Inch)**	**ASME Minimum Wall (Inch)**	**Nominal Wall[5] (Inch)**	**Minimum Wall[6] (Inch)**	**t_{min} (Inch)**	**Band t_{max}[2] (Inch)**	**Maximum Wear[4] (Inch)**	**Band Wear rate[1] (Inch/yr)**	**Margin to Minimum Req'd Wall Thickness (Inch)**	**Potential Signs of FAC**	**Re-inspection time[7] (years)**	**Comments**
Full Flow Tee Downstream of High Pressure (HP) Heater No. 5	Site No. 2-1	North-South Pipe	10	-	0.980	1.125	-	1.052	1.184	0.132	0.003	0.072	Moderate	11.7	
		East-West Pipe	10	-	0.980	1.125	-	1.031	1.199	0.168	0.004	0.051	Moderate	6.5	
HP BFP – Pump 1 Discharge Piping	Site No. 3-1	Pipe	8	-	0.786	0.906	-	0.805	0.889	0.084	0.002	0.019	Minor	4.0	Possible counter-bore; low re-inspection time is from single band of data adjacent to a weld
		1st Elbow	8	-	0.786	0.906	-	0.829	0.943	0.114	0.003	0.043	Moderate	6.6	
		2nd Elbow	8	-	0.786	0.906	-	0.797	0.914	0.117	0.003	0.011	Moderate	1.6	Possible counter-bore; low re-inspection time is from single band of data adjacent to a weld
BFP Discharge: Full Flow Tee and Double Elbow at HP FW Heater 6 Exit	Site No. 3-2	Pipe D/S Tee (west side)	10	-	0.980	1.125	-	1.090	1.190	0.100	0.003	0.110	Minor	19.3	
		Tee	10	-	0.980	1.125	-	1.105	1.630	0.525	0.015	0.125	Significant	4.2	Possible counter-bore; low re-inspection time is from single band of data adjacent to a weld
		Pipe D/S Tee (east side)	10	-	0.980	1.125	-	1.109	1.220	0.111	0.003	0.129	Moderate	20.3	

Base Data								Inspection Results					Inspection Status		
						Fabricated (")		Measured							
Location Description	**Site No.**	**Component**	**NPS (Inch)**	**70% of Nominal Thickness[3] (Inch)**	**ASME Minimum Wall (Inch)**	**Nominal Wall[5] (Inch)**	**Minimum Wall[6] (Inch)**	**t_{min} (Inch)**	**Band t_{max}[2] (Inch)**	**Maximum Wear[4] (Inch)**	**Band Wear rate[1] (Inch/yr)**	**Margin to Minimum Req'd Wall Thickness (Inch)**	**Potential Signs of FAC**	**Re-inspection time[7] (years)**	**Comments**
		Pipe D/S Heater	10	-	0.980	1.125	-	1.080	1.140	0.060	0.002	0.100	Minor	29.2	
		1st Elbow	10	-	0.980	1.125	-	1.070	1.229	0.159	0.005	0.090	Moderate	9.9	
		2nd Elbow	10	-	0.980	1.125	-	0.980	1.198	0.218	0.006	0.000	Significant	0.0	Locally thinned area not consistent with expected FAC thinning profile.
		2nd Elbow (after repair)	10	-	0.980	1.125	-	1.038	1.198	0.160	0.006	0.058	NA – post repair	4.7	Pad weld repair. Same wear rate used.
HP FW Piping to Attemperator : West Valve Station and Bypass Line	Site No. 3-3	Pipe U/S Elbow	3	-	0.284	0.438	-	0.408	0.446	0.038	0.010	0.124	Minor	6.5	Piping installed in 2010. Any initial variation in wall thickness will contribute to artificially high wear rate and low re-inspection time.
		Elbow U/S Valve	3	-	0.284	0.438	-	0.426	0.548	0.122	0.031	0.142	Moderate	2.3	
		Pipe D/S Elbow	3	-	0.284	0.438	-	0.411	0.445	0.034	0.009	0.127	Minor	7.5	
		3x2" Reducer U/S Valve	3x2	-	0.284	0.438	-	0.432	0.481	0.049	0.012	0.148	Minor	6.1	
		3x2" Reducer D/S Valve	3x2	-	0.284	0.438	-	0.406	0.462	0.056	0.014	0.122	Minor	4.4	

Base Data								Inspection Results					Inspection Status		
						Fabricated (")		Measured							
Location Description	Site No.	Component	NPS (Inch)	70% of Nominal Thickness[3] (Inch)	ASME Minimum Wall (Inch)	Nominal Wall[5] (Inch)	Minimum Wall[6] (Inch)	t_{min} (Inch)	Band t_{max}[2] (Inch)	Maximum Wear[4] (Inch)	Band Wear rate[1] (Inch/yr)	Margin to Minimum Req'd Wall Thickness (Inch)	Potential Signs of FAC	Re-inspection time[7] (years)	Comments
		Pipe U/S Valve	3	-	0.284	0.438	-	0.398	0.440	0.042	0.011	0.114	Minor	5.4	
		Pipe D/S Valve	3	-	0.284	0.438	-	0.412	0.450	0.038	0.001	0.128	Minor	59.1	
		3x2" Reducer	3x2	-	0.284	0.438	-	0.416	0.468	0.052	0.001	0.132	Minor	44.5	
		Pipe U/S Valve	2	-	0.192	0.344	-	0.309	0.350	0.041	0.001	0.117	Minor	49.7	
		Pipe D/S Valve	2	-	0.192	0.344	-	0.333	0.360	0.027	0.001	0.141	Minor	91.1	
		Pipe D/S Tee Fitting	2	-	0.192	0.344	-	0.337	0.366	0.029	0.001	0.145	Minor	87.2	
		3x2 Reducer	3x2	-	0.284	0.438	-	0.433	0.520	0.087	0.002	0.149	Minor	30.0	
		Pipe D/S Valve	3	-	0.284	0.438	-	0.325	0.409	0.084	0.002	0.041	Minor	8.6	
		Pipe/Tee U/S Elbow	3	-	0.284	0.438	-	0.339	0.408	0.069	0.002	0.055	Minor	14.0	
		Elbow	3	-	0.284	0.438	-	0.483	0.619	0.136	0.004	0.199	Moderate	25.6	
		Pipe D/S Elbow	3	-	0.284	0.438	-	0.405	0.454	0.049	0.001	0.121	Minor	43.3	

Base Data								Inspection Results					Inspection Status		
						Fabricated (")		Measured							
Location Description	**Site No.**	**Component**	**NPS (Inch)**	**70% of Nominal Thickness[3] (Inch)**	**ASME Minimum Wall (Inch)**	**Nominal Wall[5] (Inch)**	**Minimum Wall[6] (Inch)**	**t_{min} (Inch)**	**Band t_{max}[2] (Inch)**	**Maximum Wear[4] (Inch)**	**Band Wear rate[1] (Inch/yr)**	**Margin to Minimum Req'd Wall Thickness (Inch)**	**Potential Signs of FAC**	**Re-inspection time[7] (years)**	**Comments**
		Pipe D/S of Tee from 3" pipe	1	-	0.107	0.25	-	0.232	0.258	0.026	0.007	0.125	Minor	9.6	Piping installed in 2010. Any initial variation in wall thickness will contribute to artificially high wear rate and low re-inspection time.
		Pipe D/S of elbow	1	-	0.107	0.25	-	0.239	0.268	0.029	0.007	0.132	Minor	9.1	
		Pipe D/S of Valve	1	-	0.107	0.25	-	0.230	0.267	0.037	0.001	0.123	Minor	58.4	
		Pipe D/S of Elbow	1	-	0.107	0.25	-	0.248	0.266	0.018	0.001	0.141	Minor	137.5	
		Drain Pipe D/S of Tee	1	-	0.107	0.25	-	0.220	0.237	0.017	0.004	0.113	Minor	13.3	
		Drain Pipe D/S of Elbow	1	-	0.107	0.25	-	0.223	0.238	0.015	0.004	0.116	Minor	15.5	
HP BFP Discharge - Low Flow Line Connection to Main Run	Site No. 3-4	Tee	10	-	0.980	1.125	-	1.211	1.460	0.249	0.007	0.231	Significant	16.2	Possible counter-bore; low re-inspection time is from single band of data adjacent to a weld
		Elbow	10	-	0.980	1.125	-	1.032	1.158	0.126	0.004	0.052	Moderate	7.2	Possible counter-bore; low re-inspection time is from single band of data adjacent to a weld
		Pipe D/S Elbow	10	-	0.980	1.125	-	1.014	1.161	0.147	0.004	0.034	Moderate	4.0	Areas of reduced wall thickness noted in vertical 10" pipe

Base Data								Inspection Results					Inspection Status		
						Fabricated (")		Measured							
Location Description	**Site No.**	**Component**	**NPS (Inch)**	**70% of Nominal Thickness[3] (Inch)**	**ASME Minimum Wall (Inch)**	**Nominal Wall[5] (Inch)**	**Minimum Wall[6] (Inch)**	**t_{min} (Inch)**	**Band t_{max}[2] (Inch)**	**Maximum Wear[4] (Inch)**	**Band Wear rate[1] (Inch/yr)**	**Margin to Minimum Req'd Wall Thickness (Inch)**	**Potential Signs of FAC**	**Re-inspection time[7] (years)**	**Comments**
		4x10 Reducer	10	-	0.980	1.125	-	1.633	1.804	0.171	0.005	0.653	Moderate	66.8	
		Pipe U/S Reducer	4	-	0.410	0.531	-	0.475	0.520	0.045	0.001	0.065	Minor	25.2	
HP BFP Discharge - Elbow upstream of Economizer Inlet	Site No. 3-5	Elbow	10	-	0.980	1.125	-	1.050	1.300	0.250	0.007	0.070	Significant	4.9	Wear seen on the extrados of the pipe bend.
		Pipe D/S Elbow	10	-	0.980	1.125	-	1.890	2.031	0.141	0.004	0.910	Moderate	112.9	

1 Based on 35 years of service for Unit 3 and 43 years of service for Unit 2.

2 Band refers to the circumferential band of which t_{min} is located.

3 70% of nominal wall is used for low pressure piping to avoid possible leakage or burst in situations where the ASME min wall is very low.

4 This column represents band wear.

5 This column represents nominal wall thickness corresponding to the pipe schedule, or assumed pipe schedule if not directly available.

6 This column represents minimum wall thickness corresponding to the piping and insulation schedule.

7 The re-inspection time is based on margin above the required minimum wall thickness, except for repaired or previously repaired locations.

FAC	Maximum Wear
Significant	>0.200" between max and min
Moderate	0.100" - 0.200" between max and min
Minor	0.000" - 0.100" between max and min

Appendix E: Hot Reheat Combine Stop Valve Hanger Failures

WAYLAND ENGINEERING LTD.

FAILURE INVESTIGATION OF HOLYROOD #3 REHEAT PIPE HANGERS

SEPTEMBER, 2014

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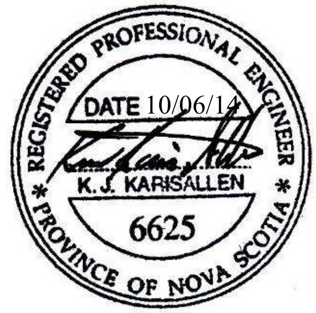

Report No: 1434-A
Date: October 6, 2014

1.0 Background

Wayland Engineering Ltd. was asked by Newfoundland Hydro (NH) to conduct an investigation on two (2) pipe hangers removed from the reheat line of Unit #3 at the Holyrood generating station. The hangers were removed from service as the result of the detection of fracture failures of the components (Figure 1) during a scheduled outage inspection [1]. It has been indicated that fracture failures were observed in both the east and west pipe hangers during the inspection [1]. It was reported that the hangers had been in service since 1980 with approximately 140,000 cumulative operating hours prior to removal [1].

The function of the hangers was to provide vertical support for the 16 inch reheat line pipes and the combined stop valves [1]. The east hanger supported the inlet side of the combined stop valve 3-HR-V512 on line 3-HR-L500, whereas the west hanger supported the inlet side of the combined stop valve 3-HR-V513 on line 3-HR-L501 [1]. During normal operation, the pipes associated with the hangers contained superheated steam at a temperature of approximately 1000 ^{o}F [1]. Each hanger consisted of two sides configured in a pipe clamp arrangement. The sides of the hanger were mechanically fastened to each other at the top and bottom clamp tabs resulting in a friction fit between the pipe and the semicircular clamp surfaces. A clevis rod arrangement was utilized to attach the upper tab of the hanger to a support structure located above the line. It has been indicated that the pipe (including the hanger) was insulated with a layer of refractory material to minimize heat loss during operation [1]. The specification for the hanger material was reported as ASTM A387, Grade 12 [1]. Newfoundland Hydro requested that Wayland Engineering provide an opinion on the mechanism(s) responsible for the fracture failures detected on the hangers.

Figure 1 - Photograph showing the general pipe hanger arrangement. Arrows indicate one of the hanger fracture failures observed during a scheduled inspection.

2.0 Preliminary Examination

Figure 2 through Figure 4 show photographs of the sections of the east and west pipe hangers as received for analysis. The sections consisted of curved, 5.75 inch wide by 0.875 inch thick plate coupons. Deposits were observed on the exterior surfaces of the coupons which were comprised of a combination of high temperature oxides and refractory insulating materials. Inspection of the exterior surface did not reveal evidence of significant loss of structural hanger material owing to a corrosion mechanism. Figure 5 and Figure 6 show side and end views of the typical fracture surfaces observed on the hangers. The general orientation of the fracture plane associated with the failed hangers was observed to be approximately orthogonal to the longitudinal axis of the components. In general, the morphology of the fracture surface consisted of a relatively planar surface with an irregular topography. Similar to the exterior surface of the hangers, a deposit including high temperature oxides was typically observed on the fracture surfaces of the respective hangers.

Detailed elemental chemical analyses were conducted for the hanger materials received. The results of the analyses conducted have been summarized in Table 1. For both hangers, the results indicated that with the exception of Si and Cr (which were higher than the allowable limits), the material was in general chemical conformance with an ASTM A387, Grade 12 specification. Hardness testing of the hanger east and west hanger materials indicated bulk hardness ranges of approximately 192 - 220 HB and 200 - 208 HB, respectively.

Table 1 – Results of the chemical analyses conducted for the pipe hanger materials.

	Chemical Composition (wt%)													
	C	Mn	P	S	Si	Cr	Ni	Mo	V	Cu	Sn	Sb	As	B
East Hanger	0.14	0.61	<0.010	<0.005	0.74	1.22	0.05	0.57	<0.01	0.02	<0.01	<0.01	<0.01	<0.001
West Hanger	0.14	0.61	<0.010	<0.005	0.75	1.22	0.05	0.56	<0.01	0.02	<0.01	<0.01	<0.01	<0.001
ASTM A387, Grade 12 Specification	0.05-0.17	0.40–0.65	0.025 max	0.025 max	0.15-0.40	0.80-1.15	—	0.45-0.60	—	—	—	—	—	—

Figure 2– Photograph showing the sections of the east reheat pipe hanger as received for analysis.

Figure 3 - Photograph showing the sections of the west reheat pipe hanger as received for analysis.

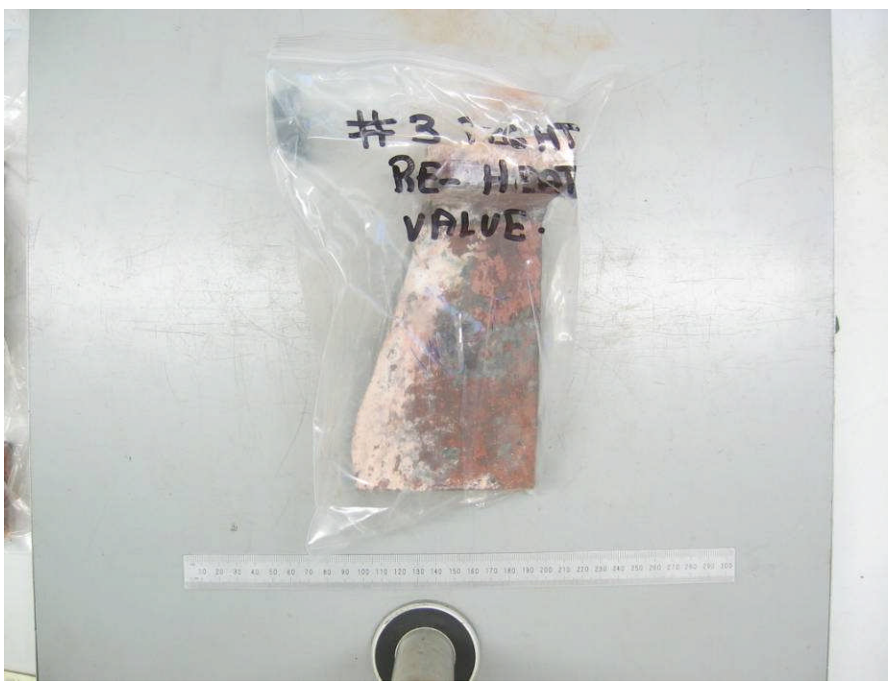

Figure 4 - Photograph showing an additional section of the west reheat pipe hanger as received for analysis.

Figure 5 - Photograph showing a side view of the fracture failure of one of the east sections of pipe hanger.

Figure 6 - Photograph showing the fracture surface associated with the east section of pipe hanger shown in Figure 5.

3.0 Metallurgical Examination

Several sections were removed from the hanger coupons and prepared for metallographic analysis using light microscopy. Figure 7 and Figure 8 show micrographs of the typical microstructures observed for the east and west hanger materials, respectively. The microstructures associated with both hangers examined provided evidence of spheroidization of the pearlite colonies and migration of carbides to the grain boundaries. Both spheroidization and migration of carbides to the grain boundaries are consistent with that expected for an ASTM A387, Grade 12 material subjected to extended service within the temperature range reported.

Figure 9 shows a typical sectional view micrograph of the material adjacent to the fracture surface associated with the pipe hanger indications. The indications were characterized by an intergranular crack propagation mechanism. In addition, limited lateral cracking emanating from the primary propagation path was observed for the samples examined. Of relevance to the current investigation was the absence of significant void formation (associated with a creep damage mechanism) in the material adjacent to the fracture plane. Figure 9 also shows the deposits typically observed on the fracture surfaces. To determine the composition and distribution of the elements associated with the fracture surface deposits, the material was subjected to a scanning electron microscope (SEM) energy dispersive X-ray (EDAX) analysis. Figure 10 shows a sectional view SEM backscatter (compositional) image of a typical fracture surface including deposits. Table 2 and Figure 11 show the general composition of the deposits and the EDAX maps for the elements detected within the deposit. The semi-quantitative EDAX results (Table 2) indicated that the deposit was comprised primarily of Fe and O with lesser amounts of Cr, Mo, Mn, and Si. The composition of the deposits together with the deposit morphology observed was consistent with the oxide generated on exposed surfaces during the elevated temperature associated with operation (i.e. magnetite).

SEM fractographic imaging was also conducted to determine the topology associated with the crack propagation mechanism. Figure 12 is a fractographic image showing the predominantly intergranular fracture topology observed previously (Figure 9). Evidence of transgranular cleavage was also observed on the fracture surface. Of note is the relatively large grain size in comparison to the spheroidized ferrite/pearlite microstructure shown in Figure 7 and Figure 8 which suggests that the intergranular fracture observed in Figure 12 was not associated with the ferrite/pearlite grain boundaries. Figure 13 is a micrograph showing the presence of microfissures observed in the material away from the primary crack propagation path. The micrograph suggests that the crack propagation observed proceeded along prior austenitic grain boundaries.

Given the intergranular nature of the crack propagation mechanism combined with the operating temperature reported, one possible mechanism for the indications observed includes temper embrittlement. From a mechanical properties perspective, the embrittlement generated by a temper embrittlement mechanism is reversible in the absence of micro-fissuring [2]. To ascertain the presence of temper embrittlement, mechanical testing combined with selective heat treatments were conducted. The specimen design employed for the mechanical testing was a bend bar with cross-sectional dimensions of 10mm x 10 mm and a length of approximately 55 mm. The surface orthogonal to the outer surface of the pipe hanger was notched to a depth of 2 mm. The orientation of the notch was positioned to force a crack propagation path similar to that observed in the pipe hangers received for analysis. The specimens were subjected to three-point bending using a dynamic loading rate at a temperature of approximately 20 ^{o}C. Subsequent to testing, the fracture surfaces associated with all the specimens were inspected using binocular microscopy. Selected specimens were also subjected to a fractographic analysis using SEM imaging.

Figure 14 shows a fractograph of the crack propagation plane for the as received pipe hanger material loaded at a dynamic rate. The morphology indicates that the propagation mechanism is dominated by a combination of intergranular fracture and transgranular cleavage. It should be noted that while transgranular cleavage may result from crack tip constraint conditions, the presence of intergranular fracture is atypical of an A387, Grade 12 material in its as manufactured state. Figure 15 shows a fractograph of the crack propagation plane for material heat treated at 1200 ^{o}F and loaded at a dynamic rate. A temperature of 1200 ^{o}F was selected because it should reverse the processes associated with temper embrittlement and as such eliminate the intergranular component of the fracture morphology observed in the as received specimen tests [2]. In comparison to the as received material test, the morphology of the heat treated fracture plane indicates that the propagation mechanism is dominated by a combination of transgranular cleavage and void coalescence. The change in propagation mechanism suggests that a reversible embrittlement mechanism was responsible for the fracture observed in the pipe hangers.

Table 2 – Semi-quantitative SEM EDAX elemental analysis results for the fracture surface deposits (point A1 in Figure 10).

	Chemical Composition (wt%)					
	Fe	O	Cr	Mo	Mn	Si
Point A1	77.61	22.21	0.18	ND	ND	ND

Note: ND indicates that the element was not detected.

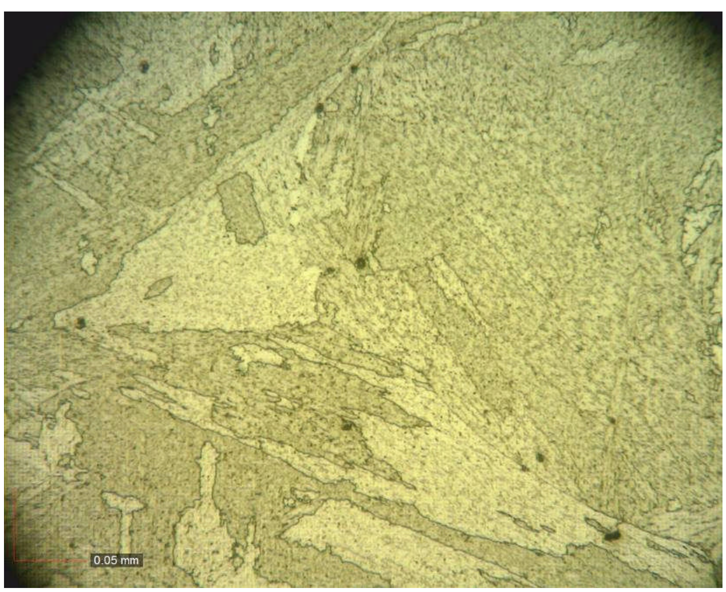

Figure 7 – Micrograph showing the spheroidized microstructure and the migration of the spheroidized carbides to the grain boundaries for the east hanger.

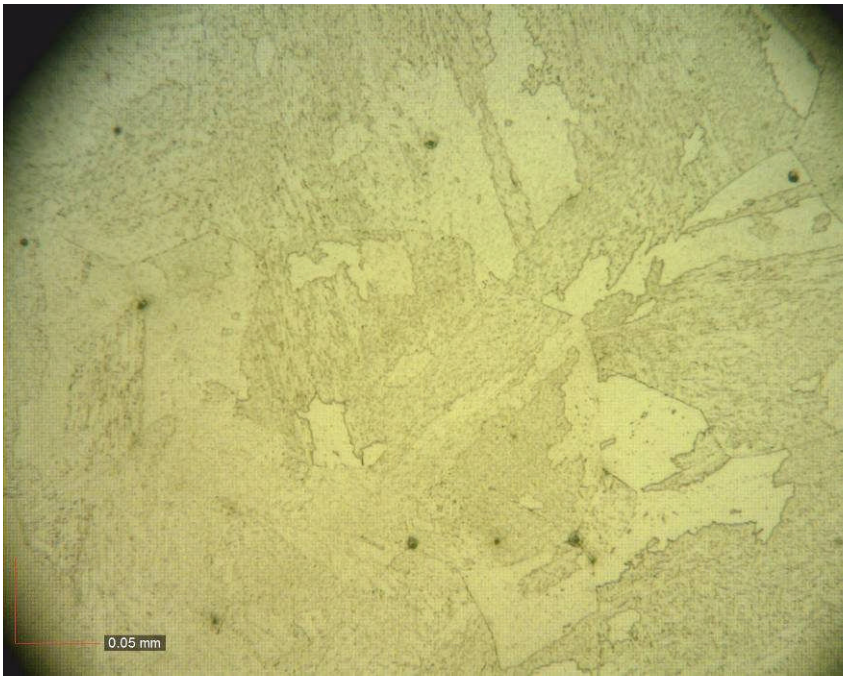

Figure 8 – Micrograph showing the spheroidized microstructure and the migration of the spheroidized carbides to the grain boundaries for the east hanger.

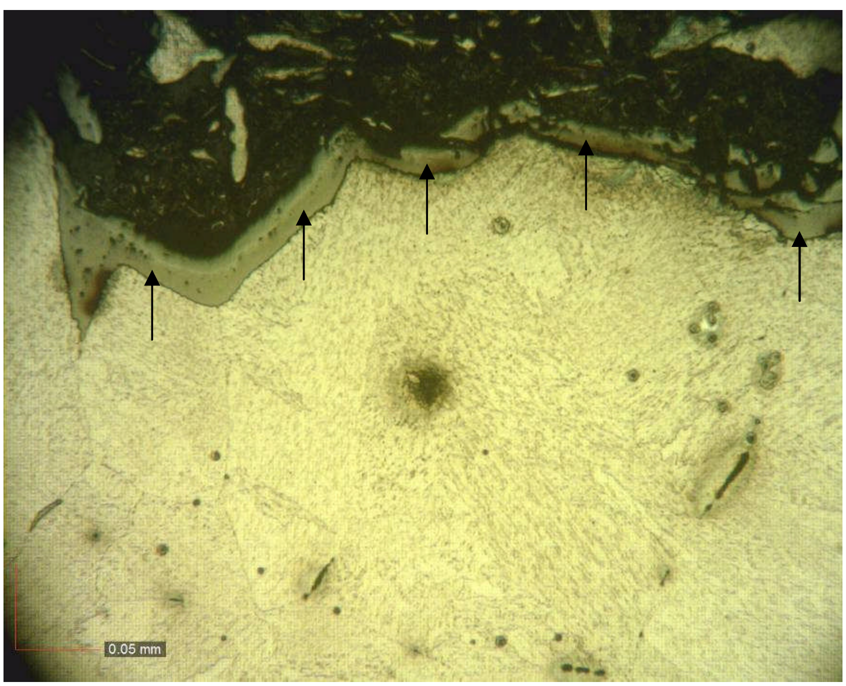

Figure 9 – Sectional view micrograph of the material adjacent to the fracture surface associated with the pipe hanger indications. The micrograph also shows the deposits typically observed on the fracture surfaces (arrows).

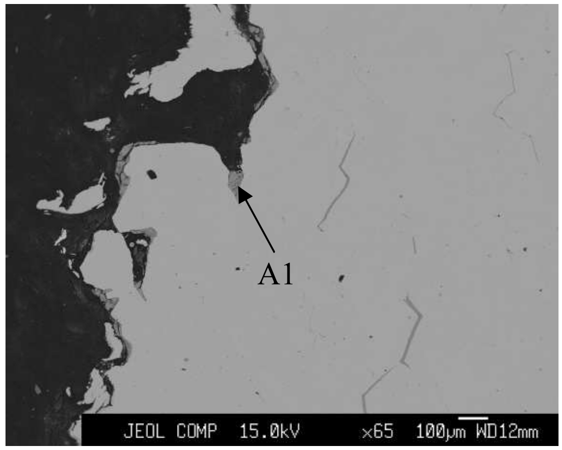

Figure 10 – Sectional view SEM backscatter image of the material adjacent to the fracture surface of an indication.

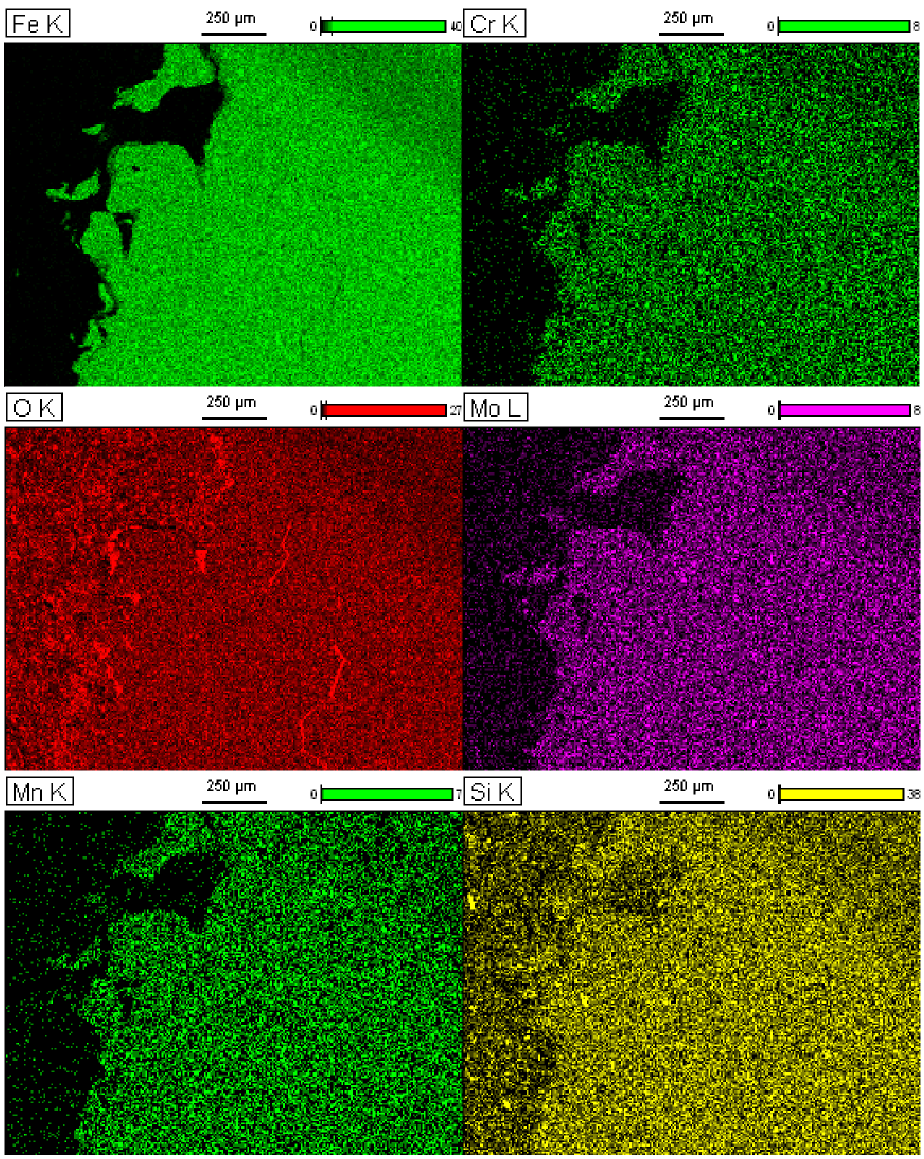

Figure 11 –SEM EDAX maps (Fe, Cr, O, Mo, Mn, and Si) for the area shown by the SEM image in Figure 10.

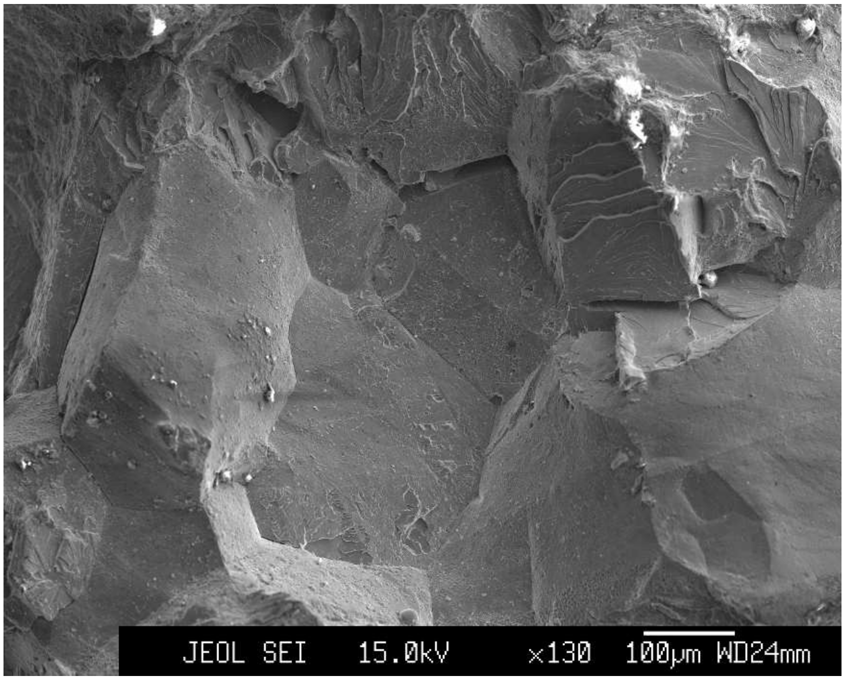

Figure 12 – SEM fractograph image showing the predominantly intergranular fracture topology observed (evidence of transgranular cleavage was also observed on the fracture surface). Of note is the relatively large grain size in comparison to the spheroidized ferrite/pearlite microstructure shown in Figure 7 and Figure 8.

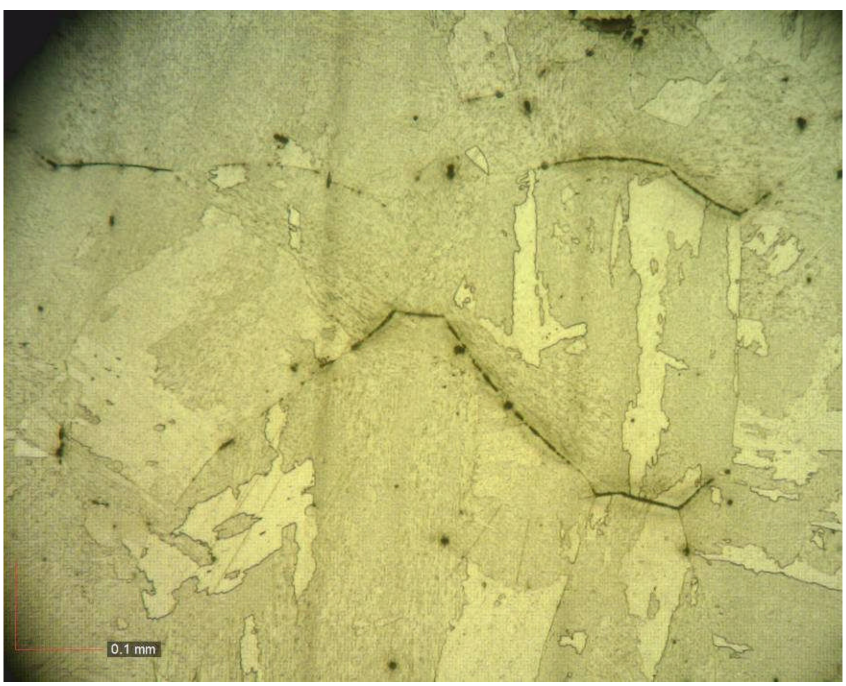

Figure 13 – Sectional view micrograph showing the presence of microfissures observed in the material away from the primary crack propagation path. The micrograph suggests that the crack propagation observed proceeded along prior austenitic grain boundaries.

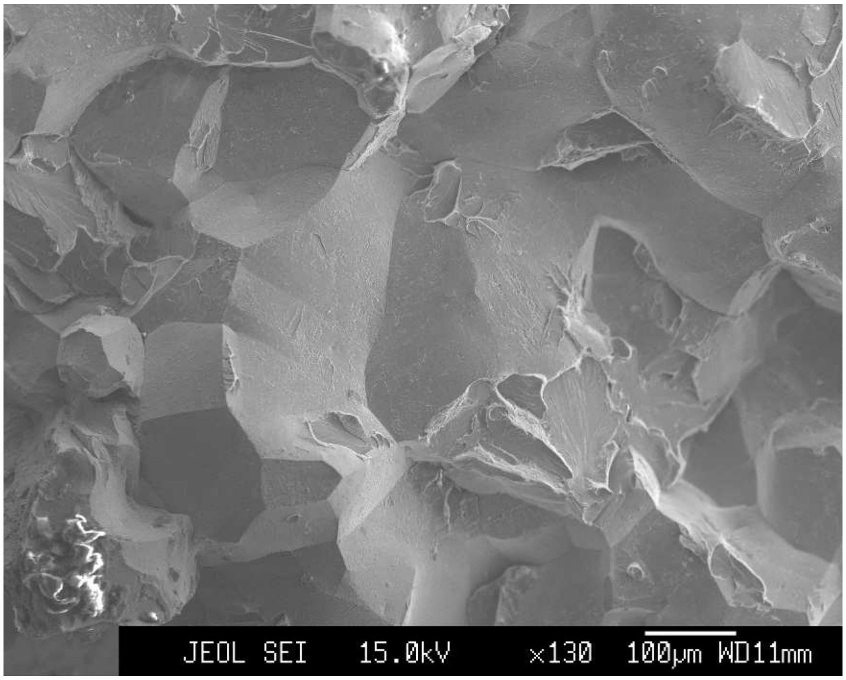

Figure 14 – SEM fractograph of the crack propagation plane for the as received pipe hanger material loaded at a dynamic rate. The morphology indicates that the propagation mechanism is dominated by a combination of intergranular fracture and transgranular cleavage.

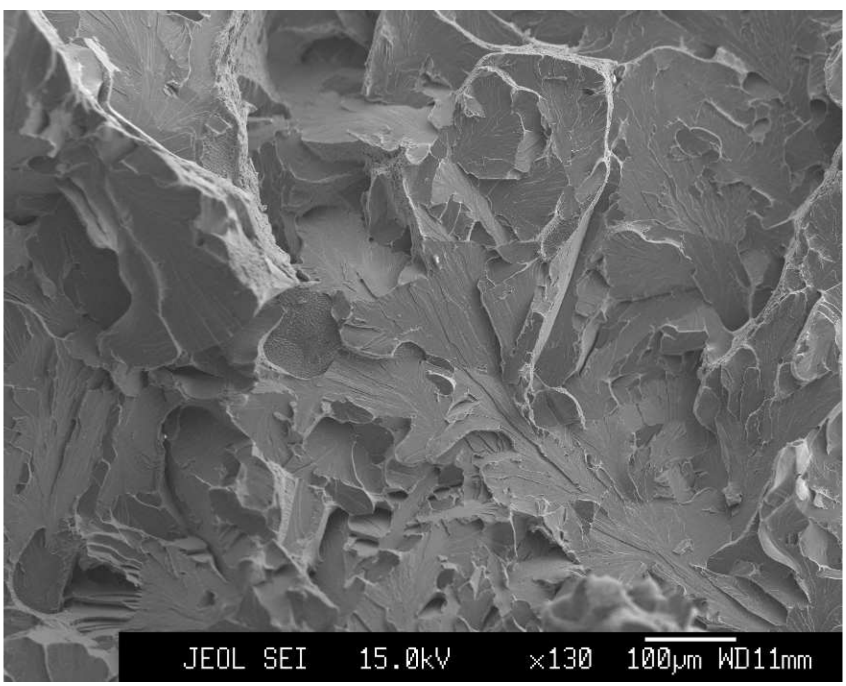

Figure 15 – SEM fractograph of the crack propagation plane for material heat treated at 1200 ^{o}F and loaded at a dynamic rate. In comparison to the as received material test (Figure 14), the morphology of the heat treated fracture plane indicates that the propagation mechanism is dominated by a combination of transgranular cleavage and void coalescence.

4.0 Discussion and Conclusions

The physical and microstructural evidence indicates that the mechanism responsible for the indication observed in the Holyrood Unit #3 reheater pipe hangers submitted for analysis is consistent with the initiation and propagation of cracking within the material due to an embrittlement mechanism. The intergranular morphology of the propagation observed for the indications together with the presence of microfissures propagating along prior austenitic grain boundaries in the material adjacent to the primary fracture plane supports a temper embrittlement failure mechanism. In addition, the change in propagation mechanism from an intergranular mode (in the as received material) to a transgranular cleavage/void coalescence mode (in the as received material heat treated at 1200 ^{o}F) suggests a reversible mechanism which is also consistent with temper embrittlement. The presence of high temperature oxides observed on the fracture surfaces received suggests that the surfaces experienced a prolonged exposure to a high temperature environment (during operation of the unit) prior to detection of the indications during the recent outage inspection.

Temper embrittlement may occur in low alloy steel materials subjected to long term exposure within the temperature range between approximately 650 ^{o}F and 1100 ^{o}F. Prolonged exposure to temperatures within the range results in the segregation of impurities contained in the material to the prior austenitic grain boundaries. Material impurity elements responsible for temper embrittlement include phosphorus (P), tin (Sn), arsenic (As) and antimony (Sb). Materials elements which are known to further facilitate the segregation of the impurities to the grain boundaries include manganese (Mn), silicon (Si), nickel (Ni), and chromium (Cr). The net effect of temper embrittlement is an increase in the ductile to brittle transition temperature associated with the material. The shift in the transition temperature may result in relatively low toughness in the pipe hanger material during periods of unit inactivity. The reduction in toughness results in a corresponding reduction in the material stress required to initiate and propagate a crack in the component. Temper embrittlement may also result in a lowering of the fatigue resistance of the of a material leading to increased crack propagation rates in components subjected to cyclic stress (e.g. thermal cycling of the unit).

Methods of reducing the potential of temper embrittlement in the component include utilizing a steel material with a low level of impurities in the composition together with a Si and a Cr content within the specified ranges (Table 1) or utilizing a structural material which is not susceptible to a temper embrittlement mechanism over the operational temperature range associated with the component (such as AISI 321 or AISI 347 stainless steel). An alternative method of reducing the potential for temper embrittlement in the material is the redesign of the hanger component such that the hanger resides outside the layer of insulation (reduce the material temperature below the temperature range associated with embrittlement). Given the current configuration of the hanger assembly, a redesign of the component may prove impractical. The potential effects (i.e. cracking) of an embrittled material may also be reduced by ensuring that scenarios which lead to higher than normal mean and cyclic stresses in the hanger components are minimized.

5.0 References

[1] Various E-Mails Provided by J. Curtis, Newfoundland Hydro, September 2014.
[2] ASM Metals Handbook, Volume 11, American Society for Metals, Metals Park, Ohio, 1986

Amec Foster Wheeler Confidential

Holyrood Level II Condition Assessment Follow-up Inspections - 2015

BW016/RP/003 R00

December 24, 2015

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Revision Summary

Rev	Date	Author	Comments
R00	December 2015	T. Ogundimu	Initial Issue.

Certification Statement

I, the undersigned, being a licensed professional engineer in the province of Ontario and being competent in the applicable field, have prepared or directly supervised the preparation of this document, following the procedures of the Amec Foster Wheeler quality management system.

Amec Foster Wheeler document and revision no. BW016/RP/003 R00

Certified by: Dave McNabb

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Stamp

Date: 24 December 2015

EXECUTIVE SUMMARY

Considering the age of the units, HTGS boilers and piping are in good condition. There is no significant inspection scope remaining from the condition assessment. Continued monitoring is recommended in specific areas to ensure damage does not accumulate for the remaining few years of planned operation.

The current assessments only consider operation to 2018.

The major recommendations from the 2015 inspection results are:

1. Complete additional inspections on feedwater piping for FAC.
2. Perform a PAUT inspection of the seam weld in the Unit 2 SH6.
3. Improve procedures and update instrumentation to avoid thermal transients and prevent further ligament cracking in the economiser inlet headers.

Regular operation beyond 2018 will require an overall life-management plan, particularly for the high temperature components that can experience accelerated creep, and the feedwater piping which experiences FAC.

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1.0 BACKGROUND

Nalcor Energy (the owner of HYDRO) requires that the Holyrood Thermal Generating Station (HTGS) continue to operate as a generating station under current operating patterns to 2018, as standby until 2021 and for Unit 3, as a synchronous condensing facility until 2041. Operation to these dates will result in life extension beyond the original design of the station. Level I [1] and Level II [2][3] Condition Assessments were performed to confirm potential degradation problems and estimate remaining life. The Condition Assessment scope was concluded in 2014 with recommendations being generated for capital reinvestment, surveillance tasks and additional inspections to confirm findings.

The 2015 inspection scope was based on the recommendations from the previous inspection reports and the recommended Level II Condition Assessment inspection scope for the boilers and high-energy piping. Assessment of the 2015 inspection results was required to identify components and/or systems, which required remedial measures (repair, repeat inspection, and/or analysis) to allow the station to continue to operate with high reliability during the extended operating period.

The following is a summary of the 2015 inspection campaign results. The conclusions and recommendations are developed within the context of the three units seeing little or no generation production operation beyond 2018. The conclusion and recommendations also assume the units will continue to be operated within specified design parameters.

1.1 Objective

This work follows-up on the recommendations of the Level II Condition Assessments which commenced from 2012 to 2014 [2][3]. Although the project for the Level II study has been closed, the utility continues to follow recommendations from previous work and complete higher priority Condition Assessment inspections that were not done previously. Follow-up work for life management and flow accelerated corrosion (FAC) was also done. On-going condition monitoring and repair tasks are recommended.

1.2 Scope

The scope of work is based on the recommendations given in the condition assessment reports [2][3].

The inspection and assessment scope was divided into four areas

- Inspection follow-up - for areas noted in previous assessments as requiring subsequent inspection to confirm or track degradation.
- Unit 3 Economizer Inlet Header Assessment - thermal fatigue damage was found in the header in 2014. A follow-up inspection was requested to determine the size of the cracks, damage accumulation rates and remaining life.

- Flow Accelerated Corrosion - locations were recommended for follow-up, to track or confirm degradation, from previous scope documents and from inspection reports.
- Operations Assessment - staff interviews, operating data and operating procedure reviews to determine potential impacts on off-line corrosion and thermal fatigue.

2.0 NDE RESULTS AND RECOMMENDATIONS

The NDE findings and recommendations for each inspected location are provided in Table 1. Locations with a grey background do not require any further assessment in the planned remaining life (end of 2018). For components with a 3 year re-inspection period, re-inspection is not required unless there is continued operation beyond 2018.

The FAC inspection results are taken from the analysis report [6].

The NDE reports are also provided in the reference binder [4].

Table 1 Results and Recommendations Summary

	Component/Location	Inspection	Findings	Recommendations
Unit 1	Feedwater - BFP Discharge: Economizer Inlet Header Piping	UT Grid for Flow Accelerated Corrosion	All locations were above the minimum wall thickness. One area adjacent to a weld found a band of low wall thicknesses.	Re-inspection recommended in 1 year to confirm the wall loss rate, unless weld build up is used to increase the wall thickness.
	Feedwater - BFP Discharge: Flow Element 554	UT Grid for Flow Accelerated Corrosion	All locations were above the minimum wall thickness though some areas are near the minimum.	Re-inspection recommended in 1 year unless weld build up is used to increase the wall thickness.
	Feedwater - BFP Discharge: West Pump Discharge Elbow and Reducer	UT Grid for Flow Accelerated Corrosion	One point was below the pressure based ASME minimum wall thickness, and other low areas were found adjacent to the inlet weld of the reducer (on the 8" diameter side). Weld buildup was completed to increase the wall thickness. The re-inspection time will depend on the as-left wall thickness.	Measure the as-left wall thickness to determine the re-inspection time.
	Feedwater - Low Pressure Elbow Upstream of Deaerator	UT Grid for Flow Accelerated Corrosion	All locations were above the minimum wall thickness (70% of nominal wall thickness for low pressure piping). An unusual variation in the wall thickness was observed; this may be FAC but it is not an integrity concern.	Re-inspection is recommended in 8 years
	Feedwater - BFP Discharge: East Attemperator Station	UT Grid for Flow Accelerated Corrosion	All locations were above the calculated pressure based ASME minimum wall thickness. On the reducer immediately upstream of the inlet control valve, one band showed a large variation in the wall thickness and thus a higher wall loss rate. The date of installation of the attemperator piping could not be confirmed, thus there is some uncertainty in the wear rate and re-inspection time.	The installation date for the piping needs be confirmed. Re-inspection is recommended in 6 years.
	Feedwater - BFP Recirculation East: U/S and D/S of FV 544	UT Grid for Flow Accelerated Corrosion	All points were well above the calculated pressure based ASME minimum wall thickness.	Re-inspection is recommended in 21 years.

	Component/Location	Inspection	Findings	Recommendations
	SH6 Outlet Nozzles (East and West)	Phased Array Ultrasonic Testing (PAUT), Magnetic Particle Inspection (MPI), Metallographic Replication	In 2013 [2], creep damage was reported at the toe of weld on the east nozzle. The damage was removed and weld repaired. MPI only was performed on the west nozzle; no damage was found. In 2015, a small crack was found at the bottom of the east nozzle weld (~3 mm in length), about 20 mm from the previous repair. No microscopic creep damage was observed in the replicas. Replicas were taken at the bottom (6 o'clock position) of both nozzle welds. Microstructure showed spherical carbide particles in a matrix of ferrite grains. Assuming the original microstructure consisted of pearlite and ferrite, this microstructural transformation is not unexpected for the age of the component. PAUT found no mid-wall creep crack development. MPI inspection of the full circumference of the nozzles did not find any indications.	This is likely an original fabrication weld defect that was not removed previously. Since volumetric inspection found no evidence of cracking, inspections can return to the recommended 3 year inspection interval [2], alternating between Units 1 and 2 (for an overall 6 year inspection interval on each unit). The entire surface of the weld should be ground smooth, to improve the sensitivity of MPI.
Unit 2	Feedwater - BFP Discharge: Full Flow Tee D/S HP FW Heater 6	UT Grid for Flow Accelerated Corrosion	All measured areas are above the ASME code calculated minimum wall. The region shows evidence of moderate wall loss due to FAC.	Based on the calculated wear rate the next re-inspection is recommended in 5 years.
	Feedwater - BFP Discharge: Pump 1 (West) Discharge Piping	UT Grid for Flow Accelerated Corrosion	All measured areas are above the ASME code calculated minimum wall. All segments of this piping show moderate evidence of wall loss due to FAC	Based on the calculated wear rate the next re-inspection is recommended in 8 years.
	Feedwater - BFP Discharge: East Attemperator Station	UT Grid for Flow Accelerated Corrosion	All measured areas are above the ASME code calculated minimum wall. The apparent difference in the margin upstream of the valve is still evident.	Re-inspection is recommended in 14 years.
	Lower Vestibule Feeder Tubes	Phased Array Ultrasonic Testing (PAUT)	Inspection was conducted on six (6) bends. No fatigue crack or other degradation was found.	No further inspection is required for this component.
	RH2	Metallographic Macro-Etch	A longitudinal weld on the south side of the header was confirmed.	No further inspection is required for this component at this time. If the recommended PAUT inspection of the SH6 header seam weld finds

	Component/Location	Inspection	Findings	Recommendations
				damage, the RH2 seam should also be inspected.
	Boiler Stop Valve Inlet Weld	Phased Array Ultrasonic Testing (PAUT), Magnetic Particle Inspection, Metallographic Replication	PAUT found no evidence of mid-wall creep cracking. Replicas found no visible evidence of creep damage. Microstructure showed small, spherical carbide evenly distributed in ferrite matrix; this is not unexpected given the operating hours on the unit.	Since there was no creep damage detected, no further inspection of this weld is necessary.
	MS West Turbine Terminal	Phased Array Ultrasonic Testing (PAUT), Magnetic Particle Inspection, Metallographic Replication	Replicas found no visible evidence of creep damage. Microstructure showed small, spherical carbide evenly distributed in ferrite matrix; this is not unexpected given the operating hours on the unit. PAUT found no evidence of mid-wall creep crack development	No further inspection of this location is necessary.

	Component/Location	Inspection	Findings	Recommendations
	SH-6 Nozzle East/West	Phased Array Ultrasonic Testing (PAUT), Magnetic Particle Inspection, Metallographic Replication	In 2012, multiple cracks were identified by MT in the weld on the east and west nozzles [2]. The cracks were believed to be original fabrication defects. The majority of the damage was removed by grinding but small micro-cracks (not visible with MT) remained. A weld repair was applied to the bottom of the east nozzle to restore the wall thickness. In 2015, small cracks (intergranular and disjointed, ~2.5mm in length) were observed on the bottom of both the east and west nozzle welds. In the east nozzle, cracks were oriented in the weld material near the header fusion line. In the west nozzle, cracks were oriented within the heat affected zone (HAZ). The cracks were ground out; subsequent MPI found no reportable indications. PAUT found no evidence of mid-wall creep crack development. A longitudinal weld was located on the west end of the header, on the north side. Replication was performed 2 m inboard from the west end. No evidence of surface cracking or creep damage was found.	The observed cracks are likely to be fabrication damage that was not removed during the previous repair. Since volumetric inspection found no evidence of cracking, inspections can return to the recommended 3 year inspection interval [2], alternating between Units 1 and 2 (for an overall 6 year inspection interval on each unit). The entire surface of the weld should be ground smooth, to improve the sensitivity of MPI. PAUT of the seam weld to look for sub-surface creep damage is recommended in the next outage.
	Steam Drum East-most Downcomer	Wet Fluorescent Testing	The inspection found no Indications.	Periodic inspection should continue: one end (one downcomer) every 3 years, alternating ends for both Units 1 and 2.
Unit 3	Feedwater - BFP Discharge: HP Heater No. 6 Bypass	UT Grid for Flow Accelerated Corrosion	Initial inspection found one measurement below the minimum wall thickness on an elbow. Re-inspection with a finer grid found several locations below the minimum. The elbow was replaced. FAC is evident in the bypass line.	Re-inspection is recommended in 3 years.
	Feedwater - BFP Discharge: Full Flow Tee D/S HP FW Heater No. 6 and Bypass Tee Connection	UT Grid for Flow Accelerated Corrosion	Evidence of FAC was seen in the wall thickness data for the discharge bends, the tee and the bypass piping. There are a few thinned areas and a few isolated low points but they are all above the minimum required wall thickness.	Re-inspection is recommended in 3 years.

	Component/Location	Inspection	Findings	Recommendations
	Feedwater - BFP Discharge Piping Eccentric Reducer and Y	UT Grid for Flow Accelerated Corrosion	The inspected piping shows evidence of FAC. One area had a measurement below the calculated minimum wall thickness. Three other areas had insufficient wall thickness for remaining life. Most of the low measurements were immediately adjacent to a weld so there is likely an effect of the counterbore contributing to the observed wall thinning. Weld repairs were applied.	Measure the as-left wall thickness to determine the re-inspection time.
	Feedwater - Low Pressure (LP) Feedwater Flow Element	UT Grid for Flow Accelerated Corrosion	The measurements show evidence of FAC but all the measurements were above the minimum.	Re-inspection is recommended in 21 years.
	Feedwater - BFP Discharge: Bend U/S of Heater 5 Inlet	UT Grid for Flow Accelerated Corrosion	All measured areas are above the minimum wall thickness. Both segments of this piping show evidence of wall loss due to FAC.	Re-inspection is recommended in 4 years.
	Economizer Inlet Header	Remote Visual	Inspection found the same cross ligament borehole cracking that was seen in 2014.	Re-inspect visually in 3 years, and complete a sample crack depth measurement with PAUT. Mitigate occurrence of thermal transients. See reference [5] for more details.
	Lower Vestibule Waterwall Feeder Tubes	Phased Array Ultrasonic Testing (PAUT)	PAUT of 10 tubes found no crack. Isolated pitting was noted in one tube. Average wall thickness was 11.4 mm; wall thickness at the pit was 10.4 mm.	A visual inspection of the inside diameter of the pitted feeder tube is requested to determine if the pitting is active (i.e. if orange corrosion products are visible).
	Main Steam East Boiler Link	Ultrasonic Testing (UT)	The minimum measured wall thickness (1.553) are greater than the minimum wall thickness (1.230").	No further inspection is required for this location.
	Cold Reheat Bleed Steam Line	Magnetic Particle Inspection	The inspection found no Indications.	No further inspection is required for this location.

3.0 ANALYSIS

In addition to the recommendations specific to the locations inspected in 2015, the next sections provide additional recommendations for continued inspections.

3.1 Feedwater Piping

Flow Accelerated Corrosion (FAC) is the most concerning failure mechanism for the feedwater piping. Review of the measurement profiles found that FAC is active in most locations on the feedwater system. In the 2015 inspections, 3 locations were below the calculated ASME minimum wall thickness and others were near the minimum [6]. For some locations, the combination of weld counterbore and FAC wall loss resulted in measurements that were near or below the minimum wall, which necessitated repairs.

Weld repairs were conducted using a combination of NBIC and ASME accepted practices. The NBIC [7] allows for repairs to thinned areas by external weld build-up over no more than 25% of the pipe circumference. For some locations weld build-up on more than 25% of the circumference was required, so a repair procedure was prepared using additional ASME accepted practice [8]. However, the jurisdictional authority has since requested that all repairs be compliant with NBIC. Those components repaired using a process exceeding NBIC limitations will be replaced.

Locations below minimum wall can be dispositioned through analysis, however repair in accordance with NBIC or replacements can often be less expensive, avoid near term re-inspection costs, and are more likely to be accepted by the regulator.

It should also be noted that evidence of FAC was identified in the low pressure feedwater system. Although the inspected locations do not present an integrity concern, the results indicate that the low pressure side can experience FAC, and needs to be considered in any long term FAC management program.

If target life is extended beyond summer 2018 additional inspections will be required, as there are a number of components with re-inspections that should occur in 2018, or in the following years. This scope can be determined from review of the re-inspection times of the tables of 2012, 2014 and 2015 FAC inspection reports [9][10] and [6].

Based on the information collected, FAC is evident to various degrees on all three units at HTGS. The focus has been on the high pressure piping and main low pressure piping. FAC is also likely in the feedwater heater drains and vents, and in the heater shells, including the deaerators. It is understood that the feedwater heater drain and vents, and deaerators are addressed under separate programs, and the feedwater heater shells are not likely to have accumulated significant damage, as many have been replaced.

Future FAC inspections need to address locations previously identified as having a limited life, and similar locations on other units. From review of the FAC inspection reports and HTGS feedwater drawings, additional new locations (**bolded**) have been included in the FAC inspection scope in Table 2 for the period up to 2018. This includes areas with weld repairs that the regulator wants replaced. If operation is anticipated beyond 2018 a scope review is required. Table 2 also includes the locations inspected in 2015 requiring near-term follow-up, for completeness.

Table 2 FAC Results and Recommendations Summary

Unit	Location	Time to (Re-)Inspection
1	Economizer Inlet Header Piping	1 year (unless weld build up applied)
	Flow Element 554	1 year (unless weld build up applied)
	West Pump Discharge Elbow and Reducer	Measure the as-left wall thickness to determine the re-inspection time.
	Heater No. 6 bypass	**1 year (if history suggests past use)**
	East boiler feed pump discharge piping and wye	**1 year**
2	**Heater No. 6 bypass**	**1 year (if history suggests past use)**
	Economiser inlet header inlet bends	**1 year**
	East and West boiler feed pump discharge piping, bends and wye	**1 year**
	Flow Element 554	**1 years**
3	HP Heater No. 6 Bypass	3 years
	Full Flow Tee D/S HP FW Heater No. 6 and Bypass Tee Connection	3 years
	BFP Discharge Piping, Eccentric Reducer and Y	Measure the as-left wall thickness to determine the re-inspection time.
	Flow Element 554	**1 year**

The final wall thicknesses of the weld repairs performed in 2015 should be reviewed too determine the next re-inspection time, but they should be re-inspected in no later than 3 years to ensure there is no damage initiating as a result of the weld process.

3.2 Unit 3 Economizer Inlet Header

A review of the Unit 3 2015 economizer inlet header inspection results has been documented in reference [5]. The Unit 3 economizer inlet header is fit-for-service but needs to be re-inspected within 3 years. This assumes that the current operating pattern (approximately 8 starts per year [4]) is maintained over the next 3 years.

The next inspection of the Unit 3 economizer inlet header should include phased array ultrasonic testing (PAUT) of a sample ligament crack to characterize the depth and profile of the ligament cracking. Alternatively, if the borehole ligaments cannot be inspected, perform inspections at ligaments between the boiler-fill connection and thermowell penetrations at the inlet.

It is recommended that the occurrence and severity of thermal transients in the economizer inlet header be reduced. To do this:

- The through-wall temperature difference instrumentation on the header should be made operational. The instrumentation is required for compliance with the boiler insurer, as per procedure POP-136, or final feedwater temperature be confirmed available to the control room operator as a real time feedback on occurrence and causes of thermal transients.
- Refine operating procedures to minimise thermal transients.
- Update and demonstrate operating procedures for boiler starts and boiler steam drum top-ups to include direct reference to trickle feeding of feedwater to the boiler.

If there is anticipation of continued operation beyond 2018, completion of fracture mechanics, and stress analyses prior to the next inspection of the Unit 3 economizer inlet header can be beneficial for reducing conservatism in the end of life estimate.

3.3 High Temperature Component Inspections

Inspections for high temperature creep damage were performed on steam headers and piping. No microscopic creep damage was seen. The nozzles of the SH6 in both Unit 1 and 2 were inspected with MPI, PAUT and surface microstructure replication. MPI and PAUT found no surface, mid-wall or ID indications, however replication found cracking in both nozzles on Unit 2 and the east nozzle in Unit 1.

Longitudinal seam welds were identified on both the SH6 and RH2 headers. Replication of the SH6 long seam weld found no evidence of creep damage.

The Unit 2 main steam west turbine terminal was re-inspected by MPI, PAUT and replication. No evidence of creep damage was found. This result indicates the earlier concern over early stage creep at this location was not valid. Similar inspections on the Unit 2 Boiler Stop Valve inlet weld confirmed no creep damage.

Wall thickness measurements on the steam piping has confirmed acceptable wall thicknesses relative to design.

Although these components appear to be in good condition, operation beyond 2018 will require a life-management plan to ensure degradation is monitored. By the end of 2018 it is anticipated Units 1 and 2 will approach the calculated creep life limit of 250,000 hours for the main steam turbine terminal piping [3]. Re-inspection of the high temperature headers and piping will need to be considered if regular operation continues beyond 2018.

3.4 Low Temperature Boiler Component Inspections

A number of inspections were conducted by PAUT or radiography (RT) to investigate the occurrence of pitting and corrosion fatigue cracking. There was no evidence of corrosion fatigue cracking in the Unit 3 waterwalls tubing or in the riser and feeder piping on Units 2 and 3.

Off-line corrosion pitting was previously identified in riser piping is considered benign. A similar concern was identified in the Unit 3 feeder piping. The depth was identified as 1mm. This is not considered an immediate concern but needs to be monitored if the unit sees regular operation beyond 2018.

4.0 CONCLUSION

Considering the age of the units, HTGS boilers and piping are in good condition. The original Condition Assessment scope is given in Appendix A, with the inspections completed in 2015 included. There is no significant inspection scope remaining from the condition assessment, however continued monitoring is recommended in specific areas to ensure damage does not accumulate for the remaining few years of planned operation.

The current assessments only considers operation to 2018. Regular operation beyond 2018 will require additional inspections to ensure continued fitness for service.

5.0 RECOMMENDATIONS

The major recommendations are:

1. Additional inspections are recommended for several feedwater locations for FAC.
2. PAUT inspection of the seam weld in the Unit 2 SH6 is recommended to ensure no subsurface damage is present.
3. Procedural refinement and instrumentation upgrades are recommended to avoid thermal transients and prevent further ligament cracking in the economiser inlet headers. This is more important for Unit 3 but would also be beneficial for Units 1 and 2. Additional inspection and analysis work can be performed if temperatures cannot be controlled.

Regular operation beyond 2018 will require an overall life-management plan, particularly for the high temperature components that can experience accelerated creep, and the feedwater piping which experiences FAC.

6.0 REFERENCES

[1] T. Mahmood, T. Ogundimu, "HTGS Condition Assessment and Life Extension Study", File No. AM060/RP/001 R01, January 2015.

[2] D. McNabb, "Holyrood Thermal Generating Station Condition Assessment and Life Extension Study –Phase 2, 2012/13 Level II Condition Assessment Boiler and High-Energy Piping", AMEC NSS Report: AM132/RP/005 R03, November 2013.

[3] T. Ogundimu, "2014 Level II Condition Assessment Boiler and Steam Piping, Flow Accelerated Corrosion, Units 1 and 3 Generators, Civil Structures", File No. AM160/RP/002 R01, December 5, 2014.

[4] NDE Reference Binder, File No. BW016/RE/006 R00, December 24, 2015.

[5] D. McNabb, "Holyrood TGS Unit 3 Economizer Inlet Header Cracking – 2015 Investigation", File No. BW016/004/000001 R00, December 2, 2015.

[6] T. Ogundimu, "Flow Accelerated Corrosion Analysis Report", File No. BW016/RP/002 R00, November 6, 2015.

[7] National Board of Boiler and Pressure Vessel Inspectors, "National Board Inspection Code 07 - Part 3 Repairs and Alterations".

[8] G. Poon, "External Weld Metal Buildup Procedure- Holyrood GS Feedwater Piping, Line# 3-HFW-09-L502", File No. BW016/005/000001 R01, October 26, 2015.

[9] B. Dobbie, "Holyrood Thermal Generating Station Flow Accelerated Corrosion (FAC) Feedwater and Condensate Piping Inspection Scope for Stage I & II 2012 Outages", File No. AM132/RP/001 R02, October, 2012.

[10] T. Ogundimu, "Unit 3 FAC Report", File No. AM160/RP/001 R00, November 13, 2014.

Appendix A: Holyrood TGS Level II Condition Assessment – NDE Scope[1]

Sub-component	Issue	Locations for Inspection	NDE Method						NDE Comment	Comments Findings
			MT	UT	Replica	PAUT[2]	RT	Visual		
Unit 1 and 2 Boiler										
Waterwall tubes	• ID Corrosion Fatigue cracking	Cold side attachments • Top of burner Cor 2 • Buckstay corner Elev 59'-10' Cor 1 • Buckstay cor at Rear wall, elev 64'-10", cor 3 • Side wall/ slope at buckstay, elev 26'-11" west wall					X		RT from outside of boiler (film on boiler interior)	No indications of ID cracking
Waterwall Risers (penthouse)	• ID Corr Fatigue at neutral axis of bends	Sample of 10 risers identified by inspection • Bends for cracking		X				X	• Boroscope from inside drum for ID cracking in neutral axis (90º & 270º)	
	• Oxygen pitting	• Horizontal sections for pitting					X		• Pitting in horizontal sections (sagging) • RT for pitting	
	• OD Fatigue at nozzles		X						• External MT at drum weld	
Boiler Drum	• General fitness • Thermal fatigue cracking	General visual of drum internal for major damage (remove internals and baffles)						X	• General visual •	Only cyclones removed No unusual indications
		Riser and sat steam nozzles at drum ID	X					X	• 3 sections, about 10% each, selected during general visual inspection	U1 inspected , no damage found

[1] Shaded areas identify inspections completed in 2012 to 2015. Details are contained in the reference reports.
[2] PAUT = Focused Phased Array and TOFT/Linear Phased Array

Sub-component	Issue	Locations for Inspection	NDE Method						NDE Comment	Comments Findings
			MT	UT	Replica	PAUT[2]	RT	Visual		
									• Internal visual of risers (boroscope)	
		Seam welds (sample sections)	X						• 1m section of lower and upper axial seam alternative between courses • 1m sections of circ welds including T, top and bottom , alternating between courses	Upper Seam weld
		Downcomer penetrations	X						Inaccessible internal areas Inside drum	Thermal fatigue cracking found at all four downcomers
		Drum Head Penetrations and Shell	X	X					• MT of penetrations • UT wall thickness of shell and heads	Part of annual survey Minor findings consistent with previous inspections.
		Boroscope ID of safety valve internal						X	Boroscope of nozzle ID to exterior of drum	NR no damage at other nozzles
Downcomer	Thermal fatigue on ID	Downcomer to H1 header nozzle welds		X		X		X	Boroscope inspection of H1 ID Linear PUAT of 2 dwncr to H1	ID Visual inspection complete
		Downcomer to steam drum nozzle welds	X					X	50% from inside drum (2 downcomers) Inspect weld 0.5m down from Drum ID	**2015**: East-most downcomer on unit 2. No indications.
	Fatigue on OD	Header Support Welds (50%)	X							NR Low Priority. No evidence to support fatigue damage
Ec Inlet Hdr	• Corrosion fatigue (circ) cracking in stub tubes • Thermal fatigue on ID of header • FAC in header or stub tubes	Inlet Hdr stub tubes First, last and middle 5 tubes (15 total)		X		X			Shear wave (PAUT) on tubes for circ ID cracking & thickness measurement	
		Inlet header (post-cleaning)				X		X	UT as required to size defects Boroscope on ID	ID boroscope inspection in 2014. Found borehole corner cracking and evidence of FAC. Pad welds required for continued operation.
SH4	• Thermal fatigue	Inspect Girth weld	X	X	X	X		X	1 circ weld	NR Low Priority on Life Fraction Assessment

Sub-component	**Issue**	**Locations for Inspection**	**NDE Method**						**NDE Comment**	**Comments** **Findings**
			MT	UT	Replica	PAUT[2]	RT	Visual		
	cracking on the ID								UT – Thickness Linear PAUT of weld Focused PAUT as required, at least one replica	
	• Creep in weld	Visual inspection of ID, for macro cracking						X	Boroscope of ID	NR high remaining life from Level I assessment
Link Piping	• Creep in seam weld	Piping downstream of attemperator Penthouse access needed may require type 3 asbestos abatement.	X	X	X	X			Etch 2 pipes to assess if seam welded If seam welded, inspect seam (50%) Liner PAUT and Focused PAUT if anomalies found, replica and wall thick	
Main steam header (SH6)	Creep/ Creep Fatigue	Header thickness		X					Measure between circ welds	Access and cleaning of Header and supports
		Header ID visual						X	Boroscope of ID (ligaments, drain, nozzle)	Remove hand-hole cap No relevant indications. Findings supported by inspection in 2010
		Header girth welds (50%) At least one weld without a nozzle – to be confirmed on dwgs	X		X	X			Thickness + Linear PAUT of weld +1 replica – more if anomalies found	Low priority due to construction – only girth welds are external to boiler. Main concern is nozzle welds
		Header head seam welds (50%)	X		X	X			3 sections of hdr comprising 50% of length – etch if necessary to locate Lear PAUT of target length Focused PAUT of anomalies + 3 sample locations	**2015**: full circumferential etch completed on Unit 2 and seam weld located. Replica found no evidence of creep.
		Header outlet nozzle welds (50% - 1 nozzle)	X	X	X	X			Thickness + Linear PAUT of weld +1 replica – more if anomalies found	**2015**: cracking found after preparation for replicas was complete on Unit 2. Small crack found on Unit 1 east nozzle.
		Header supports (50%)	X							

Sub-component	Issue	Locations for Inspection	NDE Method						NDE Comment	Comments Findings
			MT	UT	Replica	PAUT[2]	RT	Visual		
	Thermal fatigue	Drain (also seem to act as a vent. Inspect at weld to hdr in hdr vestibule)	X						External welds Interior thermal fatigue should be evident from boroscope inspection	NR Low priority
CRH Header	Thermal fatigue	CRH Header Internals						X	Boroscope ID through handhole cap	No relevant indications identified
HRH Header	Update creep life estimate	Header thickness		X					Between circ welds	
	Creep/ Creep Fatigue	HRH Header Internal						X	Boroscope	No indications identified
		Header Supports (50%)	X							No indications identified
		Header Girth Welds (50%)	X		X	X			Thickness + Linear PAUT of weld +1 replica – more if anomalies found	No indications Replication not completed
		Header Seam Welds (50%) PAUT as req'd to size indications	X	X	X	X			3 sections of hdr comprising 50% of length – etch if necessary to locate Linear PAUT of target length Focused PAUT of anomalies + 3 sample locations at least 1 replica	Partial etch completed. No weld identified. **2015**: Full circ etch completed; seam weld located.
		Header outlet nozzle welds (%50)	X	X	X	X			Thickness + Linear PAUT of weld +1 replica – more if anomalies found	East nozzle inspected. No indications identified Replication not completed
Reheat Tubes	Creep-type damage in Dissimilar Metal Weld	Remove two dissimilar metal welds from Reheat outlet bank							Destructive metallurgical analysis	Tubes containing welds to be replaced due to ID off-line corrosion
Unit 3 Boiler										
Penthouse Riser Tubes	Corrosion fatigue in neutral axis of bend	Inspect select short radius bends				X			10 risers at bends, 1' section, selected by inspection and RT for pitting	NR No evidence of movement causing fatigue

Sub-component	**Issue**	**Locations for Inspection**	**NDE Method**						**NDE Comment**	**Comments Findings**
			MT	UT	Replica	PAUT[2]	RT	Visual		
									External MT at drum weld	
	Oxygen Pitting	Inspect sample horizontal sections					X		Sample feeders to be selected by inspection – look for ID pitting in lower half of feeder	
	Fatigue	Inspect sample nozzle welds at steam drum	X						10 riser nozzles – same feeders as selected for bend inspection	
Lower Downcomer Header	Thermal fatigue at bore holes	One header (east or west)		X				X	Wall thickness and internal boroscope	
Lower WW Header	Thermal fatigue	One header internal visual inspection at bore holes and at flat end plug weld		X				X	Wall thickness and internal boroscope.	
Unit 1 Main Steam Piping										
West Boiler Link	Creep & Creep Fatigue	• Girth Weld • Thermowell • Gamma plug	X	X	X	X		X	MT on Gamma plug and thermowell MT, PAUT, UT, Replica on girth weld	
Shop Weld Above Stop Valve	Creep & Creep Fatigue	• Shop Weld above BSV • Instrument penetrations	X	X	X	X		X	MT on Gamma plug and thermowell MT, PAUT, UT, Replica on girth weld	
Boiler Stop Valve Inlet weld	Creep & Creep Fatigue	• Boiler Stop Valve, upstream weld • Gamma plug • Hanger lugs • Drain	X	X	X	X		X	MT on Gamma plug hanger lug, drain and thermowell MT, PAUT, UT, Replica on girth weld	
Main Stop Valve Inlet	Creep & Creep Fatigue	• Girth Weld • Drain & Gamma plug	X	X	X	X		X	MT on Gamma plug and drain MT, PAUT, UT, Replica on girth weld	Low Priority

Sub-component	Issue	Locations for Inspection	NDE Method						NDE Comment	Comments Findings
			MT	UT	Replica	PAUT[2]	RT	Visual		
East Turbine Gov Valve Terminal	Creep & Creep Fatigue	• Flange Weld	X	X	X	X		X	MT, PAUT, UT, Replica on girth weld	Not a flange
Unit 1 Hot Reheat Piping										
West Boiler Link	Creep & Creep Fatigue	• Girth Weld • Thermo Well • Gamma plug	X	X	X	X		X	MT on Gamma plug and thermowell MT, PAUT, UT, Replica on girth weld	
Lower Y Inlet	Creep & Creep Fatigue	• Girth Weld • Hanger lugs • Gamma plug	X	X	X	X		X	MT on Gamma plug and thermowell MT, PAUT, UT, Replica on girth weld	Thickness data is required
East CSV Inlet	Creep & Creep Fatigue	• Girth Weld • Drain	X	X	X	X		X	MT on drain MT, PAUT, UT, Replica on girth weld	
East Turb Terminal	Creep & Creep Fatigue	• Flange Weld (Under Turbine)	X	X	X	X		X	MT, PAUT, UT, Replica on girth weld	
Unit 1 Cold Reheat Piping										
West Boiler Link	Fatigue	• Girth Weld OD and ID	X	X		X		X	MT, UT and PAUT on Weld Looking for ID fatigue cracking	
Lower Y Inlet, & Hanger Lug	Fatigue	• Girth Weld • Hanger Lug above Y	X	X		X		X	MT, UT and PAUT on Weld, MT on lug	
West Turbine Terminal	Fatigue	• Flange Weld	X	X		X		X	MT, UT and PAUT on Weld Looking for ID fatigue cracking	NR
Unit 2 Main Steam Piping										
East Boiler Link	Creep & Creep Fatigue	• Girth Weld • Thermowell • Gamma plug	X	X	X	X		X	MT on Gamma plug and thermowell	No evidence of creep voids

Sub-component	Issue	Locations for Inspection	NDE Method						NDE Comment	Comments Findings
			MT	UT	Replica	PAUT[2]	RT	Visual		
									MT, PAUT, UT, Replica on girth weld	
Upper Y East Side	Creep & Creep Fatigue	• Upper Y East Inlet Weld • Crotch of Y • East Hanger Lug • Gamma plug	X	X	X	X		X	MT on Gamma plug and thermowell MT, PAUT, UT, Replica on girth weld, and Y crotch	NR No damage in U1
West Main Stop Valve Outlet	Creep & Creep Fatigue	• Girth Weld • Gamma plug •	X	X	X	X		X	MT on Gamma plug MT, PAUT, UT, Replica on girth weld	East MSV Outlet Nozzle completed on Unit 1 in 2013
West Turb Gov Valve Terminal	Creep & Creep Fatigue	• Flange Weld	X	X	X	X		X	MT, PAUT, UT, Replica on girth weld	**2015**: From previous inspection Possible Isolated creep voids in HAZ (Type III). Repeat replication in 2015 did not find evidence of creep.
Unit 2 Hot Reheat Piping										
East Boiler Link	Creep & Creep Fatigue	• Girth Weld • Thermowell • Gamma plug	X	X	X	X		X	MT on Gamma plug and thermowell MT, PAUT, UT, Replica on girth weld	No evidence of creep voids
Upper Y East Leg and Crotch	Creep & Creep & Creep Fatigue	• Upper Y east weld and crotch • Hanger lug – east side • Gamma plug	X	X	X	X		X	MT on Gamma plug MT, PAUT, UT, Replica on girth weld, and Y crotch	No evidence of creep voids
West CSV Outlet	Creep & Creep Fatigue	• Girth Weld	X	X	X	X		X	MT, PAUT, UT, Replica on girth weld	West CSV Outlet Nozzle Weld completed on Unit 1 in 2013 Thickness data is required
Unit 2 Cold Reheat Piping										
East Boiler Link	Fatigue	• Girth Weld	X	X		X		X	MT, UT and PAUT on Weld Looking for ID fatigue cracking	No Evidence of Damage

Sub-component	**Issue**	**Locations for Inspection**	**NDE Method**						**NDE Comment**	**Comments Findings**
			MT	UT	Replica	PAUT[2]	RT	Visual		
Htr 6 Bleed Steam Nozzle	Fatigue	• Htr 6 Bleed Steam Nozzle Weld	X	X		X		X	MT, UT and PAUT on Weld Looking for ID fatigue cracking	**2015**: MPI found not indications.
East Turbine Terminal	Fatigue	• Flange Weld	X	X		X		X	MT, UT and PAUT on Weld Looking for ID fatigue cracking	NR
Unit 3 Main Steam Piping										
West Boiler Link	Creep & Creep Fatigue	• Girth Weld • Gamma plug	X	X	X	X		X	MT on Gamma plug MT, PAUT, UT, Replica on girth weld,	
Upper Y and BSV	Creep & Creep Fatigue	• Boiler Stop Valve outlet • Upper Y West Leg and crotch • Hanger Lugs • Drain & Gamma plug	X	X	X	X		X	MT on Gamma plug, drain and lug MT, PAUT, UT, Replica on girth weld, and Y crotch	
West Main BSV Inlet	Creep & Creep Fatigue	• West Main Stop Valve Inlet • Gamma plug • Drain • Thermowell + Press Tap	X	X	X	X		X	MT on Gamma plug, drain & inst connections MT, PAUT, UT, Replica on girth weld, and Y crotch	
West Boiler Terminal Above Turb deck at flange	Creep & Creep Fatigue	• Flange Weld	X	X	X	X		X	MT, PAUT, UT, Replica on girth weld	
Unit 3 Hot Reheat Piping										
West Boiler Link	Creep & Creep Fatigue	• Girth Weld • Gamma Plug	X	X	X	X		X		
Lower Y Inlet	Creep & Creep Fatigue	• Girth Weld • Hanger lugs • Gamma plug	X	X	X	X		X		

Sub-component	**Issue**	**Locations for Inspection**	**NDE Method**						**NDE Comment**	**Comments Findings**
			MT	UT	Replica	PAUT[2]	RT	Visual		
West CSV Inlet	Creep & Creep Fatigue	• Girth Weld • Drain + Press Tap • Gamma plug	X	X	X	X		X		
East Turbine Terminal	Creep & Creep Fatigue	• Flange Weld	X	X	X	X		X	West terminal inspected due to access issues.	
Unit 3 Cold Reheat Piping										
West Boiler Link	Fatigue	• Girth Weld	X	X		X		X		
East Turb Terminal	Fatigue	• Flange Weld	X	X		X		X		NR Low Priority due to lack of movement in piping
Drain & Inst Connection East Leg	Fatigue	• Drain & Inst connections below turbine, east side	X	X		X		X		
Unit 1 Feedwater Piping										
HP Feedwater Piping	FAC	• P1 BFP disch elbow & expander		X					UT wall thickness on grid	**2015**: FAC evident. Repair required due to reduce wall thickness.
HP Feedwater Piping	FAC	• HP Flow Element		X					UT wall thickness on grid	**2015**: FAC evident and FE 554. Re-inspection or repair required due to reduce wall thickness.
HP Feedwater Piping	FAC Thermal Fatigue	• EC inlet elbow		X		X			UT wall thickness on grid PAUT at weld root and counterbore notch	**2015**: FAC evident. Re-inspection or repair required due to reduce wall thickness.
SH Attemper-ator	FAC	• West SH Attemp Valve Station		X					UT wall thickness on grid Scan small bore (<= 2")	**2015**: Year of pipe installation/replacement could not be confirmed.
BFP Recirc Piping	FAC	• BFP 2 recirc FCV and piping		X					UT wall thickness on grid	**2015**: Minor FAC. No further inspection required for planned plant life.

Sub-component	Issue	Locations for Inspection	NDE Method						NDE Comment	Comments Findings
			MT	UT	Replica	PAUT[2]	RT	Visual		
LP Feedwater Piping	FAC	• 2nd elbow before DA		X					UT wall thickness on grid	**2015**: Minor FAC. No further inspection required for planned plant life.
Unit 2 Feedwater Piping										
HP Feedwater Piping	FAC	• P1 Disch Elbow		X					UT wall thickness on grid	**2015**: FAC evident. No further inspection required for planned plant life.
HP Feedwater Piping	FAC	• Htr 4 Disch double elbow		X					UT wall thickness on grid	Evidence of FAC
HP Feedwater Piping	FAC	• Htr 5 Disch Tee		X					UT wall thickness on grid	
HP Feedwater Piping	FAC Thermal Fatigue	• Htr 6 Disch Valve, elbow		X		X			UT wall thickness on grid PAUT at weld root and counterbore notch	**2015**: FAC evident. No further inspection required for planned plant life.
SH Attemper-ator	FAC	East SH Attemp Supply Flow Element + piping and Valve Station		X					UT wall thickness on grid	**2015**: FAC evident. No further inspection required for planned plant life.
LP Feedwater Piping	FAC	• Elbow and T out of #2 heater		X					UT wall thickness on grid	No evidence of FAC
Unit 3 Feedwater Piping										
HP Feedwater Piping	FAC	• P1 BFP Disch piping, thermowells, and elbows		X					UT wall thickness on grid	**2015**: Re-inspected. FAC evident; locations below min thickness repaired.
HP Feedwater Piping	FAC	• P2 BFP 45Deg Branch + reducer		X					UT wall thickness on grid	**2015**: FAC evident; locations below min thickness repaired.
HP Low Flow Piping	FAC	• Tees to low flow and attempt + reducer		X					UT wall thickness on grid	NR Outlet tee and piping inspected with no Damage

Sub-component	Issue	Locations for Inspection	NDE Method						NDE Comment	Comments Findings
			MT	UT	Replica	PAUT[2]	RT	Visual		
HP Low Flow Piping	FAC	• Low flow disch to main run - tee + downstream elbow		X					UT wall thickness on grid	Evidence of FAC but not a concern within current target life
HP Feedwater Piping	FAC Thermal Fatigue	• Elbow before EC		X		X			UT wall thickness on grid PAUT at weld root and counterbore notch	Evidence of FAC but not a concern within current target life
LP Feedwater Piping	FAC	• LP Feedwater flow element above Htr 2		X					UT wall thickness on grid	**2015**: Minor FAC. No further inspection required for planned plant life.
SH Attemper-ator Feedwater Station	FAC	East SH Attemp Supply Flow Element + piping and Valve Station		X					UT wall thickness on grid	Possible wall thinning upstream of block valve, at first inlet bend. Pipe was part of replacement in 2010; findings may be due to initial wall variations and not FAC.
HP Feedwater Piping	FAC	• No. 6 Heater discharge bends, full flow Tee and bypass line. • Htr 5 Inlet bends		X						**2015**: Htr 6 bypass inspected. Significant FAC evident. Locations on bend below min wall required replacement. Htr 5 Inlet bends show FAC. No further inspection required for planned plat life.
Unit 3 Generator										
Rotor	General aging and wear	• General visual inspection of major components						X	Resistance measurements and other specialized tests also performed	NR. Previous inspection and test reports, and performance data used to assess condition

Sub-component	Issue	Locations for Inspection	NDE Method						NDE Comment	Comments Findings
			MT	UT	Replica	PAUT[2]	RT	Visual		
Stator	General aging and wear	• General visual inspection of major components						X	Resistance measurements and other specialized tests also performed	NR. Previous inspection and test reports, and performance data used to assess condition
Unit 1 Generator										
Rotor	General aging and wear	• General visual inspection of major components						X	Resistance measurements and other specialized tests also performed	NR. Previous inspection and test reports, and performance data used to assess condition
Stator	General aging and wear	• General visual inspection of major components						X	Resistance measurements and other specialized tests also performed	NR. Previous inspection and test reports, and performance data used to assess condition

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

AN ORDER OF THE BOARD

NO. P.U. __(2016)

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 (Hydro) pursuant to Subsection 41(3) of the *Act*, for approval to replace the lower reheater boiler tubes on Units 1 and 2, and additional reliability improvements at the Holyrood Thermal Generating Station.

WHEREAS the Applicant 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; and

WHEREAS Section 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 in Order No. P.U. 33(2015) the Board approved Hydro's 2016 Capital Budget in the amount of $183,082,800; and

WHEREAS on March 29, 2016 Hydro applied to the Board for approval to replace the lower reheater tubes that service the Unit 1 and 2 boilers at the Holyrood Thermal Generating Station and to complete additional reliability improvements to replace critical equipment and conduct level 2 condition assessments at the Holyrood Thermal Generating Station; and

WHEREAS the capital cost of the project is anticipated to be $11, 800,000; and

WHEREAS the Board is satisfied that the replacement of the lower reheater tubes that service the Unit 1 and 2 boilers at the Holyrood Thermal Generating Station and the additional reliability improvements to replace critical equipment and conduct level 2 condition assessments at the Holyrood Thermal Generating Station are necessary and reasonable to allow Hydro to provide service and facilities which are reasonably safe and adequate and just and reasonable.

IT IS THEREFORE ORDERED THAT:

1. The proposed capital expenditure to replace the lower reheater tubes that service the Unit 1 and 2 boilers at the Holyrood Thermal Generating Station and to complete additional reliability improvements to replace critical equipment and conduct level 2 condition assessments at the Holyrood Thermal Generating Station at an estimated capital cost of $11,800,000 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 , 2016.

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