Q. Please provide a copy of equipment-related root cause or causal analyses reports conducted over 2016-2018.

A. a. Newfoundland and Labrador Hydro Hydraulic Generation:

- Please refer to PUB-NLH-006, Attachment 1: Unit 4 Exciter Arc Net Communications Failure, Bay d’Espoir – January 2016;

- Please refer to PUB-NLH-006, Attachment 2: Unit 5 Exciter Arc Net Communications Failure Bay d’Espoir, January 2016);

- Please refer to PUB-NLH-006, Attachment 3: “Crack Investigation and Repair Report Penstock No. 1 Bay d’Espoir Hydroelectric Development,” Kleinschmidt, June 2016;

- Please refer to PUB-NLH-006, Attachment 4: “Root Cause Analysis Report for Bay d’Espoir Penstock No. 1 Refurbishment,” Hatch, March 17, 2017;

- Please refer to PUB-NLH-006, Attachment 5: Upper Salmon – Rotor Rim Keys, March 2017;

- Please refer to PUB-NLH-006, Attachment 6: Bearing Cooler Leak, Hinds Lake, April 2017;

- Please refer to PUB-NLH-006, Attachment 7: “Surge & Trouble Report 6992, Bay d’Espoir Unit 7 Trip – 2017/07/03,” December 8, 2017;

- Please refer to PUB-NLH-006, Attachment 8: “Repair and Failure Investigation,” Hatch, March 29, 2018;

- Please refer to PUB-NLH-006, Attachment 9: Generator Number 6 Trip, Bay d'Espoir, June 2018;

b. Exploits Hydraulic Generation:

- Please refer to PUB-NLH-006, Attachment 10: GF9 Governor Processor Fault, March 2017;
- Please refer to PUB-NLH-006, Attachment 11: GF 4 Unit Trip due to Deluge System Activation, March 2017;
- Please refer to PUB-NLH-006, Attachment 12: GF9 Friction in Operating Ring Assembly, June 2017;
- Please refer to PUB-NLH-006, Attachment 13: BF 2 Frequency Transducer Alarm, November 2017;
- Please refer to PUB-NLH-006, Attachment 14: "Bishop's Falls Unit 2 Seagull Turbine Field Engineering Survey," American Hydro, August 31, 2018;
- Please refer to PUB-NLH-006, Attachment 15: BF 5 Shaft Seal Cooling Water Flow, January 2018;
- Please refer to PUB-NLH-006, Attachment 16: BF 4 Exciter Board, November 2018;

c. Holyrood Thermal Generation:

- Please refer to PUB-NLH-006, Attachment 17: "Unit 2 Fire Damage and Rehabilitation Holyrood Thermal Generating Station," June 2017;

- Unit 3 fuel oil leak discharge strainers – August 2017.[1]

- Please refer to PUB-NLH-006, Attachment 18: “Unit 2 Boiler Opacity Excursion A TapRoot Investigation, Findings, Report, and Recommendations on the October 28, 2017 Incident,” March 7, 2018;

- Please refer to PUB-NLH-006, Attachment 19: “Fire on Unit 1 Turbine Bearing #2,” February 2018;

- Please refer to PUB-NLH-006, Attachment 20: “Unit-1 FD Fan East Inboard Bearing Failure Report,” June 2018;

- Please refer to PUB-NLH-006, Attachment 21 “Unit 1 Fuel Oil Set – Bunker C Fuel Oil Spill,” June 2018;

- Unit 2 fuel oil set spill – September 2018.[2]

[1] Internal investigations completed by Holyrood staff. No formal report available.
[2] Ibid.

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Newfoundland & Labrador Hydro
HYDRO GENERATION
EQUIPMENT INVESTIGATION REPORT

HELP

Standing Instruction No. 62
Forced Outage Reporting & Investigation

Location: Bay d'Espoir **Unit No:** 4 **Business Unit:** 1293 **Outage No.:** 2016-01

Equipment Name: Bde Unit # 4 Exciter

Brief Description of Event:

Unit 4 Exciter Arc Net Failure

Investigation Assigned to: Lou Willcott

Date of Event: 2016/01/19 **Date of Investigation:** 2016/01/21

Parent Work Order Number: 1166496 **Status of Investigation:** In Progress

Lou Willcott	
Signature of Investigator	**Signature of Approver**

Detailed Description of Event:

See attachment.
With unit at normal shutdown Operations Dept. observed Exciter alrm Arc Net Failure.
C.R. alarm annuciated and operator on shift investigated unit annunciator.
Excitation failure alarm luminated on unit annunciator and Arc net failure alarm displayed on exciter display.

BASIC / ROOT CAUSES:

1. Basic/Root Cause Category: JF - EXCESSIVE WEAR AND TEAR

Basic or Root Cause: Improper extension of service life

Explanation:

Exciter is 20+ years old and starting to experience frequent failures.

2. Basic/Root Cause Category: JF - INADEQUATE MAINTENANCE

Basic or Root Cause: Inadequate preventive maintenance

Explanation:

Investigate if PM's are being completed on a regular basis (ie: yearly - PM6). If not, implement a PM schedule for program monitoring and testing

3. Basic/Root Cause Category:

Basic or Root Cause:

Explanation:

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Newfoundland & Labrador Hydro
HYDRO GENERATION
EQUIPMENT INVESTIGATION REPORT

HELP
Standing Instruction No. 62
Forced Outage Reporting & Investigation

Location:	Bay d'Espoir	Unit No:	4	Business Unit:	1293	Outage No.:	2016-01

Equipment Name: Bde Unit # 4 Exciter

Brief Description of Event:

Unit 4 Exciter Arc Net Failure

BASIC / ROOT CAUSES Cont'd:

4. Basic/Root Cause Category:

Basic or Root Cause:

Explanation:

5. Basic/Root Cause Category:

Basic or Root Cause:

Explanation:

6. Basic/Root Cause Category:

Basic or Root Cause:

Explanation:

7. Basic/Root Cause Category:

Basic or Root Cause:

Explanation:

8. Basic/Root Cause Category:

Basic or Root Cause:

Explanation:

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Newfoundland & Labrador Hydro
HYDRO GENERATION
EQUIPMENT INVESTIGATION REPORT

HELP

Standing Instruction No. 62
Forced Outage Reporting & Investigation

Location:	Bay d'Espoir	Unit No:	4	Business Unit:	1293	Outage No.:	2016-01

Equipment Name: Bde Unit # 4 Exciter

Brief Description of Event:

Unit 4 Exciter Arc Net Failure

BASIC / ROOT CAUSES Cont'd:

9. Basic/Root Cause Category:

Basic or Root Cause:

Explanation:

10. Basic/Root Cause Category:

Basic or Root Cause:

Explanation:

11. Basic/Root Cause Category:

Basic or Root Cause:

Explanation:

12. Basic/Root Cause Category:

Basic or Root Cause:

Explanation:

13. Basic/Root Cause Category:

Basic or Root Cause:

Explanation:

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Newfoundland & Labrador Hydro
HYDRO GENERATION
EQUIPMENT INVESTIGATION REPORT

HELP
Standing Instruction No. 62
Forced Outage Reporting & Investigation

Location: Bay d'Espoir | Unit No: 4 | Business Unit: 1293 | Outage No.: 2016-01

Equipment Name: Bde Unit # 4 Exciter

Brief Description of Event:

Unit 4 Exciter Arc Net Failure

BASIC / ROOT CAUSES Cont'd:

14. Basic/Root Cause Category:

Basic or Root Cause:

Explanation:

15. Basic/Root Cause Category:

Basic or Root Cause:

Explanation:

REMEDIAL ACTIONS:

	Action	Work Order	Responsible	Target Completion	Comp ?
1.	Determine reasonable life expectancy and	1168727	Leyon Williams	2016/03/31	Yes
2.	Investigate if PM's are being completed and/or	1169110	Leyon Williams	2016/03/31	Yes
3.	Increase safety stock (MRQ) Minimum Required	1169117	Alvin Crant	2016/02/29	Yes
4.	Arrange for transfer of spare module from	1169510	Alvin Crant	2016/01/31	Yes
5.	P&C Dept to ensure sufficient spare available	1169641	Karl Inkpen	2016/03/31	Yes
6.	Communicate to Operations Dept to check	1169646	Lou Willcott	2016/02/29	Yes
7.	P&C Dept to check annunciator circuit bringing	1169645	Norbert Benoit	2016/02/29	Yes
8.					
9.					
10.					
11.					
12.					
13.					
14.					
15.					
16.					
17.					
18.					
19.					

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Newfoundland & Labrador Hydro
HYDRO GENERATION
EQUIPMENT INVESTIGATION REPORT

HELP

Standing Instruction No. 62
Forced Outage Reporting & Investigation

Location:	Bay d'Espoir	**Unit No:**	5	**Business Unit:**	1293	**Outage No.:**	2016-02

Equipment Name: Bde Unit # 5 Exciter

Brief Description of Event:

Unit 5 Exciter Arc Net Failure

Investigation Assigned to: Lou Willcott

Date of Event: 2016/01/19 **Date of Investigation:** 2016/01/21

Parent Work Order Number: 1166501 **Status of Investigation:** In Progress

Lou Willcott	
Signature of Investigator	**Signature of Approver**

Detailed Description of Event:

See attachment.

Lead Operator while investigating Unit #4 exciter trouble notice Unit #5 also showed Arc net failure alarm on the exciter display. No exciter alarm was annunciated on the unit annunicator panel.

BASIC / ROOT CAUSES:

1. Basic/Root Cause Category: JF - EXCESSIVE WEAR AND TEAR

Basic or Root Cause: Improper extension of service life

Explanation:

Determine reasonable life expectancy and functionality of control modules (cards).

2. Basic/Root Cause Category: JF - INADEQUATE MAINTENANCE

Basic or Root Cause: Inadequate preventive maintenance

Explanation:

Investigate if PM's are being completed on a regular basis (ie. yearly - PM6). If not, implement a PM schedule for program monitoring and testing.

3. Basic/Root Cause Category: JF - INADEQUATE PURCHASING

Basic or Root Cause: Inadequate receiving inspection and acceptance

Explanation:

Increase safety stock (MRQ) Minimum Required Quantity at BDE to minimize down time going forward.

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Newfoundland & Labrador Hydro
HYDRO GENERATION
EQUIPMENT INVESTIGATION REPORT

HELP

Standing Instruction No. 62
Forced Outage Reporting & Investigation

Location: Bay d'Espoir **Unit No:** 5 **Business Unit:** 1293 **Outage No.:** 2016-02

Equipment Name: Bde Unit # 5 Exciter

Brief Description of Event:

Unit 5 Exciter Arc Net Failure

BASIC / ROOT CAUSES Cont'd:

4. Basic/Root Cause Category: JF - INADEQUATE PURCHASING

Basic or Root Cause: Inadequate mode or route of shipment

Explanation:

Arrange for transfer of spare module from Holyrood to Bay d'Espoir for back-up storage on site to minimize down time going forward.

5. Basic/Root Cause Category:

Basic or Root Cause:

Explanation:

6. Basic/Root Cause Category:

Basic or Root Cause:

Explanation:

7. Basic/Root Cause Category:

Basic or Root Cause:

Explanation:

8. Basic/Root Cause Category:

Basic or Root Cause:

Explanation:

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Newfoundland & Labrador Hydro
HYDRO GENERATION
EQUIPMENT INVESTIGATION REPORT

HELP

Standing Instruction No. 62
Forced Outage Reporting & Investigation

Location:	Bay d'Espoir	Unit No:	5	Business Unit:	1293	Outage No.:	2016-02

Equipment Name: Bde Unit # 5 Exciter

Brief Description of Event:

Unit 5 Exciter Arc Net Failure

BASIC / ROOT CAUSES Cont'd:

9. Basic/Root Cause Category:

Basic or Root Cause:

Explanation:

10. Basic/Root Cause Category:

Basic or Root Cause:

Explanation:

11. Basic/Root Cause Category:

Basic or Root Cause:

Explanation:

12. Basic/Root Cause Category:

Basic or Root Cause:

Explanation:

13. Basic/Root Cause Category:

Basic or Root Cause:

Explanation:

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Newfoundland & Labrador Hydro
HYDRO GENERATION
EQUIPMENT INVESTIGATION REPORT

HELP

Standing Instruction No. 62
Forced Outage Reporting & Investigation

Location: Bay d'Espoir | Unit No: 5 | Business Unit: 1293 | Outage No.: 2016-02

Equipment Name: Bde Unit # 5 Exciter

Brief Description of Event:

Unit 5 Exciter Arc Net Failure

BASIC / ROOT CAUSES Cont'd:

14. Basic/Root Cause Category:

Basic or Root Cause:

Explanation:

15. Basic/Root Cause Category:

Basic or Root Cause:

Explanation:

REMEDIAL ACTIONS:

	Action	Work Order	Responsible	Target Completion	Comp ?
1.	REFER TO 2016-1 for remedial actions.				
2.					
3.					
4.					
5.					
6.					
7.					
8.					
9.					
10.					
11.					
12.					
13.					
14.					
15.					
16.					
17.					
18.					
19.					

CRACK INVESTIGATION AND REPAIR REPORT

PENSTOCK NO.1
BAY D'ESPOIR HYDROELECTRIC DEVELOPMENT

Prepared for:

Newfoundland and Labrador Hydro
St. John's, Newfoundland and Labrador

Prepared by:
Kleinschmidt
Ontario, Canada
www.KleinschmidtGroup.com

June 2016

CRACK INVESTIGATION AND REPAIR REPORT

PENSTOCK NO.1
BAY D'ESPOIR HYDROELECTRIC DEVELOPMENT

Prepared for:

Newfoundland and Labrador Hydro
St. John's, Newfoundland and Labrador

Prepared by:

Kleinschmidt
Ontario, Canada
www.KleinschmidtGroup.com

June 2016

CRACK INVESTIGATION AND REPAIR REPORT

PENSTOCK NO.1 AT BAY D'ESPOIR HYDROELECTRIC DEVELOPMENT

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CRACK INVESTIGATION AND REPAIR REPORT

PENSTOCK NO.1 AT BAY D'ESPOIR HYDROELECTRIC DEVELOPMENT

1.0 BACKGROUND

This report is intended to summarize the site inspection and repair recommendations of a crack that developed in Penstock No.1 at the Bat d'Espoir hydroelectric development owned and operated by Newfoundland and Labrador Hydro (NL Hydro).

On May 21, 2016 water was observed flowing down the hill next to Penstock No.1. NL Hydro investigated and found a two foot long crack on the left side of the 17 foot diameter penstock about 260 meters downstream of the intake. It was estimated that the flow from the crack was about 50L/second and was eroding the soil next to the penstock. Following the discovery the intake was closed and the penstock dewatered to prevent further crack development, stop the leak, and facilitate further investigation inside and outside of the pipe.

Kleinschmidt was retained on May 27, traveled to the area on May 28, and completed a site investigation on the May 29. Notes from that site visit are presented in Section 2 of this report with photos in Appendix B.

2.0 SITE INSPECTION

On May 29, 2016, Christopher M. Vella, P.E., S.E., P.Eng, arrived on site to visually inspect the penstock and crack. Photographs taken during the inspection are in Appendix B of this report. Mr. Vella made the following observations:

- The crack was located at Station 0+260 as measured from the intake (Photo 1) and was measured to be 24.5 inches long from what could be seen visually (Photo 3). Per Drawing F-106-C-7, this location approximately corresponds to Bend No. 3A.
- The crack was observed to be in the base material (penstock plating) and not through the weld material (Photo 2). This cracked area is in what is considered the heat effected zone where the welding process heats the base material enough to alter the properties without melting it. This zone tends to be more brittle than the original base material.
- Rust/corrosion was noted in the crack and was too mature to have developed since the leakage was first observed on May 21 (Photo 5). This indicates that a portion of the crack was initiated prior to the May 21 incident. The rust was light enough that it is likely less than 5 years old but certainly more than a few months.
- Tacten personnel in the pipe recorded video of the crack and the crack appears longer in the video than it does outside of the pipe. The crack could not be reached inside the pipe to measure and verify the length. It was recommended that non-destructive testing (NDT) be performed to verify crack length. (*This was done and results are in Appendix D*).
- Inside measurements were taken to determine if the pipe is out-of-round. Measurements were taken ten feet upstream of the crack and ten feet downstream of the crack. Vertical measurements were taken from the 6 to 12 o'clock positions, and measurements from the 2 to 8 o'clock positions and from the 4 to 10 o'clock positions were taken. Horizontal (3 to 6 o'clock) measurements could not be obtained due to the height of this area and reach limitations.
    - Measurements 10' upstream:
        - 16'-9" (vertical)
        - 17'-2" (4 to 10 o'clock)
        - 16'-11" (8 to 2 o'clock)
    - Measurements 10' downstream:
        - 16'-10" (vertical)
        - 17'-2" (4 to 10 o'clock)
        - 16'-11" (8 to 2 o'clock)

- The out-of-round measurements show the pipe is "squished" by as much as 3" vertically which is less than 2% of the diameter. This is amount is not a concern, would not have caused the crack, and is common for buried large diameter penstocks with high diameter to thickness ratios. Proper compaction and material of the bedding from the invert to the spring line is critical to help support and maintain shape so degradation over time of the bedding material can result in some ovalization of the pipe.

- Ultrasonic thickness readings were taken of the plate around the crack. The average of the readings is 0.422 inches which compares to 0.4375 inches as specified on the drawings. The difference (0.015" or 1/64 th) is minor and within the manufactured tolerance of the plate. This would not have been a direct cause of the failure.

- A section of the backfill/side material on the left side (from point of view looking downstream) of the penstock was slumped several feet vertically for about 40 meters upstream and 40 meters downstream of the crack location (Photos 1 and 8). The most likely cause is saturation of the material which has a high fines content and is susceptible to slope instability due to saturation. Because a penstock leak can cause saturation of the material and lead to slope failure of this kind it is reasonable to assume that a penstock leak may have caused this slope failure and the corrosion in the crack indicates the crack initiated many months before being observed. Because the saturation would not normally go upstream very far, it was recommended that the material upstream of the crack and above the bedding material be pulled out of the way to allow for visual inspection of the penstock upstream of the crack to insure there are no other cracks that may have cause saturation of the fill material in this area.

- The exterior of the penstock was walked along its length to look for possible other areas of settlement, slumps and wet spots. Nothing was found to be concerning or that might indicate other leakage areas.

- The first drain well downstream of the crack location had less than 1 gal/min of flow as visually estimated from looking down from the top. The concrete trough at the bottom was visible and there was no significant build-up of sediment.

- The next drainage well located immediately upstream of the surge tank was half full of water and the bottom could not be seen. It was recommended that this be pumped out and the drainage pipe cleaned to restore flow.

- The site review included discussions about and review of the filling procedure used. The procedure is well thought out with good control, monitoring, and checks in place to ensure the pipe is not overstressed. We found no fault with the filling procedure.

2.1 PROBABLE CAUSE

The failure was likely initiated by a local defect in the material or weld. Because of its location in the heat effected zone at the interface of the weld and base materials it seems like the initial cause might be incomplete fusion. This could be caused by a variety of reasons such as:

1. Incompatibility between the base and weld materials. Unlikely if no other problem areas have been observed at this point in the penstocks life.
2. Improper welding procedure. This id also unlikely if no other problem areas observed.
3. Location specific welder error (e.g. the slag wasn't properly cleaned in this area, or a crater crack). This seems most likely.

Several cycles of dewatering and watering and thermal changes over the years would have caused the crack to initiate at the defect and further loading cycles to increase the size, even if only by a very small amount (<mm). Dewatering the penstock in the spring allows the pipe to warm up and then filling the pipe with cold spring water would result in some of the greatest thermal variance the pipe would see and could cause an existing crack to propagate.

There are no guarantees that there are no other defects or active leaks in the penstock, however, there are no other areas on the penstock that show signs of slumping or to be excessively wet (as may be indicated by vegetation associated with wet areas). There was no significant signs of settlement or misalignment of the penstock and the penstock is not excessively out-of-round. The squish is to the degree that could be expected for a pipe this size so is not a concern.

It is my opinion that once the crack is fixed, and no other cracks are found upstream of the current crack, it is my opinion that the penstock will be safe to fill and operate.

2.2 NEXT STEPS IDENTIFIED FOLLOWING INSPECTION

The following steps were provided to NL Hydro on May 30 and the status of the step as of this report has been noted:

1. Push the penstock plate back into position as best practicable. Using the excavator as an anchor point to push from, place an I-beam (or similar) against the bulge in the penstock, heat the plate area with a torch, and then apply pressure using a jack pushing off the excavator. Insure flush connections between the jack and beam and excavator in order to avoid slipping and sudden load release. This will be difficult because of the pipe slope. Bolt connections when possible between pieces to safeguard against flying parts in the event of a slip is advised for worker safety. (*This step has been completed*)

2. Hydro to work with Tacten to weld in tabs and setup staging inside the penstock in preparation for welding. (*This step has been completed*)

3. Remove exterior coating for at least 6 inches above and below the crack to facilitate testing and welding. Clean area inside penstock for welding. (*This step has been completed*)

4. Once penstock plate is in position the plate/weld should be tested to verify the length of the crack. Shear wave (or angled beam) testing is the preferred method to determine the length of the crack because it is better suited to find deep defects compared to magnetic particle testing. (*This step has been completed and it was found that the crack was 29.5 inches long. NDT results are in Appendix D*)

5. Once the weld testing is complete and the length of crack has been verified by Tacten and confirmed by Kleinschmidt the crack can be cleaned and prepared for welding by grinding out the crack to clean surfaces with an opening large enough to allow for welding access/penetration. (*This step has been completed. Note that preparing the weld surfaces and angles would have been completed after Step 7 below*)

6. Kleinschmidt to complete stress analysis to confirm weld and plate sizing and determine the need for backfill before Friday. Kleinschmidt to advise if backfill required to satisfy allowable stresses and structural integrity of the penstock when full of water. (*This step has been completed. On Thursday June 2 Kleinschmidt advised that the soil backfill was not required for the structural integrity of the penstock in this location*)

7. Kleinschmidt to advise on go for weld and discuss procedure with Tacten welder to complete weld repair of crack. (*Kleinschmidt provided weld procedure and green light for weld on Thursday June 2. A discussion with welder was not had and determined not required for this relatively standard full penetration weld. Kleinschmidt did confirm procedure/intent with Lev Kearley of NL Hydro on Thursday evening. Preparation and*

welding started Thursday night and was completed early Friday. Tests of the new weld are attached in Appendix E)

8. The Devoe Bar Rust 236 is an adequate protective coating for the exterior of the penstock to be applied after welding is complete and the area cleaned. (*Complete*)

9. Pump out drain monitoring well located just upstream of the surge tank and attempt to clear blockage. (*This has been completed*)

10. Monitor flow in drain monitoring wells prior to filling the penstock and then monitor daily following filling for 4 days than weekly for a month. If flow in the wells increase than penstock leakage is likely and volume and turbidity should be assessed. (*Preparation has started for this*)

3.0 ANALYSIS

Stress analysis calculations were performed on the penstock to confirm proper plate sizing for conditions to rule out design error, and to determine need for backfill in area when watered up. The internal pressure or hoop stress was calculated at the crack location for both normal pond and maximum pond (flood) elevations. Buckling of the penstock was also analyzed using external loads on the pipe, mainly soil and snow. The analysis is included in Appendix C.

3.1 INTERNAL PRESSURE

A normal pond elevation of 182.6m (599.08ft) and a flood pond elevation of 184.2m (604.3ft) were used in the hoop stress analysis. The crack location roughly corresponded to Bend No. 3A on Drawing F-106-C-7, which is at approximately El. 508.00ft. Also on the same drawing, the steel type was noted as ASTM A285. A285 Grade C steel was assumed as it is typically used for this large size pipe. A penstock wall thickness of 0.42in was used throughout the analysis based on ultrasonic thickness measurements taken during the field inspection.

The allowable stress intensity is based on the steel yield and ultimate strength values and was calculated as 20 ksi (138 MPa). Both the hoop stress due to normal pond loading and due to flood loading, 14.75 ksi and 15.60 ksi respectively, were less than the allowable stress intensity.

3.2 EXTERNAL PRESSURE

The penstock was analyzed for buckling due to external loads applied to the top 120 degrees of the pipe. The analysis was very conservative as it included the dead weight of the whole shell and the dead load of the water inside. The snow load calculated was approximately 130 psf (6224 Pa). The depth of soil cover on the penstock used was 2ft (0.6m). Another conservative value applied to the top of the penstock was a live load of 100 plf. No vehicular loading was used in the analysis. Also, because the penstock is buried, wind and earthquake were not used in the analysis.

Typical load combinations were calculated and the one producing the maximum load was used. The maximum pressure calculated due to shell dead load, water dead load, soil cover, live load, and snow load was 9.68 psi (66.7kPa). The allowable buckling pressure was calculated as 13.4 psi (92.4kPa).

3.3 CONCLUSION

The stress analysis calculations showed the penstock is adequate as is with calculated stresses well below allowable. Also, because the crack has not opened to a large gap, the suggested weld repair would be a complete joint penetration groove weld as it develops the strength of base material and would satisfy the stress requirements. Leaving the top of the penstock unburied for 30ft +/- will have no ill effect on the penstock's performance.

4.0 RECOMMENDATION AND PROCEDURE

Based on site observations and the analysis discussed on Section 3 above we recommended a complete joint penetration groove weld as the preferred repair as it develops the strength of base material and would satisfy the stress requirements. A plate that would lap over the area and be welded on was also considered and ruled out as unnecessary and potentially requiring more effort to shape the plate to get flush contact around the edges. It would also leave the crack open and able to corrode as getting a good coating in the crack would be very difficult. The proper way would be to remove the crack and close the opening with weld as is being recommended.

4.1 RECOMMENDED REPAIR

Based upon the available information the crack appears to be location specific and is not indicative of a general incompatibility of the existing penstock's weld and base material. Therefore, we recommend weld repair of this specific crack with the following procedure.

1. Remove all existing cracking:
    a. Remove the existing crack by either grinding or carbon air arc gouging.
    b. Magnetic Particle (MT) test the cleaned area, particularly the crack ends to confirm that there is no residual cracking.
    c. If additional cracking is discovered, remove crack and extend removal at least 200mm (8 inches) into sound metal beyond the crack's end.
    d. Retest entire repair area by MT and repeat steps 1.c and 1.d if necessary.
    e. All Non-Destructive Testing (NDT) shall be performed by personnel currently certified to CAN/CGSB-48.9712-2014 Level II or higher for the specific technique being used.
    f. All NDT testing shall conform to the American Society of Mechanical Engineers (ASME) Pressure Vessel and procedures and acceptance criteria.
    g. All MT testing shall be in accordance with ASTM E709-15 Standard Guide for Magnetic Particle Testing.
2. Welding Procedure:
    a. Per the *Profile of Pipeline "A" CL* on Newfoundland Drawing F-106-C-7, the penstock's base material appears to be ASTM A285 steel in the area of the crack (around Bend Number 3A). The material composition of this pressure vessel plate steel (assumed Grade C) is 0.28% Carbon (C), 0.20-0.35% Copper (Cu) by heat

analysis, 0.18-0.37% Copper (Cu) by product analysis, 0.9% Manganese (Mn) by heat analysis, 0.98% Manganese (Mn) by product analysis, 0.035% Phosphorus (P), and 0.035% Sulphur (S).

   b. The penstock's shell shall be welded with a full penetration groove weld in accordance with a welding procedure that complies with either the ASME Section IX Welding and Brazing Qualification, or CSA Standard W59-13 Welded steel construction (metal arc welding).

   c. It is anticipated that most of the welding shall be performed downhand from the exterior of the penstock shell. The procedure shall include backgouging of the back underside of the root pass.

3. Repair Execution:

   a. All welding shall be performed by personnel currently certified to either ASME Section IX or CSA Standard W47.1 Fusion Welding of Steel Company Certification for the approved welding procedure to be used.

   b. After the underside of the root pass is backgouged, the repair weld shall be MT tested before placing the cover pass(es).

   c. After completion of all the welding the repair shall be either MT or Ultrasonic Tested (UT). All UT testing shall comply with the procedures in ASTM E1962-14 Standard Practice for Ultrasonic Surface Testing Using Electromagnetic Acoustic Transducer and acceptance criteria in ASME Section V Nondestructive Examination.

4.2 Follow-Up

It is recommended that the penstock be inspected in two years with specific attention paid to reviewing the deterioration of the internal coating system and to inspecting the repaired area. If the penstock is scheduled to be dewatered on either side of two years than that would be an acceptable time to inspect the penstock to avoid excessive down time if no outages are planned in exactly two years.

Based only on the Hatch penstock report (January 2016) and on site observations it is recommended that the interior of the penstock be recoated within ten to fifteen years. The interior coating system is failing and light surface rust was noted. A typical practical approach to determining a recoating timeline would be to clearly mark a few spots where the existing coating has delaminated and monitor these exact locations to see how quickly corrosion, particularly surface pitting, develops. If you visually inspect and UT measure thicknesses at identical monitoring spots once every year or two for 3 to 5 years you should have a realistic determination of the rate of corrosion. Pitting development is particularly troublesome because it: 1) obviously decreases the base metal's strength, and 2) the pits will have thinner coating thicknesses around the edges that shorten a coating's service life. The interior should be cleaned and coated prior to significant corrosion and pitting development. We have seen the interior of uncoated 100 year old penstocks very smooth (e.g. PacifiCorp Pioneer penstock in 2014), and newer ones heavily pitted. (e.g. Enel Pyrites new unit at only 11 years old in 2006). A big difference we’ve noticed is if the penstock is buried or above ground.

Steel corrosion generally requires oxygen, and as the steel surface rusts it prevents oxygen from penetrating deeper. But if the surface rust is disturbed, such as when an above grade penstock expands and contracts the surface rust delaminates from the substrate allowing oxygen to penetrate deeper and continue substrate corrosion. Buried penstocks are a more stable environment and therefore generally display less corrosion and surface pitting. Also conditions such as the water quality (e.g. low chloride), the type of soil burying the penstock, and galvanic potential between mating materials (e.g. weld filler and base steel) can have a significant effect. Based on past performance of similar penstocks it would take several decades for the corrosion to degrade the penstock shell to the point that the structural integrity would start to become compromised based purely on section loss; however, to maintain safety factors, to avoid localized stresses that pitting could develop, to ensure longevity of a new coating system and a long service life for the penstock, it is advised that the penstock be recoated in less than ten years. At this time it is understood that Penstock No. 2 will be inspected this summer. Because this author has not been in either Penstock No. 1 or Penstock No. 2, it is recommended that the inspector make specific observations and recommendations in their report regarding the coating system of Penstock No. 2 and should mark a few locations for future testing to observe rate of deterioration.

We can provide a coating specification if required.

5.0 PENSTOCK INSPECTIONS

Newfoundland Hydro asked what would be a typical inspection frequency and what would be part of a typical penstock inspection.

5.1 INSPECTION FREQUENCY

There is no set industry standard that recommends all penstocks should be inspected at a set frequency. Our experience has been that a penstocks inspection frequency should be determined on a case by case bases after considering several factors which include:

- Age of penstock
- Type of penstock
- Coating system
- Support system
- Buried or unburied
- Water quality and sediment load
- Frequency of load rejections
- Hazard Class
- Access issues
- Criticality of facility to power production

A penstock should have an exterior inspection by the owner every 1 to 5 years depending on the factors listed above. If at a manned facility a walk of the exterior by operations staff monthly is not unusual and at least annually is common practice for all penstock types. In general, a newer steel penstock (less than 30 years old) would be inspected at least every five years by the owner and have a full internal inspection by a qualified engineer about every ten years, planned around outages, and generally would concentrate on interior and exterior coating, settlement and movement of penstock and supports, shape, and condition of penetrations. Future frequency of inspections would be dependent on the findings of the previous inspections and would be largely dependent on how well the coating system is holding up and if any structural concerns were developing. Specific non-destructive testing of welds would not typically be included unless an observation and recommendation from the inspector required it. An older steel penstock (more than 30 years as this is the life expectancy of some coating systems) with no significant issues but with coating system deterioration should have an internally inspection every five years by a qualified engineer to track the rate of coating deterioration and corrosion development such that a timeline can be developed for recoating or patching. An older steel penstock with known issues (thinning sections, patches, significant corrosion, leaks, settlement, etc.) should be inspected at least annually by the owner and two to five years by a qualified engineer who would be involved in recommending repairs and a timeline based on degree and type of issues. Selective non-destructive testing of welds would be expected to start every five years or when recommended by the inspector.

An old wood stave penstock (there are no new ones) in good condition should have an exterior inspection annually by the owner with five year inspections by a qualified engineer experienced with wood stave penstocks. A wood stave penstock with known issues (significant leaks, patches, rotting wood, significantly corroded banding) should be inspected at least semi-annually by the owner as this type of penstock can develop issues quickly in harsh environments and this will facilitate repairs that can become an annual maintenance item. Inspection by a qualified engineer may be required bi-annually or annually depending on the amount and rate of deterioration.

A new fiberglass penstock would be expected to go 10 to 15 years before its first internal inspection and another ten before its second. Future frequency of inspections would be dependent on the findings of the previous inspections and would be largely dependent on if any structural concerns were developing (ovaling, settlement, leaks, UV related deterioration, hairline cracking).

These are general timelines based on our experience and more specific timelines would require knowledge of the penstocks. With the appropriate information (material, buried or unburied, support type, age, drawings, coating info, and inspection reports) we could perform a simple desk top study to provide preliminary recommendations for inspection frequency for specific penstocks that could be refined as penstocks are inspected and the condition and rate of deterioration is assessed.

Inspections are generally carried out by experienced and qualified engineers that may be staff engineers or consultants. Independent or third party inspections of penstocks is not widely required by regulation in the industry at this time but often done by owners looking for an independent review or without qualified staff. The Federal Energy Regulatory Commission

(FERC) in the United States is currently developing guidelines for penstock inspections but these have not yet been released. The CDA Guidelines do not address penstock inspections in any significant detail.

5.2 Inspection Scope

I have provided here a summary of what a typical steel penstock inspection scope should include but the scope is typically tailored for each site. I have left out means and methods as that would add significant detail and could be a report on its own for all the various aspects.

1. Document review – Review of available documents is important to understand the penstock prior to performing the inspection. Documents that we would normally ask for include:

    a. Design and Construction history review including drawings, design criteria, design calculations, foundation information, and maintenance records.

    b. Operational History review such as steady state conditions, operating records, reservoir rule curves, headwater and tailwater rating curves, transient flow conditions, load acceptance and rejection tests, and wicket gate opening/closing times.

    c. Previous inspection reports

2. Exterior Inspection – A walk down of the exterior of the penstock buried or unburied preferably when the pipe is at operational pressures. For buried penstocks you're looking for slumps or sloughing of sloped material next to penstock, for wet areas, significant depressions, settlement, and holes. A penstock would need to be deep (more than twice its diameter from crown), in a rock tunnel, or overgrown to consider not walking the exterior. For exposed penstocks you should take wall/shell thickness readings with UT gage at representative locations (at least every time the pipe changes thickness, material, or coating). An inspection should check alignment, settlement and condition of supports, sagging of penstock between supports, out-of-roundness, and condition of coating with paint thickness measurements if applicable. Condition of ring girders and saddle supports should be reviewed along with all joints. Welded, riveted, and bolted joints,

seams and connections should be visually inspected. All penetrations should be inspected including vent pipes, stand pipes, piezometers, surge tank entrance, and valves. Thrust blocks should be reviewed for condition and movement/settlement. The surge tank should also be inspected but this may be separated from the penstock as this can be a significant effort on its own.

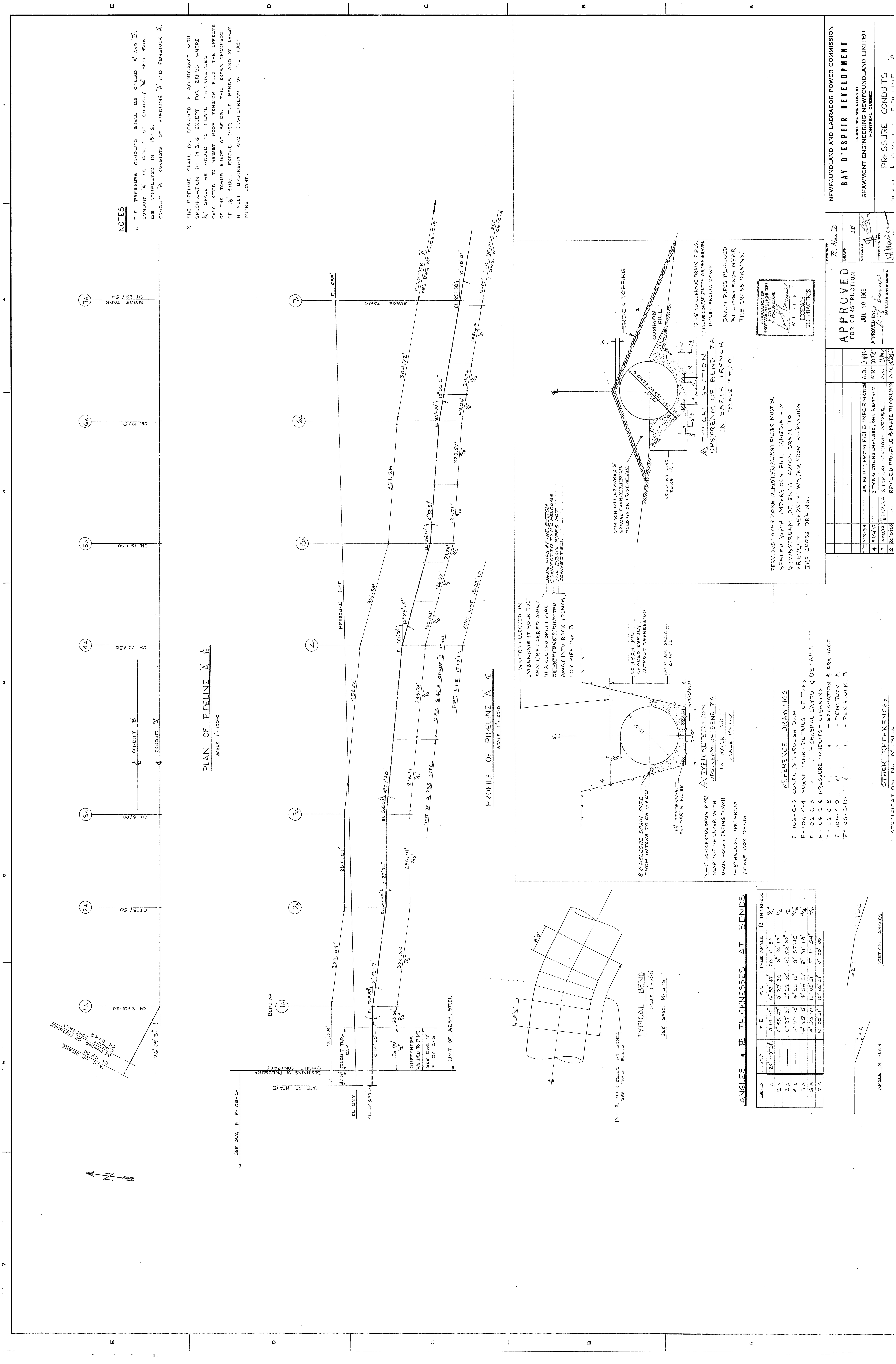
3. Interior Inspection – A dewatered inspection of a penstock is the best way to check for corrosion, erosion, and cavitation, the condition of coating, and a good way to measure out-of-roundness but understand that the degree of out-of-roundness will be more when dewatered than when at operational pressures. The coating and the wall thickness should be measured at representative intervals at the invert, crown and spring line and a few places of corrosion should be marked for future inspections such that rate of deterioration can be assessed. Organic growth should also be commented on (thickness, type, is it affecting the coating). It is expected that all personnel safety requirements will be followed (confined space, safe work plan, Rescue Plan, fall arrest, etc)

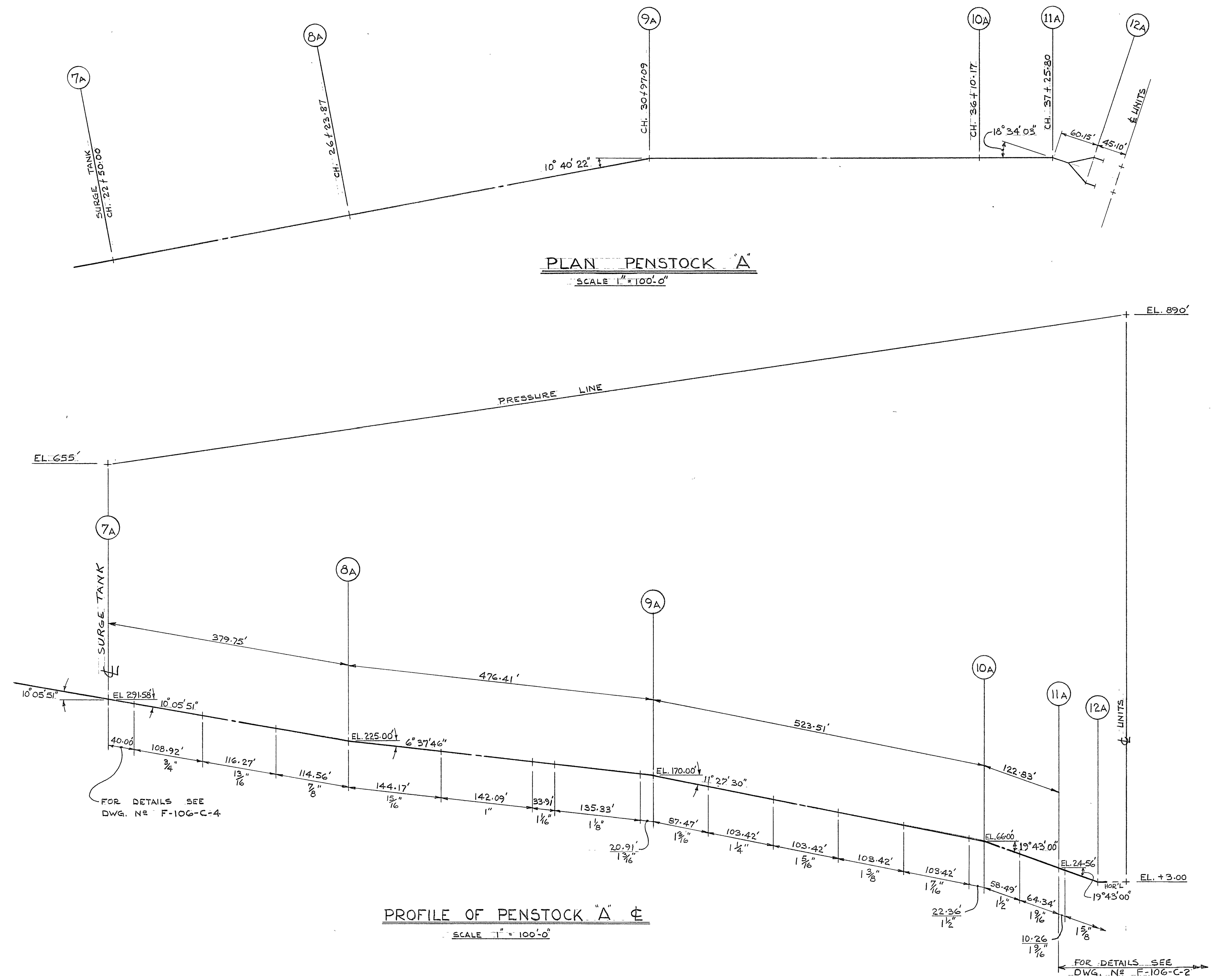
4. Stress analysis – if an analysis is not available then consider analyzing the penstock for current operating conditions, wicket gate closure times, and with current shell thickness.

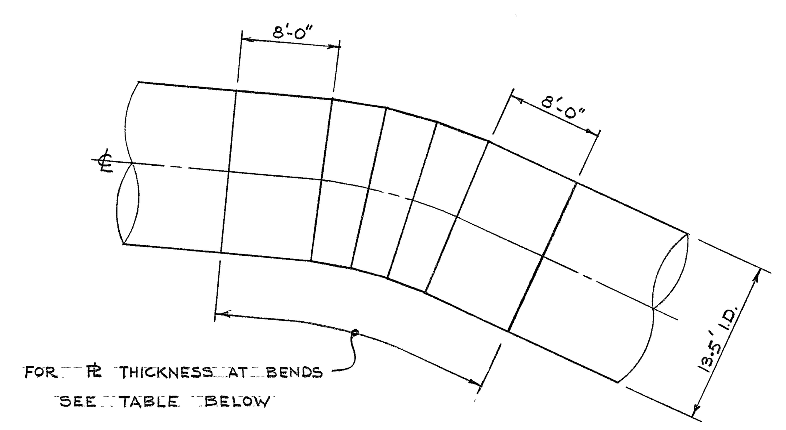
5. Report – a detailed report of all observations based on the above scope with specific recommendations with timelines for mitigation, repairs, coatings, and follow-up inspections if required.

APPENDIX A

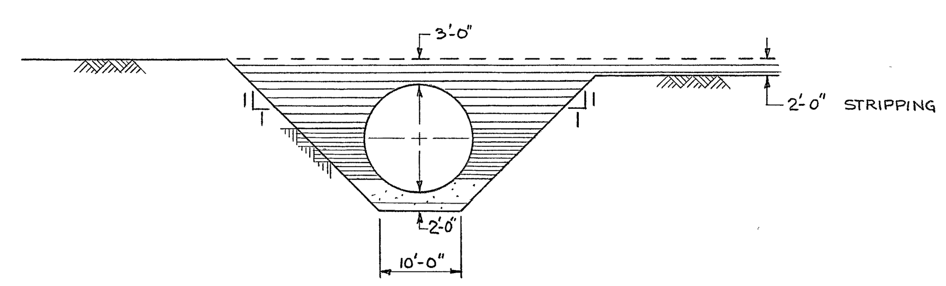
FIGURES


NOTES
1. THE PRESSURE CONDUITS SHALL BE CALLED "A" AND "B". CONDUIT "A" IS SOUTH OF CONDUIT "B" AND SHALL BE COMPLETED IN 1966. CONDUIT "A" CONSISTS OF PIPELINE "A" AND PENSTOCK "A".
2. THE PIPELINE SHALL BE DESIGNED IN ACCORDANCE WITH SPECIFICATION Nº M-3116 EXCEPT FOR BENDS WHERE 1/8" SHALL BE ADDED TO PLATE THICKNESSES CALCULATED TO RESIST HOOP TENSION PLUS THE EFFECTS OF THE TORUS SHAPE OF BENDS. THIS EXTRA THICKNESS OF 1/8" SHALL EXTEND OVER THE BENDS AND AT LEAST 8 FEET UPSTREAM AND DOWNSTREAM OF THE LAST MITRE JOINT.
PLAN OF PIPELINE "A" ℄
SCALE 1" = 100'-0
PROFILE OF PIPELINE "A" ℄
SCALE 1" = 100'-0"
TYPICAL BEND
SCALE 1" = 10'-0
SEE SPEC. M-3116
FOR ℞ THICKNESSES AT BENDS SEE TABLE BELOW
ANGLES & ℞ THICKNESSES AT BENDS
BEND | <A | <B | <C | TRUE ANGLE | ℞ THICKNESS
1A | 26° 09' 31" | 0° 14' 50" | 6° 53' 47" | 26° 55' 34" | 7/16"
2A | — | 6° 53' 47" | 0° 27' 30" | 6° 26' 17" | 1/2"
3A | — | 0° 27' 30" | 5° 27' 30" | 5° 00' 00" | 1/2"
4A | — | 5° 27' 30" | 14° 25' 15" | 8° 57' 45" | 9/16"
5A | — | 14° 25' 15" | 4° 53' 57" | 9° 31' 18" | 3/4"
6A | — | 4° 53' 57" | 10° 05' 51" | 5° 11' 54" | 13/16"
7A | — | 10° 05' 51" | 10° 05' 51" | 0° 00' 00" |
ANGLE IN PLAN
VERTICAL ANGLES
TYPICAL SECTION UPSTREAM OF BEND 7A IN ROCK CUT
SCALE 1" = 1'-0"
TYPICAL SECTION UPSTREAM OF BEND 7A IN EARTH TRENCH
SCALE 1" = 1'-0"
WATER COLLECTED IN EMBANKMENT ROCK TOE SHALL BE CARRIED AWAY IN A CLOSED DRAIN PIPE OR PREFERABLY DIRECTED AWAY INTO ROCK TRENCH FOR PIPELINE B
DRAIN PIPE AT THE BOTTOM CONNECTED TO 8"Ø HELCORE TOP DRAIN PIPES NOT CONNECTED.
8"Ø HELCORE DRAIN PIPE FROM INTAKE TO CH. 5+00
COMMON FILL GRADED EVENLY WITHOUT DEPRESSION
REGULAR SAND ZONE 12
2—6" NO-CORRODE DRAIN PIPES NEAR TOP OF LAYER WITH DRAIN HOLES FACING DOWN
1—8" HELCOR PIPE FROM INTAKE BOX DRAIN
COMMON FILL, CROWNED 6" GRADED EVENLY TO AVOID PONDING ON CREST OF FILL
ROCK TOPPING
COMMON FILL
2—6" NO-CORRODE DRAIN PIPES, INSIDE COARSE FILTER OR PEA GRAVEL HOLES FACING DOWN
DRAIN PIPES PLUGGED AT UPPER ENDS NEAR THE CROSS DRAINS.
PERVIOUS LAYER ZONE 12 MATERIAL AND FILTER MUST BE SEALED WITH IMPERVIOUS FILL IMMEDIATELY DOWNSTREAM OF EACH CROSS DRAIN TO PREVENT SEEPAGE WATER FROM BY-PASSING THE CROSS DRAINS.
REFERENCE DRAWINGS
F-106-C-3 CONDUITS THROUGH DAM
F-106-C-4 SURGE TANK - DETAILS OF TEES
F-106-C-5 " " - GENERAL LAYOUT & DETAILS
F-106-C-6 PRESSURE CONDUITS - CLEARING
F-106-C-8 " " - EXCAVATION & DRAINAGE
F-106-C-9 " " - PENSTOCK A
F-106-C-10 " " - PENSTOCK B
OTHER REFERENCES
1. SPECIFICATION No. M-3116
ASSOCIATION OF PROFESSIONAL ENGINEERS PROVINCE OF NEWFOUNDLAND
LICENCE TO PRACTICE
APPROVED FOR CONSTRUCTION
JUL 16 1965
5 | 2-6-68 | AS BUILT, FROM FIELD INFORMATION | A.B.
4 | 5JAN'67 | 2 TYP. SECTIONS CHANGED, ONE REMOVED | A.R.
3 | 9DEC'66 | 3 TYPICAL SECTIONS ADDED | A.R.
2 | | REVISED PROFILE & PLATE THICKNESSES | A.R.
DESIGNED R. Mac D.
DRAWN J.P.
NEWFOUNDLAND AND LABRADOR POWER COMMISSION
BAY D'ESPOIR DEVELOPMENT
ENGINEERING AND DESIGN BY
SHAWMONT ENGINEERING NEWFOUNDLAND LIMITED
MONTREAL, QUEBEC
PRESSURE CONDUITS
PLAN & PROFILE PIPELINE "A"





TYPICAL BEND
SCALE 1" = 10'-0"



TYPICAL CROSS SECTION (9A) TO (11A)
SCALE 1" = 15'-0"

BEND	< A	< B	< C	TRUE ANGLE	PL THICKNESS
7 A	—	10° 05' 51"	10° 05' 51"	0° 00' 00"	—
8 A	—	10° 05' 51"	6° 37' 46"	3° 28' 05"	1 1/8"
9 A	10° 40' 22"	6° 37' 46"	11° 27' 30"	11° 35' 25"	1 3/8"
10 A	—	11° 27' 30"	19° 43' 00"	8° 15' 30"	1 3/4"
11 A	18° 34' 03"	19° 43' 00"	19° 43' 00"	17° 28' 12"	1 7/8"

ANGLES & PL THICKNESS AT BENDS

ANGLE IN PLAN

VERTICAL ANGLES

NOTES

1. THE PENSTOCK SHALL BE DESIGNED IN ACCORDANCE WITH SPECIFICATION Nº M-3116 EXCEPT FOR BENDS WHERE 1/8" SHALL BE ADDED TO PLATE THICKNESSES CALCULATED TO RESIST HOOP TENSION AND THE EFFECTS OF THE TORUS SHAPE OF BENDS. THIS EXTRA THICKNESS OF 1/8" SHALL EXTEND OVER THE BENDS AND AT LEAST 8 FEET UPSTREAM AND DOWNSTREAM OF THE LAST MITRE JOINT.
2. THE INTERNAL DIAMETER OF THE PENSTOCK IS 13'-6".
3. STEEL SHALL BE C.S.A. G40-8 GRADE 'B'.
4. FOR TYPICAL CROSS SECTION FROM (7A) TO (9A) SEE DWG. Nº F-106-C-7.

REFERENCE DRAWINGS

1. F-106-C-2 PRESSURE CONDUITS - LAYOUT & DETAILS OF BIFURCATION.
2. F-106-C-4 SURGE TANKS - DETAILS OF TEES.
3. F-106-C-5 SURGE TANKS - GENERAL LAYOUT & DETAILS.
4. F-106-C-6 PRESSURE CONDUITS - CLEARING.
5. F-106-C-7 PRESSURE CONDUITS - PLAN & PROFILE PIPE LINE 'A'.

OTHER REFERENCES

1. SPECIFICATION Nº M-3116

ASSOCIATION OF PROFESSIONAL ENGINEERS PROVINCE OF NEWFOUNDLAND
W. E. BONNELL
LICENCE TO PRACTICE

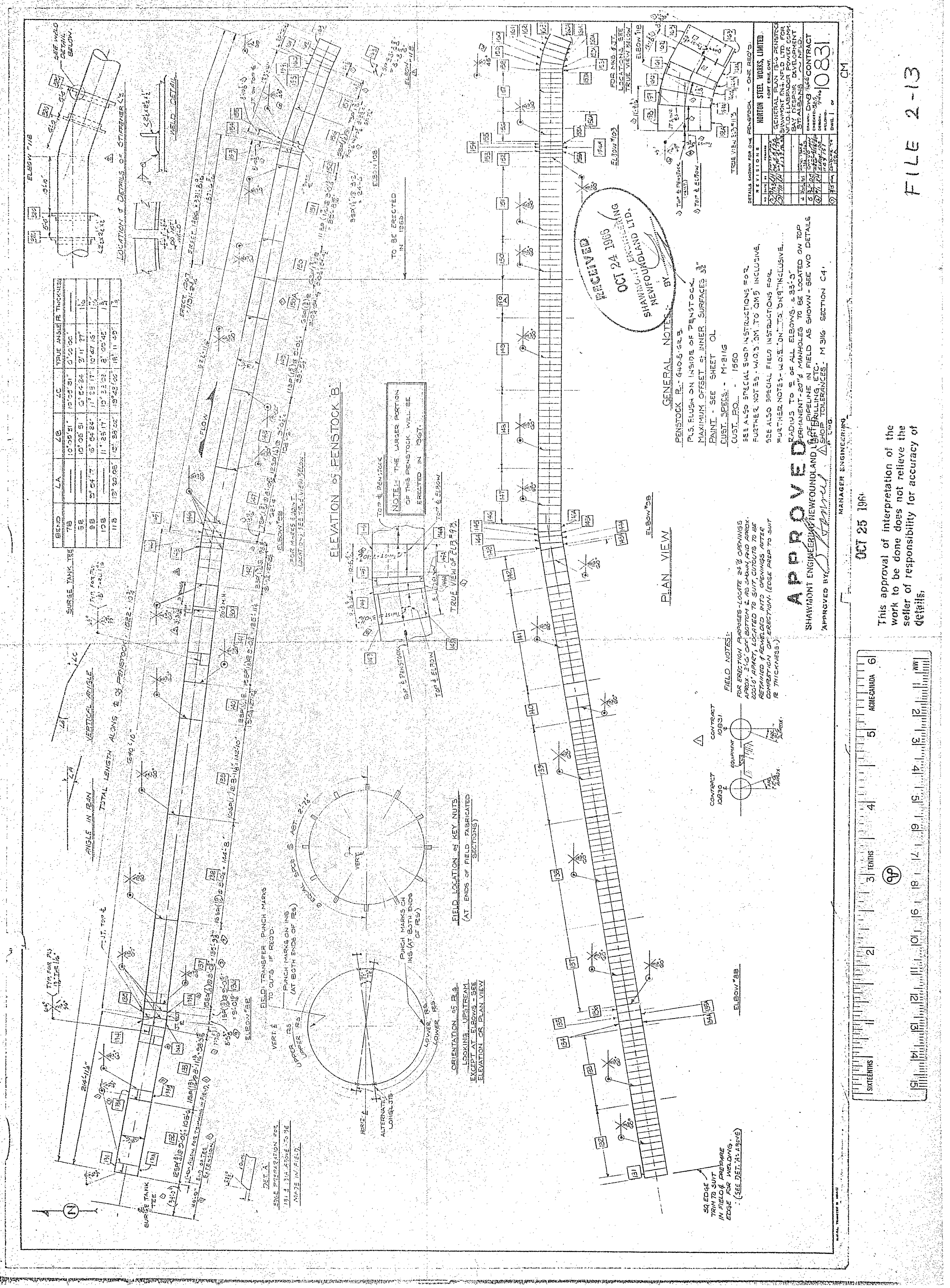
APPROVED FOR CONSTRUCTION
SEP 22 1965
APPROVED BY:
MANAGER ENGINEERING

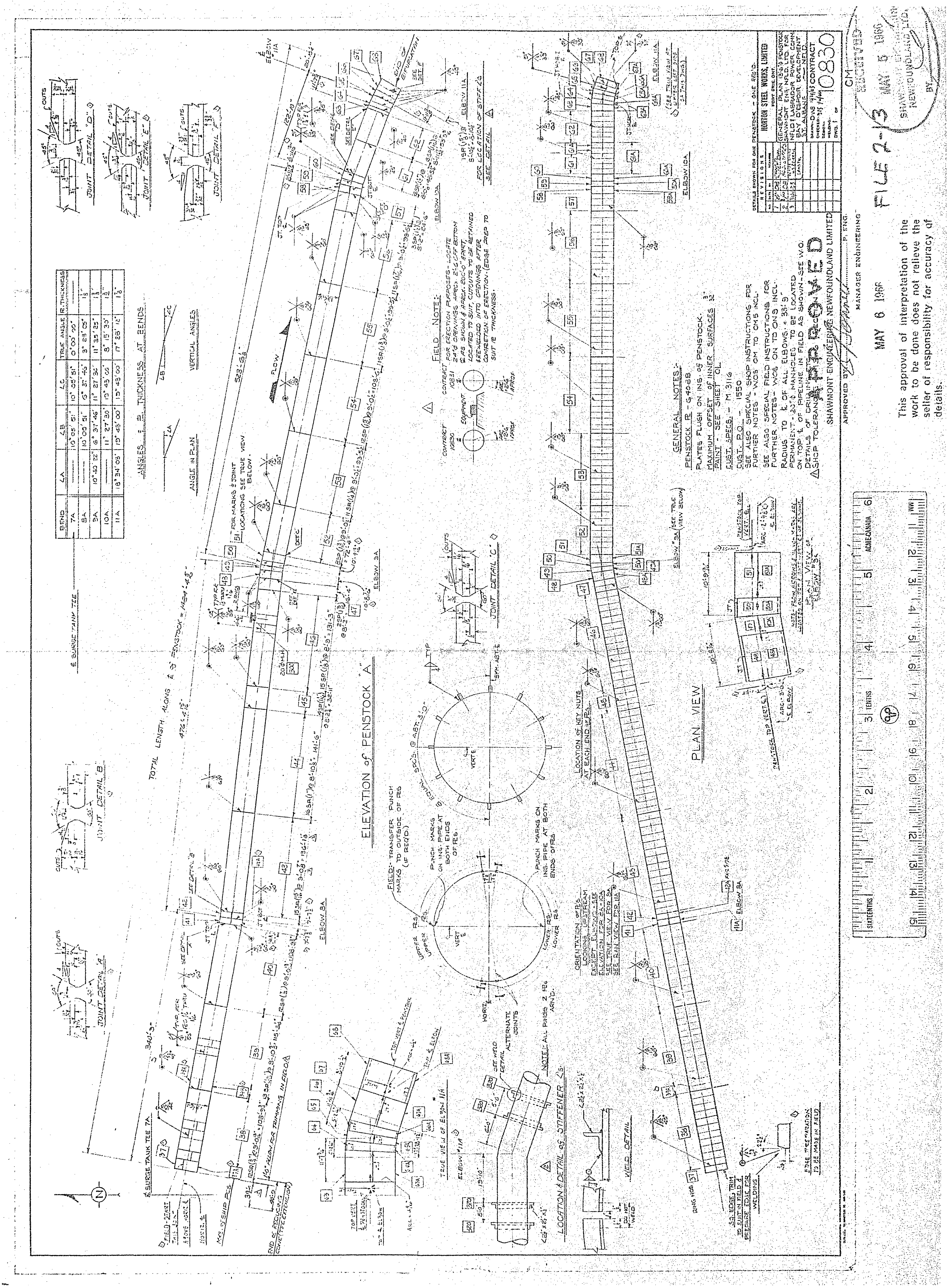
DESIGNED R. MAC D.
DRAWN J.P.
CHECKED A.P. K.
RECOMMENDED

NEWFOUNDLAND AND LABRADOR POWER COMMISSION
BAY D'ESPOIR DEVELOPMENT
ENGINEERING AND DESIGN BY
SHAWMONT ENGINEERING NEWFOUNDLAND LIMITED
MONTREAL, QUEBEC

PRESSURE CONDUITS
PLAN & PROFILE PENSTOCK 'A'

3	SEPT 3/65	PLAN & PROFILE REVISED	J.P.	


ELEVATION of PENSTOCK 'B'
PLAN VIEW
GENERAL NOTES
NOTE: THE LARGER PORTION OF THIS PENSTOCK WILL BE ERECTED IN 1967.
TO BE ERECTED IN 1966.
FLOW
APPROVED
SHAWMONT ENGINEERING NEWFOUNDLAND LTD.
OCT 25 1966
This approval of interpretation of the work to be done does not relieve the seller of responsibility for accuracy of details.
RECEIVED
OCT 24 1966
HORTON STEEL WORKS, LIMITED
10831
FILE 2-13


ELEVATION of PENSTOCK "A"
PLAN VIEW
ANGLES & R THICKNESS AT BENDS
FIELD NOTE:
GENERAL NOTES:
HORTON STEEL WORKS, LIMITED
SHAWMONT NEWFOUNDLAND LIMITED
MANAGER ENGINEERING
MAY 6 1966
FILE 2-13
10830
This approval of interpretation of the work to be done does not relieve the seller of responsibility for accuracy of details.


12 X
APPROVED
SHAWMONT ENGINEERING NEWFOUNDLAND LIMITED
This approval of interpretation of the work to be done does not relieve the seller of responsibility for accuracy of details.
TYPICAL ASSEMBLY
MATERIAL SPECS.
NOZZLE
USAGE OF PENSTOCK CUTOUT
24"Ø MANHOLE DETAILS
ONE REQ'D.
DETAIL "A"
DETAIL "B"
PLAN OF M.H. COVER
ELEV. OF COVER
PUSH-OFF BOLT
HINGE PIN
HORTON STEEL WORKS, LIMITED
68H038H03
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AUG 20
SHAWMONT NEWFOUNDLAND LTD.
FILE COPY
NEWFOUNDLAND AND LABRADOR POWER COMMISSION

APPENDIX B

INSPECTION PHOTOGRAPHS

PHOTO 1 – LOOKING DOWNSTREAM FROM THE INTAKE AREA AT THE DAMAGED AREA OF PENSTOCK NO.1

PHOTO 2 – CRACK IN PENSTOCK PLATE ALONG LONGITUDINAL WELD

PHOTO 3 – MEASURING VISIBLE LENGTH

PHOTO 4 – USING STRAIGHT BAR TO HIGHLIGHT BULGE IN PENSTOCK PLATE

PHOTO 5 – CLOSE-UP OF CRACK. NOTE CORROSION IN CRACK THAT APPEARS OLDER THAN ONE WEEK.

PHOTO 6 – LOOKING UPSTREAM ALONG CRACK LOCATION WITH BACKFILL REMOVED

PHOTO 7 – LOOKING UPSTREAM FOR SIDE VIEW OF CRACK AND BULGE

PHOTO 8 – LOOKING AT THE LEFT SIDE OF THE PENSTOCK IN AREA OF CRACK. NOTE SLUMPED BACKFILL

Appendix C

Penstock Stress Calculations

Kleinschmidt

P.O. Box 650
141 Main St.
Pittsfield, Maine 04967
Telephone: 207.487.3328
www.KleinschmidtUSA.com

Designed By: LLC
Date: 6/1/16
Checked By: CMV
Date: 6/2/16
Job Number: 2670003.00

Project: Bay d'Espoir Penstock

Task: Penstock Calculations - Crack Weld

Objective:

Based on an site visit by CMV regarding a logintudinal crack in the base material following a longitudinal weld:
- *Design crack weld repair*
- *Check buried pipe condition*

References:

1. *ASCE No. 79, 2nd Ed. 2012*
2. *AWWA M11, 4th Ed.*
3. *AISC Design Guide 15 Historic Shapes and Specifications*
4. *Structural Design in Metals, 2nd Ed. 1957*
5. *AISC Steel Construction Manual - 14th Ed.*
6. *AISI - Buried Steel Penstocks - Steel Plate Engineering Data - Vol. 4, 2nd Ed. 1998*
7. *ASCE 7-10*
8. *Bureau of Reclamation, "Welded Steel Penstocks" Engineering Monograph No. 3, 1977*
9. *Hydroelectric Handbook, 2nd ed., 1950*
10. *Obsolete Canadian Steel Grades 1935-1971*
11. *Drawings from client*

Assumptions and Inputs:

$\gamma_w := \mathbf{62.4}\text{pcf}$ — *Unit weight of water*

$\gamma_s := \mathbf{490}\text{pcf}$ — *Unit weight of steel*

$E_{steel} := \mathbf{29000}\text{ksi}$ — *MOE of steel*

$\mu := \mathbf{0.3}$ — *Poisson's ratio of steel*

$$\alpha := \frac{0.00065 \cdot \Delta°F^{-1}}{100} = 6.50 \times 10^{-6} \cdot \Delta°F^{-1}$$ *Coefficient of thermal expansion for steel*

$L_{pen} := 3800\text{ft}$ — *Total length of penstock*

$D_i := 17\text{ft}$ — *Diameter of penstock*

$r_i := \frac{D_i}{\mathbf{2}} = 8.5\,\text{ft}$ — *Radius of penstock*

$NP := 182.6 \cdot m \quad NP = 599.08\,\text{ft}$ — *Normal Pond Elevation*

$CE := 508.0 \cdot ft$ — *Elevation of Penstock crack location (around 3A per client)*

$P_{crack} := (NP - CE) \cdot \gamma_w$ — *Normal Pressure at crack* — $P_{crack} = 39.47\,\text{psi}$

$FP := 184.2 \cdot m \quad FP = 604.33\,\text{ft}$ — *Flood Elevation*

$P_{flood} := (FP - CE) \cdot \gamma_w$ — *Pressure due to flood load at crack* — $P_{flood} = 41.74\,\text{psi}$

Kleinschmidt Associates
Pittsfield, Maine

By: LLC Date: 6/3/2016
Checked by: _____ Date: ______

Pipe Vintage and Joint Type :

The penstock is welded plate steel ASTM A285 changing to G40.8 Grade B after crack location, 1965+/-. Do not know grade of A285 Steel. Assume Grade C.

1965 Welded:

Use Reference 10 and ASTM.

$F_{u\_1965} := 55\cdot ksi$ — *Assumed tensile strength of steel pipe ASTM A285 Gr.C*

$F_{y\_1965} := 30\cdot ksi$ — *Assumed yield strength of steel pipe ASTM A285 Gr.C*

$S_{A\_1965} := \min\left(\frac{F_{u\_1965}}{2.4}, \frac{F_{y\_1965}}{1.5}\right) = 20.0\cdot ksi$ — *Allowable stress intensity (R1, 3.5.3)*

Check Thickness (R1, Eqns 4-1 through 4-4):

$\boxed{t_{wall} := 0.42in}$ — *Penstock thickness*

$\boxed{P_{design} := P_{crack}}$ — *Maximum (design) internal pressure at crack*

$P_{design} = 39.47\ psi$

$E := 0.65$ — *Joint Efficiency (welded) - (R1, Table 3-3, "Single Welded butt joints with backing bars")*

$t_{min\_\sigma} := \frac{P_{design}\cdot r_i}{E\cdot S_{A\_1965}} = 0.31\cdot in$ — *Minimum required thickness based on max internal pressure (R1, Eqn 4-1)*

$check_{min\_t} := if\left(t_{wall} \geq \max\left(t_{min\_\sigma}\right), \text{"OK"}, \text{"No Good"}\right)$ — $check_{min\_t} = \text{"OK"}$

Check Internal Pressure:

$\sigma_p := \frac{P_{design}\cdot r_i}{E\cdot t_{wall}} = 14.75\cdot ksi$ — *Stress applied*

$S_{A\_1965} = 20.00\cdot ksi$ — *Allowable stress*

$check_{Stress} := if\left(S_{A\_1965} \geq \sigma_p, \text{"OK"}, \text{"No Good"}\right)$ — $check_{Stress} = \text{"OK"}$

$\sigma_f := \frac{P_{flood}\cdot r_i}{E\cdot t_{wall}} = 15.60\cdot ksi$ — *Stress due to flood*

$check_{StressF} := if\left(S_{A\_1965} \geq \sigma_f, \text{"OK"}, \text{"No Good"}\right)$ — $check_{StressF} = \text{"OK"}$

Allowable Transient Pressure:

$R_p := \frac{D_i + t_{wall}}{2} = 102.21\cdot in$ — *Radius of the middle surface of the pipe shell*

$P_t := \frac{S_{A\_1965}\cdot E\cdot t_{wall}}{R_p} = 53.42\ psi$ — *Max transient pressure allowed*

Weld suggestions for crack:

Prequalified Welded Joints, Complete-Joint-Penetration Groove Welds, Table 8-2, R5

1. Single-V-groove weld with backer bar.
2 Single-bevel-groove weld with backer bar.

Check Buckling - Buried Pipe Condition:

ASD Load Combinations & Factors (R7, 2.4.1):

Dead = D, Live = L, Roof live = Lr, Snow = S, Rain = R, Wind = W, Earthquake = EQ

Load Combinations:

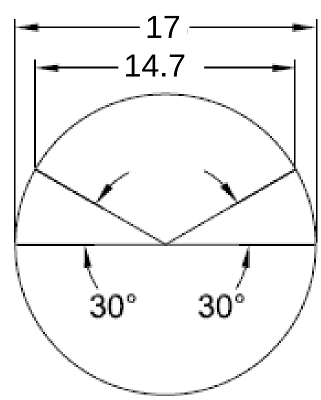
LC1 = D
LC2 = D + L
LC3 = D + (Lr or S or R)
LC4 = D + 0.75L + 0.75(Lr or S or R)
LC5 = D ± (0.6W or 0.7EQ)
LC6 = D + 0.75(0.6W or 0.7EQ) + 0.75L + 0.75(Lr or S or R)
LC7 = 0.6D ± (0.6W or 0.7EQ)

Live Load:

$LL := \mathbf{100}\,plf$ — *Assumed live load of workers walking on the penstock*

Wind Load & Earthquake Load:
Will not control, buried. Not applicable.

Snow and/or Ice Load (R7, Chapter 7):



$p_g := \mathbf{120}\,psf$ — *Ground snow load (assume 120psf)*

$I := \mathbf{1.0}$ — *Importance factor (R7, Table 1.5-2, Risk Cat. II)*

$C_t := \mathbf{1.2}$ — *Thermal factor (R7, Table 7-3, Unheated, Open Air)*

$C_e := \mathbf{0.9}$ — *Exposure factor (R7, Table 7-2, Fully Exposed, Terrain Cat. B)*

$C_s := \mathbf{1.0}$ — *Roof slope factor conservatively assumed for area above 30 deg as shown (R7, Fig. 7-2)*

$p_s := C_s \cdot C_e \cdot C_t \cdot I \cdot p_g = 129.6 \cdot psf$ — *Design snow pressure*

$\boxed{w_{snow} := p_s \cdot (14.72ft) = 1907.7 \cdot plf}$ — *Design snow load*

Properties:

$\boxed{t_{wall} = 0.420 \cdot in}$ — *Penstock wall thickness*

$D_i = 17.00\ ft$ — *Inner diameter of penstock*

$D_o := D_i + 2 \cdot t_{wall} = 17.07\ ft$ — *Outer diameter of penstock*

$$A_s := \frac{\pi \cdot \left(D_o^{\,2} - D_i^{\,2}\right)}{4} = 1.873 \cdot ft^2$$ *Area of penstock steel*

$A_w := \dfrac{\pi \cdot D_i^2}{4} = 227.0 \cdot ft^2$ *Cross sectional area of flow*

$w_s := \gamma_s \cdot A_s = 917.8 \cdot plf$ *Weight of penstock steel*

$w_w := \gamma_w \cdot A_w = 14163.6 \cdot plf$ *Weight of water*

$\boxed{DL1 := w_s = 918 \cdot plf}$ *Steel penstock dead load*

$\boxed{DL2 := w_w = 14164 \cdot plf}$ *Water dead load (Full pipe)*

$S_x := \dfrac{\pi \cdot \left(D_o^4 - D_i^4\right)}{32 \cdot D_o} = 13756 \cdot in^3$ *Section modulus of penstock*

$I_x := \dfrac{\pi \cdot \left(D_o^4 - D_i^4\right)}{64} = 1408903 \cdot in^4$ *Moment of inertia of penstock*

$\boxed{w_{LC3} := (DL1 + DL2) + w_{snow} = 16989 \cdot plf}$ *Uniform load (Load Combination 3)* *(CONTROLS)*

$w_{LC4} := (DL1 + DL2) + 0.75 \cdot LL + 0.75 \cdot w_{snow} = 16587.16 \cdot plf$ *Uniform load (Load Combination 6)*

$q_{DL} := \dfrac{w_{LC3}}{14.72 \cdot ft} = 8.01\ psi$ *Max pressure due to LC 3 - assuming spread over 120º top area, conservative*

Check External Loads on Penstock :

- Assume 2 feet of soil cover
- Assume no vehicular live loading

$\gamma_{soil} := \mathbf{120} pcf$ *Unit weight of soil*

$t_{wall} = 0.420 \cdot in$ *Wall thicknes (New penstock section)*

$ID := D_i = 17.00\ ft$ *Inner diameter of penstock*

$A_s := \dfrac{\pi\left[\left(ID + 2 \cdot t_{wall}\right)^2 - ID^2\right]}{4} = 269.73 \cdot in^2$ *Cross-section area of steel penstock*

$S_x := \dfrac{\pi\left[\left(ID + 2 \cdot t_{wall}\right)^4 - ID^4\right]}{32 \cdot \left(ID + 2 \cdot t_{wall}\right)} = 13756 \cdot in^3$ *Section Modulus*

$I_x := \dfrac{t_{wall}^3}{12} = 0.0741 \cdot \dfrac{in^4}{ft}$ *MOI of Steel Penstock (per unit length)*

$EI := E_{steel} \cdot I_x = 14.92 \cdot \dfrac{kip \cdot ft^2}{ft}$ *Pipe wall stiffness (per unit length)*

$h_{min} := \mathbf{2} ft$ *Minimum amount of soil cover above penstock*

Kleinschmidt Associates
Pittsfield, Maine

By: LLC Date: 6/3/2016
Checked by: _____ Date: ______

Determine Allowable Buckling Pressure for Soil Dead Load (per R2, Chapter 6):

$FS_{buck} := \mathbf{2.0}$ — *Bucking factor of safety*

$H := \dfrac{h_{min}}{ft} = 2.00$ — *Height of fill above penstock*

$B' := \dfrac{1}{1 + 4 \cdot e^{(-0.065 \cdot H)}} = 0.22$ — *Empirical coefficient of elastic support*

$R_w := 1.0$ — *Water buoyancy factor*

If coarse-grained soil WITH fines is assumed:

$E' := \mathbf{1200} psi$ — *Modulus of soil reaction (R2, Table 6-1)*
(Coarse-grained soil ***with fines****,* ***2ft cover****, 9****5%*** *relative compaction)*

Table 6-1 Values* of modulus of soil reaction, *E'* (psi) based on depth of cover, type of soil, and relative compaction

	Depth of Cover		Standard AASHTO relative compaction† 85%		90%		95%		100%	
Type of Soil†	*ft*	*(m)*	*psi*	*(kPa)*	*psi*	*(kPa)*	*psi*	*(kPa)*	*psi*	*(kPa)*
Fine-grained soils with less than 25% sand content (CL, ML, CL-ML)	2–5	(0.06–1.5)	500	(3,450)	700	(4,830)	1,000	(6,895)	1,500	(10,340)
	5–10	(1.5–3.1)	600	(4,140)	1,000	(6,895)	1,400	(9,655)	2,000	(13,790)
	10–15	(3.1–4.6)	700	(4,830)	1,200	(8,275)	1,600	(11,030)	2,300	(15,860)
	15–20	(4.6–6.1)	800	(5,520)	1,300	(8,965)	1,800	(12,410)	2,600	(17,930)
Coarse-grained soils with fines (SM, SC)	2–5	(0.06–1.5)	600	(4,140)	1,000	(6,895)	1,200	(8,275)	1,900	(13,100)
	5–10	(1.5–3.1)	900	(6,205)	1,400	(9,655)	1,800	(12,410)	2,700	(18,615)
	10–15	(3.1–4.6)	1,000	(6,895)	1,500	(10,340)	2,100	(14,480)	3,200	(22,065)
	15–20	(4.6–6.1)	1,100	(7,585)	1,600	(11,030)	2,400	(16,545)	3,700	(25,510)
Coarse-grained soils with little or no fines (SP, SM, GP, GW)	2–5	(0.06–1.5)	700	(4,830)	1,000	(6,895)	1,600	(11,030)	2,500	(17,235)
	5–10	(1.5–3.1)	1,000	(6,895)	1,500	(10,340)	2,200	(15,170)	3,300	(22,750)
	10–15	(3.1–4.6)	1,050	(7,240)	1,600	(11,030)	2,400	(16,545)	3,600	(24,820)
	15–20	(4.6–6.1)	1,100	(7,585)	1,700	(11,720)	2,500	(17,235)	3,800	(26,200)

$q_a := \left(32 \cdot R_w \cdot B' \cdot E' \cdot \dfrac{EI}{ID^3}\right)^{0.5} = 13.4 \, psi$ — *Allowable Buckling pressure (R2, eqn 6-7)*

Check Allowable Buckling Pressure Due to Maximum Soil Dead Load:

$q_{soil} := h_{min} \cdot \gamma_{soil} = 1.67 \, psi$ — *Maximum soil pressure on top of penstock*

$FS_{buck} = 2.00$ — *Required buckling factor of safety*

$check_{buckling} := if\left(q_{soil} \cdot FS_{buck} \le q_a, "OK", "No Good"\right)$ — $check_{buckling} = "OK"$

Computed buckling factor of safety: $\boxed{FS := \dfrac{q_a}{q_{soil}} = 8.04}$

Check Allowable Buckling Pressure Due to Maximum Soil Dead Load + Dead, Live, Snow:

$q_{DL} := \dfrac{w_{LC3}}{14.72 \cdot ft} = 8.01 \, psi$ — *Max pressure do to LC 3 Dead + Live + Snow*

$\text{check}_{\text{buckling2}} := \text{if}\left[\left(q_{soil} + q_{DL}\right)\cdot FS_{buck} \le q_a, \text{"OK"}, \text{"No Good"}\right]$

$\text{check}_{\text{buckling}} = \text{"OK"}$

Computed buckling factor of safety: $\boxed{FS := \dfrac{q_a}{q_{soil} + q_{DL}} = 1.38}$

SUMMARY *- Use CJP Groove Weld for weld repair. Penstock OK for buckling in buired condition. Also, unburied section (10-30ft long), top 120º +/- OK for this length and size of pipe.*

APPENDIX D

WELD TESTS

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NDT, Inspection and Engineering

NONDESTRUCTIVE EXAMINATION

To: **NEWFOUNDLAND HYDRO**
BAY D'ESPOIR NL

Page: **1 OF 1**

Date: **MAY 31/2016**
Acuren Job #: **183-16-10TAC003-0005**
Report #: **UT-MT053116-001 R0**
PO: **NA** WO: **NA**
Work Location: **BAY D'ESPOIR NL**

Attention: **KARL INKPEN**
Project: **PENSTOCK #1**
Item(s) Examined: **SEE BELOW**

Part #: **SEE BELOW** Material: **CARBON STEEL** Thickness: **BELOW**
Scope: **PERFORM UT AS PER CLIENT REQUEST.**
Type of Inspection: **Ultrasonic**

Test Details:

Acceptance Standard: **CLIENT INFO** Revision: **N/A**
Procedure/Technique: **CAN-UT-14P002** Revision: **06**
Type: **Flaw Detection** Method: **Contact**
Instrument: **Olympus** Model: **Epoch XT** S/N: **131476205** Cal Due: **JUNE 19 16**
Cal. Block: **IIW** S/N: **4875** Cable-Type: **COAXIAL** Length: **6'**
Cal. Block: S/N: Couplant: **SONOTECH UTX**

Probe & Technique Details:

	Test Angle (°)	Probe Type	Crystal Size	Freq. (MHz)	Serial Number	Damping Ω	Test From	Reference Reflector	Transfer Value	Reference dB	Reference % FSH	Scan dB	Range
1	**0**	**OLYMP.**	**½"**	**2.25**	**16040**	**NA**	**A**	**SBW**	**NA**	**45**	**40-60**	**+14**	**125mm**
2	**70**	**OLYMP.**	**½"**	**2.25**	**15263**	**NA**	**A/B**	**1.5mmSBW**	**NA**	**45**	**40-60**	**+14**	**125mm**

Test Surface Condition: **As Welded** Test Surface Temperature: **0°C to 50°C**

RESULTS:
Shear wave ultrasound inspection was carried out on the areas either side of the crack found in penstock #1 to determine overall length. The crack was determined to have a length of 29.5" long and starts 1.5" from the closest downstream circ weld. The crack follows the toe of the weld and on either end turns up into the parent material of the penstock (as seen in picture) A Magnetic particle inspection was also carried out see attached MT report.

Client Representative: N/A
Technician:

MIKE TRICKETT
1st Technician
CGSB II Reg. #14179

2nd Technician

Reviewer: Jane Matthews 05/31/16

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NONDESTRUCTIVE EXAMINATION

TO: NEWFOUNDLAND HYDRO
BAY D'ESPOIR NL

PAGE: 1 OF 1

DATE: MAY 31/2016
ACUREN JOB #: 183-16-10TAC003-0005
REPORT #: MT-MT053116-001 R0
PO: N/A WO: NA
WORK LOCATION: BAY D'ESPOIR NL

ATTENTION: KARL INKPEN
PROJECT: PENSTOCK #1
ITEM(S) EXAMINED: SEE BELOW

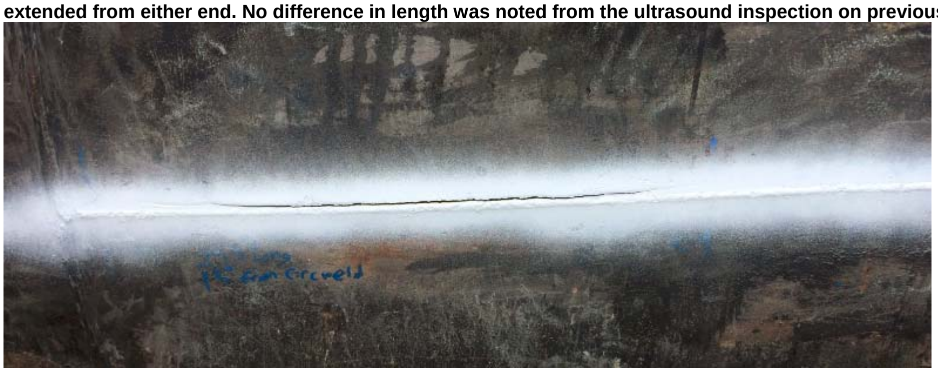
PART #: See below MATERIAL: Carbon steel THICKNESS: .437"
SCOPE: NDE as per client request
TYPE OF INSPECTION: Magnetic Particle

TEST DETAILS:

ACCEPTANCE STANDARD: CLIENT INFO REVISION: N/A
PROCEDURE/TECHNIQUE: CAN-MT-14P001 REVISION: R11 /2015

TYPE: Wet Visible	METHOD: Yoke
PARTICLE BRAND: Magnaflux PRODUCT NO.: 7HF	CURRENT: AC MT INSTRUMENT: Parker B-300
PARTICLE COLOUR: Black	MT INSTRUMENT S/N: 23490 CAL DUE: Oct 4 16
SUSPENSION: Oil	LIFT CHECK BEFORE USE: Yes LIFT WEIGHT S/N: 12846
CONTRAST PAINT: Magnaflux PRODUCT NO.: WCP2	LIGHTING EQUIPMENT: Flashlight
MAG TIME (SECONDS): 15 DEMAG REQUIRED?: No	BLACKLIGHT MAKE: N/A S/N: N/A
TECHNIQUE DEMONSTRATED OVER A PAINTED SURFACE?: N/A	LIGHT METER S/N: 150803637 CAL DUE: Oct 6 16
	LIGHT INTENSITY: Output > 100 fc
TEST SURFACE CONDITION: As Welded	TEST SURFACE TEMPERATURE: Oil -20°C to 50°C

RESULTS:
Magnetic particle inspection was carried out in the area on either side of the crack found in penstock #1 to ensure no surface cracks extended from either end. No difference in length was noted from the ultrasound inspection on previous report.



CLIENT REPRESENTATIVE: N/A
TECHNICIAN: [signature]
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2nd Technician

REVIEWER: Jane Matthews 05/31/16

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APPENDIX E

MT WELD INSPECTION REPORTS FOR NEW WELD

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NONDESTRUCTIVE EXAMINATION

TO: **NEWFOUNDLAND HYDRO**
BAY D'ESPOIR NL

PAGE: **1 OF 1**

DATE: **MAY 31/2016**
ACUREN JOB #: **183-16-10TAC003-0005**
REPORT #: **MT-MT053116-002 R0**
PO: NA WO: **NA**

ATTENTION: **KARL INKPEN**
WORK LOCATION: **BAY D'ESPOIR NL**
PROJECT: **PENSTOCK #1**
ITEM(S) EXAMINED: **SEE BELOW**

PART #: **See below** MATERIAL: **Carbon steel** THICKNESS: **.437"**
SCOPE: **NDE as per client request**
TYPE OF INSPECTION: **Magnetic Particle**

TEST DETAILS:

ACCEPTANCE STANDARD: **CLIENT INFO** REVISION: N/A
PROCEDURE/TECHNIQUE: **CAN-MT-14P001** REVISION: **R11 /2015**

TYPE: **Wet Visible**	METHOD: **Yoke**
PARTICLE BRAND: **Magnaflux** PRODUCT NO.: **7HF**	CURRENT: **AC** MT INSTRUMENT: **Parker B-300**
PARTICLE COLOUR: **Black**	MT INSTRUMENT S/N: **23490** CAL DUE: **Oct 4 16**
SUSPENSION: **Oil**	LIFT CHECK BEFORE USE: **Yes** LIFT WEIGHT S/N: **12846**
CONTRAST PAINT: **Magnaflux** PRODUCT NO.: **WCP2**	LIGHTING EQUIPMENT: **Flashlight**
MAG TIME (SECONDS): **15** DEMAG REQUIRED?: **No**	BLACKLIGHT MAKE: **N/A** S/N: **N/A**
TECHNIQUE DEMONSTRATED OVER A PAINTED SURFACE?: **N/A**	LIGHT METER S/N: **150803637** CAL DUE: **Oct 6 16**
	LIGHT INTENSITY: Output **> 100 fc**
TEST SURFACE CONDITION: As Welded	TEST SURFACE TEMPERATURE: Oil -20°C to 50°C

RESULTS:

Magnetic particle inspection was carried out on the inside of the penstock after a scaffold was erected. The inspection was done on the bottom side of the weld that was inspected earlier today after one of the welders noticed a sharp edge on the toe of the weld opposite the crack. The sharp edge was caused by the parent material being eroded away leaving an edge of weld metal this continues on intermittently approx. 6" upstream from the crack on the other side of the weld from the crack.

CLIENT REPRESENTATIVE: N/A
TECHNICIAN:
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REVIEWER: Jane Matthews
06/03/16

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NONDESTRUCTIVE EXAMINATION

TO: **NEWFOUNDLAND HYDRO**
BAY D'ESPOIR NL

PAGE: **1 OF 2**

DATE: **JUNE 2/2016**
ACUREN JOB #: **183-16-10TAC003-0005**
REPORT #: **MT-MT060216-001**
PO: NA WO: **NA**

ATTENTION: **KARL INKPEN**
WORK LOCATION: **BAY D'ESPOIR NL**
PROJECT: **PENSTOCK #1**
ITEM(S) EXAMINED: **SEE BELOW**

PART #: **See below** MATERIAL: **Carbon steel** THICKNESS: **.437"**
SCOPE: **NDE as per client request**
TYPE OF INSPECTION: **Magnetic Particle**

TEST DETAILS:

ACCEPTANCE STANDARD: **ASME SEC VIII** REVISION: **2015**
PROCEDURE/TECHNIQUE: **CAN-MT-14P001** REVISION: **R11 /2015**

TYPE: **Wet Visible**	METHOD: **Yoke**
PARTICLE BRAND: **Magnaflux** PRODUCT NO.: **7HF**	CURRENT: **AC** MT INSTRUMENT: **Parker B-300**
PARTICLE COLOUR: **Black**	MT INSTRUMENT S/N: **23490** CAL DUE: **Oct 4 16**
SUSPENSION: **Oil**	LIFT CHECK BEFORE USE: **Yes** LIFT WEIGHT S/N: **12846**
CONTRAST PAINT: **Magnaflux** PRODUCT NO.: **WCP2**	LIGHTING EQUIPMENT: **Flashlight**
MAG TIME (SECONDS): **15** DEMAG REQUIRED?: **No**	BLACKLIGHT MAKE: **N/A** S/N: **N/A**
TECHNIQUE DEMONSTRATED OVER A PAINTED SURFACE?: **N/A**	LIGHT METER S/N: **150803637** CAL DUE: **Oct 6 16**
	LIGHT INTENSITY: Output **> 100 fc**
TEST SURFACE CONDITION: As Welded	TEST SURFACE TEMPERATURE: Oil -20°C to 50°C

RESULTS:

MT was performed on items listed below at the time of inspection no rejectable indications were found.

MT was performed on the excavated area on the crack in penstock #1. The ends of the crack were ground out until indication was fully removed.

Down Stream end of cracked area after MT **Up Stream end of cracked area after MT**

The Client Representative who receives this report is responsible for verifying that the acceptance standard listed in the report is correct, and promptly notifying Acuren of any issues with this report and/or the work summarized herein. The owner is responsible for the final disposition of all items inspected.

CLIENT REPRESENTATIVE: N/A

TECHNICIAN: [signature]
Mike Trickett
1st Technician
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2nd Technician

REVIEWER: Jane Matthews
06/03/16

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NONDESTRUCTIVE EXAMINATION

TO: **NEWFOUNDLAND HYDRO**
BAY D'ESPOIR NL

PAGE: **2 OF 2**

DATE: **JUNE 2/2016**
ACUREN JOB #: **183-16-10TAC003-0005**
REPORT #: **MT-MT060216-001**
PO: NA WO: **NA**

ATTENTION: **KARL INKPEN**
WORK LOCATION: **BAY D'ESPOIR NL**
PROJECT: **PENSTOCK #1**
ITEM(S) EXAMINED: **SEE BELOW**

RESULTS:

After root was welded and cleaned up MT was performed, no rejectable indications were found.

Root Area MT

The weld was then filled and caped on the outside of penstock. The backing bar was then removed from the inside of the penstock and the root was cleaned and final cap was welded.

Cap on inside

Cap on outside

CLIENT REPRESENTATIVE: N/A

TECHNICIAN: Mike Trickett
1st Technician
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CGSB Reg. #14179

2nd Technician

REVIEWER: Jane Matthews 06/03/16

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Newfoundland and Labrador Hydro

Root Cause Analysis Report

For

Bay d'Espoir Penstock No. 1 Refurbishment

H352666-00000-220-066-0002
Rev. 1
March 17, 2017

Newfoundland and Labrador Hydro

Root Cause Analysis Report

For

Bay d'Espoir Penstock No. 1 Refurbishment

H352666-00000-220-066-0002
Rev. 1
March 17, 2017

HATCH

Newfoundland and Labrador Hydro
Bay d'Espoir Penstock No. 1 Refurbishment
H352666

Engineering Report
Mechanical Engineering
Root Cause Analysis

Report

Root Cause Analysis

H352666-00000-220-066-0002

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REGISTERED PROFESSIONAL ENGINEER
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GREGORY SAUNDERS
SIGNATURE
March 17, 2017
DATE
NEWFOUNDLAND & LABRADOR

2017-03-17	1	Final	M. Pyne	D. French	G. Saunders
DATE	REV.	STATUS	PREPARED BY	CHECKED BY	APPROVED BY

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Appendix B **Weld Coupon #2 Test Report**

Appendix C **Weld Coupon #3 Test Report**

Appendix D **Bay d'Espoir Pressure Conduit #1 Inspection Report 1987**

Appendix E **Water Chemistry Reports**

Appendix F **Acuren Test Reports**

Appendix G **Backfill Calculations**

Appendix H **NL Hydro Drawing No. 10830-2 Penstock No. 1 Intake to Surge Tank**

1. Introduction

Hydro engaged Hatch on September 22, 2016 to investigate the condition of some of the welded joints on Bay d'Espoir Penstock No. 1. In September of 2016, Penstock No. 1 experienced a failure to one of the longitudinal welded joints. The joint was repaired, but further inspection by Hydro indicated there were problems with other longitudinal joints.

Upon completion of the inspection plan developed by Hatch, it was confirmed that the majority of the longitudinal weld joints from the intake down to Section 117 (Refer to Appendix H), approximately 900 m of penstock seams, had experienced a significant amount of weld metal loss.

As a result of the recent repairs to the welded joints and the amount of weld metal loss to the longitudinal seams, Hydro requested Hatch to complete a Root Cause Analysis (RCA) on the problem.

The purpose of the RCA is to, where possible, identify any design, metallurgical, operational and environmental factors that either separately or collectively caused the corrosion issues, which have been found through inspection, in the longitudinal weld joints and resulted in the failure of the longitudinal joints.

Incidents and improvement opportunities may arise anywhere in an organization and can vary a great deal in nature, severity or impact, or underlying causes. Despite the large range of issues and conditions, the same basic process is applicable to any improvement/problem solving initiative. The RCA is a multi-step process, and generally involves the following:

- Data Collection
- Defining the factors
- Root Cause Identification
- Recommendations

2. Data Collection

The following data was collected to determine the factors that caused and/or accelerated the failures:

1. Drawings of Penstock No.1.
2. Material properties were identified from the drawings and samples from the penstock shell plate and welds were tested.
3. Kleinschmidt Crack Investigation and Repair Report Penstock No. 1 Bay d'Espoir Hydroelectric Development, June 2016.
4. Bay d'Espoir Pressure Conduit #1 Inspection Report 1987.
5. Water and Organic growth samples were collected and tested.
6. Discussions with engineering and operations personnel.
7. Internal inspections of penstock and welding seams.
8. External inspections of backfill.

3. Failure Factors

3.1 Construction Methods

Penstock No.1 is constructed from a series of cans that vary in length depending on location, but in general the cans are approximately 9 ft long. Each can consists of two rolled steel plates that are welded together longitudinally. This form of assembly requires two longitudinal welded joints.

The penstock varies in diameter from 17 ft to 15 ft 3", and the thickness varies depending on the location. The penstock is also constructed of two grades of steel, ASTM 285 Gr. C steel from the intake up to and including section 16, and CSA G40.8 Gr. B. for the remainder.

During the era in which Penstock No. 1 was constructed, plate rolling was generally completed utilizing a three roll single pinch point roll. When rolling plates with this type of roll, the start and end of each plate will be flat. Figure 3-1 shows an exaggerated peaking (in red) compared to the desired tubular structure (in blue).

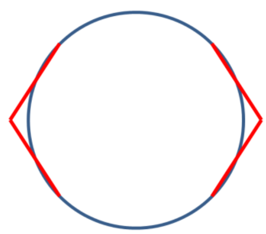


Figure 3-1: Peaking (Red) As Welded (Blue)

Difficulties with lining up the longitudinal seams at the time of construction in the 1960s are evident when examining the internals of the penstock and seeing evidence of extensive dogging[1] of the joints to bring the longitudinal seams together. The flat spots and induced stress from fitting the straight ends increase the residual stress at the joints. Below is an image of the longitudinal seam that failed in September. Large amounts of peaking were observed at the initial crack location, see Figure 3-2, and this would mean the weld was resisting significant residual stresses to maintain a round shape at the seam. The increased stress also makes the longitudinal joints more susceptible to material loss as they become sensitized to corrosion.

[1] Utilization of welded horseshoe shaped brackets and wedges to force plates into alignment prior to welding and to limit distortion during welding.

Figure 3-2: Longitudinal Weld Failure Showing Peaking

3.2 Internal Coating

The existing internal coating is original to the penstock and was specified as a two coat system manufactured by The Standard Manufacturing Company of Newfoundland. The primer coat consisted of 5 mils dry film thickness (DFT) of Matflint #7-Primer and the finish coat was 6 mils dry film thickness of Matflint #7-Black Coal Tar Epoxy (Bay d'Espoir Pressure Conduit #1 Inspection Report 1987).

After a review of a previous inspection report, it is evident that initial coating deterioration occurred prior to 1987 and the deterioration has steadily progressed since then. In the report it also mentions that failure of the coating initiated at the welds. This inspection also completed a review of the interior surface but did not identify any excessive corrosion of the longitudinal joints and did not make any recommendations for further inspection or refurbishing of the corroded areas.

Visual inspection of the penstock interior surface indicated some of the coating to be present; however, a physical inspection showed there was no bond between the coating and the steel, as the coating was easily lifted off by scraping the surface. Visual inspection of all exposed surfaces (welds and parent metal) showed varying signs of pitting corrosion which is typical for a penstock of this age.

At the time of construction (1960's), Coal Tar Epoxies were being utilized as one of the industry standards for penstocks internal protection coatings on penstocks (Centre for Energy Advancement through technological Innovation (CEATI) Technology Review Hydro-Electric Coating Strategies for Corrosion Prevention). Penstock guidelines and best practices commonly reference internal coatings per AWWA C203 Standard for Coal-tar Protection Coatings and Linings (Steel Penstocks 2012 (2nd Edition)).

In general, coal tar epoxy coatings have a lifespan of 10-20 years depending on the service. For internal penstock coating, in particular, CEATI estimates the expected life for this particular system to be on average 15 years. The coating on penstock No. 1 has been in place since the original installation and has exceeded the standard life expectancy.

Failure modes for Coal Tar Epoxy coating systems are typically as outlined below. However, due to lack of available information from the original fabrication/construction we cannot determine if either of these contributed to the coating failure:

1. Insufficient surface preparation. Surface preparation needs to be completed on the entire internal surface including welds. In other industries we have seen instances where welds were insufficiently prepped which leads to localized coating failure along weld seams. This localized failure allows the spread by water getting behind the coating and "lifting" the coating and therefore progressing the failure outward from the welds.
2. Insufficient curing time/environment. Coal tar epoxies are typically high DFT (approximately 10-14 mils) systems built up in multiple coats. Typical DFT of a single coat should not exceed 3-4 mils. Thicker coats should be avoided as it causes increased curing times and possible curing issues. It is possible that the system was applied in two thick coats, leading to improper curing.
3. As coal tar epoxies age, they become brittle and crack. This embrittlement and cracking allows localized failures which eventually lead to moisture penetrating the system and ultimately system failure. This embrittlement and cracking would be exacerbated by any dimensional changes from increasing/decreasing ovality. The penstock tends to flatten during extended periods of being de-watered (the degree of which is directly related to the exterior backfill support), but rounds out after re-pressurizing.

3.3 Organic Growth

The internal surface of Penstock No. 1 has a layer of organic growth, approximately 2 inches thick, extending from the intake to Section 117. The layer of organic growth reduces in thickness as you progress downstream towards the powerhouse. The penstock (welds and parent metal), downstream of the surge tank, appeared to be corroding at a rate that would be expected for similar penstocks without a protective coating. When inspecting the penstock in the scroll case area the organic growth was not present and corrosion was substantially reduced with no signs of accelerated pitting corrosion of the weld metal or heat affected zone (HAZ).

To assess the possibility of microbiologically influenced corrosion (MIC) a series of organic samples were taken and sent for testing. The following organic tests were performed by Acuren, Mississauga, Ontario.

- Low Nutrient Bacteria (LNB)
- Iron-Related Bacteria (IRB)
- Anaerobic Bacteria (ANA)
- Acid-Producing Bacteria (APB)
- Sulfate-Reducing Bacteria (SRB)

In general, microbiologically influenced corrosion testing is completed on wetted specimens; this allows standard testing to be completed. Final readings of testing indicate the following:

- Negative readings for IRB and SRB
- Weak Positive readings for LNB, ANA and APB

Based on these findings it would appear that the organic growth provides an environment that is more susceptible to pitting corrosion and allows ions to flow more freely.

3.4 Water Analysis

Water testing data was collected from 1965, 1980, 1988, 1992, 1993, 1994, 1995, 1996 and 2016. Testing between 1965 and 2016 yielded similar Langelier saturation index (LSI) results. However, the most recent water test indicates a change in water chemistry. We recommend additional testing to confirm these results.

The available data from 1965-2016 was used to compute the LSI, which is used to quantify the corrosive behavior of a specific water source. This calculation takes the pH, alkalinity, Total Dissolved Solids (TDS), temperature and calcium all into account rather than strictly depending on the pH value.

The LSI ranks water corrosion potential on a scale typically between -5 to 4, with -5 being highly corrosive and 4 having a high likely hood of scale buildup. When applying the LSI to the Bay d'Espoir water samples the following values were obtained:

Table 3-1: LSI vs Water Sample Year

Year	LSI	Year	LSI
1965	-4.77	1994	-5.72
1980	-6.57	1995	-5.69
1988	-5.02	1996	-4.75
1992	-5.71	-	-
1993	-5.65	2016	-3.9

In several instances the LSI ratings calculated were outside of the typical range, indicating the water is more corrosive than typical water bodies. These values would indicate that the water flowing through the penstock would be considered highly corrosive. Refer to Appendix E for further information on samples and the LSI index.

3.5 Base Metal and Weld Analysis

Throughout the upper section of the penstock it was noted that longitudinal seams were experiencing extensive pitting corrosion, material loss and well defined notches along the heat affected zone of the welds. This excess material loss and notching contributes to high stresses, crack initiation and propagation. Refer to Figure 3-3 and Figure 3-4 for images of the notching, excessive pitting corrosion, and material loss.

Figure 3-3: Longitudinal Seams in Penstock No.1 Section 16

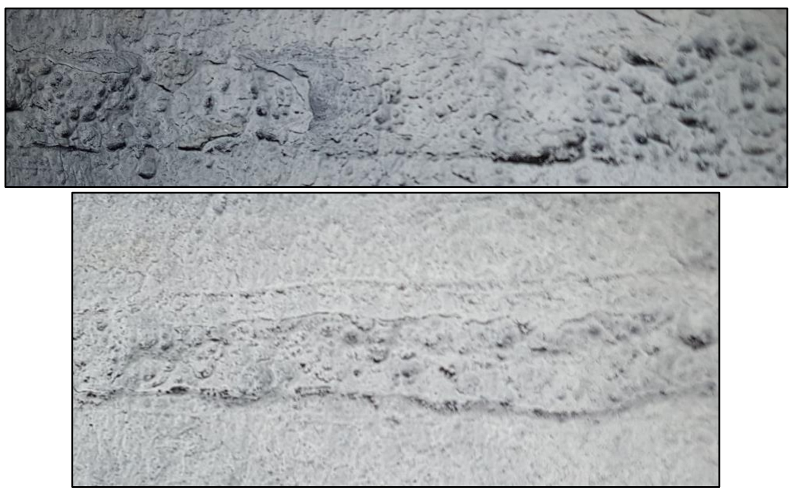


Figure 3-4: Longitudinal Seams in Penstock No.1 Section 16

To assess the metallurgy, mechanical and chemical properties of the parent metal and weld metal, a series of non-destructive and destructive testing was carried out.

The following non-destructive testing (NDT) was performed by TEAM Industrial Services, St. John's, NL, to aid the RCA investigation:

- Radiographic Examination

The following destructive testing was performed by Cambridge Materials Testing Limited, Cambridge, Ontario, to aid the RCA investigation:

- Microetch Evaluation
- Macroetch Evaluation
- Vickers Hardness Traverse
- Transverse Weld Tensile
- Weld Metal Chemical Analysis Test
- Base Metal Chemical Analysis Test

The following destructive testing was performed by Acuren, Mississauga, Ontario, to aid the RCA investigation:

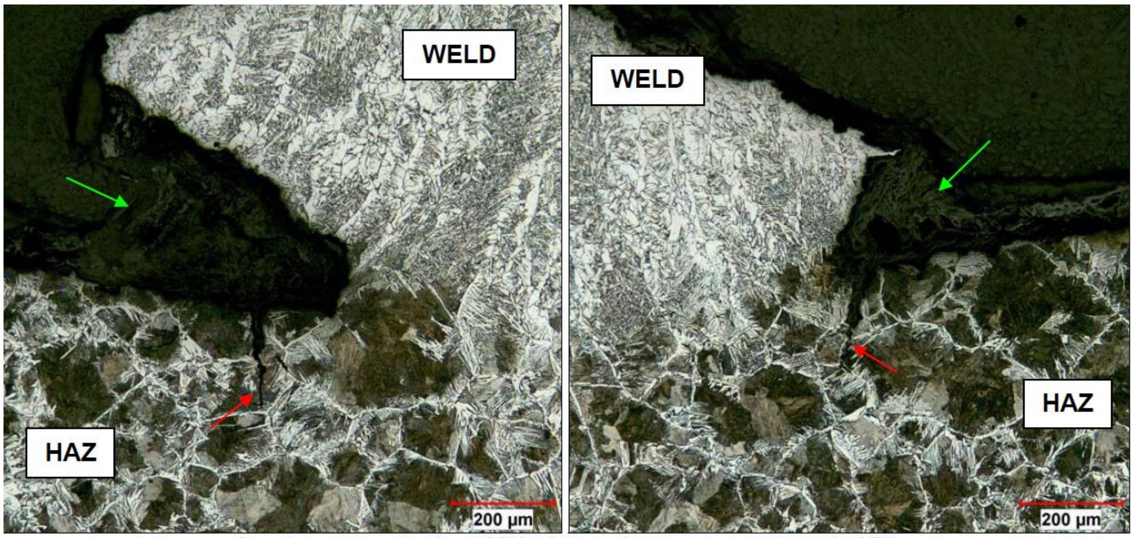
- Potential Difference Measurements (Weld/Base Metal Galvanic Testing)

The above tests were completed for three separate coupons:

1. Longitudinal seam between ASTM 285 Gr. C (Coupon #1 Section 16)
2. Circumferential seam between CSA G40.8 Gr. B (Coupon #2 Section 17)
3. Circumferential seam between ASTM 285 Gr. C (Coupon #3 Section 8)

Detailed results of the testing can be found in Appendix A, B & C. The Vickers Hardness test, weld tensile test, and chemical analysis are all consistent with the base metals listed on the design drawings and shield metal arc (SMAW) E4918 welding consumables.

As indicated in the attached reports, both the weld metal and parent metal are high in Sulphur. High amounts of Sulphur, by itself, can produce porosity in the weld metal and heat affected zones, primarily at the surface. Surface porosity is one of the main contributors to pitting corrosion. The presence of pitting corrosion would accelerate the effects of preferential corrosion and stress corrosion cracking.



Specimen examined at 100X, photos shown at approximately 85X
Etched in 2% Nital

Figure 3-5: Coupon #1 Micro of Heat Affected Zone Transgranular Cracks

The macroetch and microetch of coupon #1 (longitudinal) show surface pitting corrosion and advanced stages of preferential pitting corrosion with cracks initiated from the cavities and are progressing through the heat affected zone.

The macroetch and microetch of coupon #2 & 3 (circumferential) show surface pitting corrosion and preliminary stages of preferential pitting corrosion without any cracks.

The results of the Weld/Base Metal Galvanic Testing generally indicate that a galvanic cell between the weld metal and base metal is present and the weld metal, in particular the heat affected zone, was more susceptible to pitting corrosion than the base metal.

3.6 Weld Seam Stresses

Penstock pressure from the static head or dynamic head cause stresses in the penstock shell that can be categorized as “longitudinal stress” and “hoop stress”, which occur simultaneously. The “hoop stress” is twice as high as the “longitudinal stress”. The “hoop stress” is the stress found in the longitudinal joints. The stress in circumferential weld seams is known as the “longitudinal stress”. As a result, virtually all failures in penstocks or pressure piping where there is a crack or split in a seam occur in the longitudinal direction.

3.6.1 Stress in Longitudinal Joints "Hoop Stress"

Longitudinal seams are more susceptible to failure due to higher stresses.

The stress in longitudinal weld seams is known as the "hoop stress". The "hoop stress" (σ_h) is dependent upon the pressure (P), diameter (D) and wall thickness (t).

$$\sigma_h = \frac{PD}{2t}$$

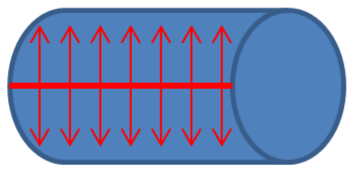


Figure 3-6: "Hoop Stress" Pulls Longitudinal Seams Apart

3.6.2 Stress in Circumferential Joints "Longitudinal Stress"

Circumferential seams are less susceptible to failure due to lower stresses.

The stress in circumferential weld seams is known as the "longitudinal stress". The "longitudinal stress" (σ_L) is dependent upon the pressure (P), diameter (D) and wall thickness (t).

$$\sigma_L = \frac{PD}{4t}$$

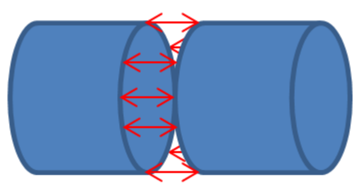


Figure 3-7: "Longitudinal Stress" Pulls Circumferential Seams Apart

3.7 Backfill

When reviewing the backfill requirements of Penstock No. 1 it was noted that there is a difference between the design specification and the "As Built" drawings. The specification states the penstocks were to be covered with soil to a minimum depth of 3 ft. The "As Built" drawing, Figure 3-8 is similar to the condition currently found in the field. The surrounding fill is part of the penstock construction, and serves to keep the penstock in shape when it is unwatered, to prevent collapse due to the pressure in the penstock falling below atmospheric, and by insulating to prevent excessive thermal stresses.

The “As Built” drawing shows a detail that has cover thicknesses in multiple locations below 1 ft.

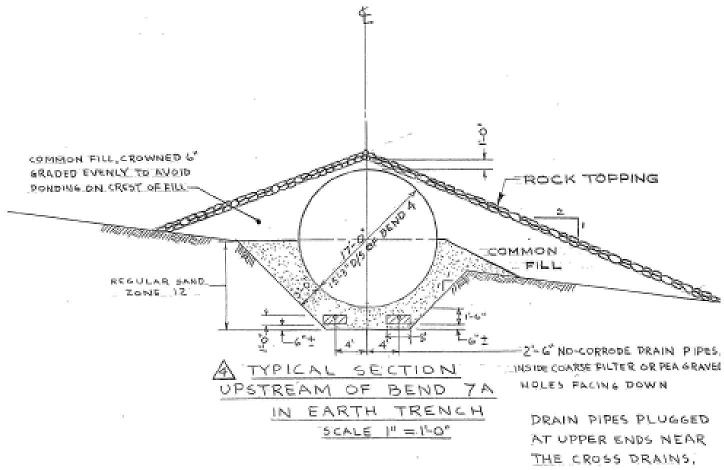


Figure 3-8: Drawing Half Trench as per “As Built” Drawing

Current reference material shows typical half trench buried penstock cover details (Buried Steel Penstocks – Steel Plate Engineering Data –Volume 4) of 2 ft minimum of cover and can be seen below:

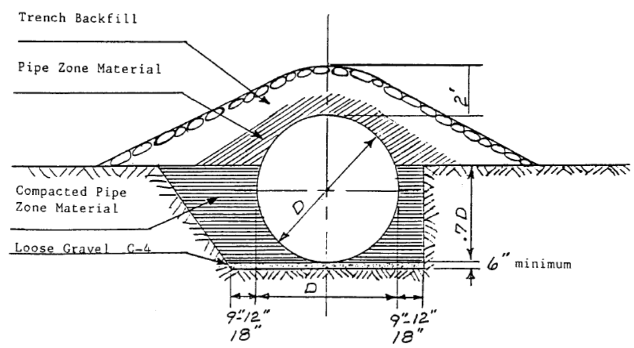


Figure 3-9: Typical Half Trench

When analyzing the backfill it was determined that backfill is structurally integral to the penstock and provides needed support along the center line. In the area where the penstock cracks occurred, the depth of backfill is less than 2 ft and some sliding and sloughing of the backfill has occurred. This has been shown to increase the stress level by approximately 100% in the area of longitudinal welds locations. Refer to the finite element stress analysis completed for the backfilling of the excavated areas in Appendix G.

4. Heat Affected Zone Pitting Corrosion Contributing Factors

The results of the testing included in the preceding sections indicate that the longitudinal seams, from the intake downstream to Section 117, experienced weld metal loss, primarily in the heat affected zone, attributed to “Preferential Heat Affected Zone Pitting Corrosion”.

The problem arises from the fact that weld metal compositions (which are normally optimized for mechanical properties) tend to be slightly anodic to the parent steel. This issue arises across all welded structures. Therefore, the weld metal corrodes at a higher rate than the base metal.

The preferential corrosive attack of welds can occur for a number of reasons:

1. Differences in composition between the weld metal and the base metal can generate a potential difference in certain environments, thus setting up a galvanic cell, leading to pitting corrosion.
2. Differences in as-welded microstructure could make the weld metal sufficiently different from and even less corrosion resistant than the base metal.
3. Microstructural differences between the base metal and as-welded heat affected zones can lead to localized attack of the heat affected zone.
4. Preferential pitting corrosion is more prone to occur when the weld metal is exposed to aqueous environments that are fairly high in conductivity, and can occur at pH values below approximately 7 to 8 (Indicating low LSI numbers). Historical data (recorded for NL Hydro) indicates pH levels as low as 5.2 (Appendix E). In addition, the microbiologically influenced corrosion causing bacteria in the organic growth, and the sulfur content in the base metal and weld metal could accelerate pitting corrosion.
5. Due to the construction methods of the penstock, the longitudinal seams would have inherent residual stresses that would be intensified by the heating and cooling of the welding process. High residual stresses can contribute to another phenomenon known as “Stress Corrosion Cracking” which would exacerbate the preferential pitting corrosion and contribute to the reasons why the longitudinal seams experienced a more accelerated corrosion rate than the circumferential seams. Due to the construction methods, the circumferential weld seams would experience lower residual stresses.

5. Identification of Root Cause

Although the method or tool used to conduct RCA varies, the principle is the same regardless of the tool used. Methods and tools should be selected in accordance with the particular problem requirements. In this case, an Events and Casual Factor Analysis was completed. A Casual Factor Summary Table (see below) was generated to organize the information by the defining factors, their primary effects and their contribution to the Root Cause Mapping.

Table 5-1: Corrosion Casual Factor Summary Table

Defining Factor	Primary Effect	Root Cause Mapping
Construction Methods	High residual stresses	High residual stresses combined with exposure to harsh environments lead to stress corrosion cracking.
Internal Coating	Failure of coating	Exposure to harsh environment.
Organic Growth	Generates microbiologically influenced corrosion (MIC)	Presence of microbiologically influenced corrosion (MIC) amplifies harsh environment
Water Analysis	Low Langelier Saturation Index numbers	Confirmed harsh environment exists
Base Metal and Weld Metal Analysis	High Sulphur in base metal and weld metal.	High susceptibility to porosity and pitting corrosion when exposed to harsh environment.
	Galvanic couple between heat affected zone and base metal	Heat affected zone acts sacrificially to base metal and weld metal when exposed to harsh environment.
Weld Seam Stresses	High operating stresses in longitudinal seams	Increases sensitivity to pitting corrosion when exposed to harsh environment.
Backfill	Insufficient backfill and sloughing leads to high stresses.	High stresses increases sensitivity to pitting corrosion when exposed to harsh environment.

In this case, the analysis links the “exposure to the harsh environment” as a path through the Root Cause Mapping to all of the casual factors. The primary effect that leads to the “exposure to the harsh environment” is the failure of the internal coating system.

Table 5-2: Cracking Casual Factor Summary Table

Defining Factor	Primary Effect	Root Cause Mapping
Corrosion (Table 5-1)	Material loss	Reduced thickness of longitudinal seams below critical values.
	Notching along heat affected zone	Intensified stresses along longitudinal weld seams.
Weld Seam Stresses	High operating stresses in longitudinal seams	Reached critical stress due to insufficient material and notching which lead to failure.
Backfill	Insufficient backfill and sloughing leads to high stresses.	Reached critical stress due to insufficient material and notching which lead to failure.

The Casual Factor Summary Table links reaching the critical stress to the material loss and notching.

6. Conclusions

This report addresses two predominant issues, the pitting corrosion of the longitudinal seams in the section of the penstock located between the intake and the surge tank, and the failure of the longitudinal seams resulting in two cracks.

The section of the penstock that is located between the surge tank and the powerhouse is corroding as the original coating is no longer effectively protecting the steel, but at a rate that is normal for uncoated penstocks. There are no signs of excessive pitting corrosion of the longitudinal welds in this area. There is no reason to be concerned provided this section of the penstock is inspected to ensure the corrosion rate remains the same.

6.1 Penstock Pitting Corrosion

The interior of the penstock was originally coated with a coal tar epoxy that protected the interior surface. The coating has exceeded the normal service life of this type of product and no longer protects the interior surface of the steel penstock.

In general, the entire interior of the penstock is no longer protected from corrosion by a coating system. The corrosion attack is primarily focused on the longitudinal weld seams in the weld and heat affected zones. Based on our analysis, in our opinion the penstock is experiencing stress corrosion cracking.

Stress corrosion cracking requires two main contributing factors:

1. Harsh environment

The water flowing through the penstock has a low pH and a low LSI making it a harsh environment. Further to this, a microbiologically influenced corrosion generating organic growth has attached itself to the interior surface which also adds to the harshness of the environment.

2. High stresses

The high stresses in the longitudinal weld seams causes stress corrosion sensitization. This can be broken down into three factors:

- High residual stresses in longitudinal joints from fabrication, which was common fabrication practice at the time of construction.
- Insufficient/sloughing backfill
- Longitudinal joints have higher stresses than circumferential joints due to “hoop stress”.

These factors have made the longitudinal seams the primary point for corrosion attack in the penstock.

Further corrosion accelerants were found during the investigation:

- The metallurgy also contributed to the susceptibly to corrosion. After completing a chemical analysis, it was determined that the weld metal and base metal used during construction, were both high in Sulphur. This high Sulphur can increase pitting corrosion and exacerbate stress corrosion cracking.
- Galvanic testing also indicated a galvanic couple that caused pitting corrosion in the heat affected zones.

Each of these factors could cause or accelerate the pitting corrosion when the weld metal and base metal were exposed to a harsh environment.

6.2 Penstock Cracks

The probable cause of the failure of the longitudinal seam was a function of the general corroded condition of the welds and the location of the joint.

The failed joint occurred in the highest pressure area of the largest diameter portion of the penstock and in an area with the least amount of backfill.

The existing backfill in the area of the cracked joints provided insufficient cover due to local sloughing/sliding of the fill material.

Consequently due to high stress concentrations along the weld seam due to pitting corrosion, a reduced thickness of heat affected zone metal, high pressure stress due to hydraulic head and lack of backfill support in the area, the metal reached a critical stress and failed.

7. Recommendations

The objective of root cause analysis is to identify the underlying cause(s) that led to the problem so that these root cause(s) can be potentially eliminated for this and other penstocks. By treating the root cause(s) and not just the symptoms, future occurrences can be prevented.

Since the major contributing factor to the pitting corrosion of the welds is “exposure to the harsh environment”, and its root cause is “failure of the internal coating system”, the primary recommendation is to reinstate the coating system.

The original design of the penstock included a coal tar epoxy coating. In our opinion, due to the corrosive nature of the water, organic growth and identified corrosion problems the entire length of the penstock should be coated with a suitable corrosion resistant system. The recommended timeline for this work is within the next 5 years.

Other mitigating alternatives were considered, such as cathodic protection, and treating the water to raise the pH and minimize the organic growth. However, attaching anodes to the interior of a penstock creates a hazard to the turbine equipment and the volume of water flowing through the penstock makes water treatment impractical.

Based on a preliminary review of the design of the penstock and backfill interaction, we have determined the backfill is integral to the structural integrity of the penstock. Hatch determined through analysis that even small excavated areas are required to be reinstated prior to watering up the penstock. Visual inspection of the backfill in the area where the re-welding and crack repairs occurred indicated there is a possible interrelationship between the location of the cracks and the condition of the backfill. Hydro is currently having an assessment of the backfill design completed by Hatch to confirm the required backfill cross section. Further recommendations will be detailed in this assessment.

We anticipate there could be similar corrosion issues in Penstocks No. 2 and No. 3 as were found in Penstock No. 1. These three penstocks were designed, fabricated and installed by the same contractor and used identical materials in their construction.

There is one marked difference between these two penstocks and Penstock No. 1, and that is the backfill. There does not appear to be the same sloughing and sliding of the backfill for Penstocks No. 2 and No. 3, thus the stresses in the longitudinal joints is anticipated to be less.

These penstocks have a different profile due to the bedrock elevation at each location. Hatch will be assessing the stresses in these two penstocks due to their backfill and providing recommendations if any remedial action is required.

For all Hydro’s penstocks throughout the province that have been internally coated, we recommend that Hydro implement inspection procedures that check the functional quality of any internal coatings system to ensure there is sufficient adhesion of the coating to the steel and there is no underside corrosion occurring. This may require inspection procedures that are in accordance with the National Association of Corrosion Engineer (NACE) and removal of some of the coating in areas of high stress.

8. References

1. ASCE Steel Penstocks 2012, Manuals and Reports on Engineering Practice No. 79.
2. CEATI Technology Review Hydro-Electric Coating Strategies for Corrosion Prevention.
3. ASME OM SG 3.
4. Buried Steel Penstocks Steel Plate Engineering Data Volume 4.
5. PLP-131-020-0004 Hatch Root Cause Analysis Method.

Appendix A
Weld Coupon #1 Test Report

1. Introduction

As part of the Root Cause Analysis (RCA) investigation a coupon measuring approximately 460 mm x 460 mm (18” x 18”) was removed from Section 16 (A285 Gr C Material) of BDE Penstock #1. The coupon incorporated a portion of one of the longitudinal weld seams that was partially repaired by Hydro’s personnel, but did not include the repaired section.

2. Required Tests

The following non-destructive testing was performed by TEAM Industrial Services, St. John’s, NL, to aid the RCA investigation:

- Radiographic Examination

The following destructive testing was performed by Cambridge Materials Testing Limited, Cambridge, Ontario, to aid the RCA investigation:

- Macroetch Evaluation
- Vickers Hardness Traverse
- Microetch Evaluation
- Transverse Weld Tensile
- Weld Metal Chemical Analysis Test
- Base Metal Chemical Analysis Test
- Coating System Asbestos and Quantitation Test

3. Test Results

Radiographic Examination

The radiographic examination showed no rejectable defects. Porosity was detected, but was in the range of acceptable limits.

Macroetch Evaluation

A Photomacroetch of the weld was prepared from two different sections of the coupon etched in 2% Nital. A stereo microscope was then used to examine the samples for general comments on weld imperfections.

- Both sections showed a profile consistent with “Preferential Heat Affected Zone Corrosion”.
- Both sections exhibited cracks propagating from the toes of the weld.

- One section exhibited porosity on the face of the weld.

Microstructural Examination

The two sections used in the previous Vickers hardness traverse were re-prepared according to ASTM E3-11 for microstructural examination. The specimens were etched in 2% Nital and examined using an optical microscope at various magnifications. The examination was performed at and near the fusion line locations on either side of the weld, where cracks were observed in the macroexamination.

- Microstructure examination showed ferrite and pearlite in both specimens.
- Both specimens displayed a relatively coarse grain HAZ on either side of the FL locations.
- Both specimens displayed a more refined structured HAZ consisting of fairly uniform mixture of pearlite and ferrite on the FL+1mm locations.
- Viewing at a higher magnification, cavities can be seen at both weld toes. Both cavities were filled with corrosion product.
- Transgranular cracking was present within the corrosion cavities. Both cracks were propagating through the HAZ.

Vickers Hardness Traverse

Both macroetch sections were re-polished according to ASTM E3-11 and subjected to a Vickers Hardness Traverse. The Vickers Hardness readings were performed according to ASTM E92-16 using a 10kgf test force and indentations were measured at 100x magnification.

- Hardness values for the weld metal ranged from 169 to 198
- Hardness values for the HAZ ranged from 143 to 173
- Hardness values for the Base material ranged from 139 to 151

Hardness values are within the range of normal expected values for this type of material and E4918 (E7018) welding consumables.

Transverse Weld Tensile

- Ultimate Tensile Strength (UTS) of base metal = 69.5 ksi (480MPa)

The tensile specimen fractured in the base metal indicating the UTS of the weld metal meets the requirements of being higher than the UTS of the base metal.

Weld Metal Chemical Analysis

The chemistry indicated on the attached report is consistent with an E4918 (E7018) electrode.

The sulphur content is below the maximum allowable of 0.035% (CSA W48, Table 1); however, according to Lincoln and Air Liquide specification sheets, the normal level of sulphur in the deposited weld metal for standard SMAW electrodes is 0.008% to 0.013% with E4918 (E7018) normally around 0.011%. Thus, even though the sulphur content is below the maximum allowable, it is 2X the normal percentage.

Base Metal Chemical Analysis

The base metal chemistry is consistent with ASTM A285 Gr C material.

Coating System Asbestos and Quantitation Test

Coating system was identified as a Coal Tar Epoxy.

No presence of asbestos was detected in the coating system.

Attachment A
Test Results

Cambridge
materials testing limited

1177 Franklin Boulevard,
Cambridge, Ontario N1R 7W4
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www.cambridgematerials.com

Report For:	TEAM Industrial Services (NFLD) 41 Sagona Avenue MOUNT PEARL, Newfoundland A1N 4P9	**Laboratory #:** **Report Date:** **Received Date:**	**739108-16** October 27, 2016 October 17, 2016
Attention:	Keith Gowan	**Customer P.O.#:**	
Specimen:	For Hatch Limited, “Penstock” Weld Pipe Coupon		

MACROETCH EVALUATION TEST REPORT

Two random transverse sections were cut from the submitted weld coupon and prepared according to ASTM E3-11. The sections were arbitrarily labelled Section 1 and Section 2 by CMTL. The sections were etched in 2% Nital and then examined using a stereo microscope for general comments on weld imperfections.

RESULTS

Section 1: Examination of the specimen showed that the weld had discontinuities at both toes and porosity on the face on one side of the weld (refer to Figure 2). At higher magnification, the discontinuities at the toes of the weld were revealed to be cracks propagating along the fusion line of the weld (refer to Figure 3). The weld appeared to have no undercut or inclusions, and there was complete penetration and complete fusion observed throughout the weld.

Section 2: Examination of the specimen showed that the weld had discontinuities at both toes on one side of the weld (refer to Figure 4). At higher magnification, the discontinuities at the toes of the weld were revealed to be cracks propagating along the fusion line of the weld (refer to Figure 5). The weld appeared to have no porosity, undercut or inclusions, and there was complete penetration and complete fusion observed throughout the weld.

Cambridge Materials Testing Limited

Per Randi Lee
Randi Lee *Quality Assurance*

Per Dan Bielby
Dan Bielby *Technician*

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VICKERS HARDNESS TRAVERSE TEST REPORT

The macroetch sections were then re-polished according to ASTM E3-11 and subjected to a Vickers hardness traverse (refer to Figure 1). The Vickers hardness readings were performed according to ASTM E92-16 using a 10kgf test force. Indentations were measured at 100X magnification.

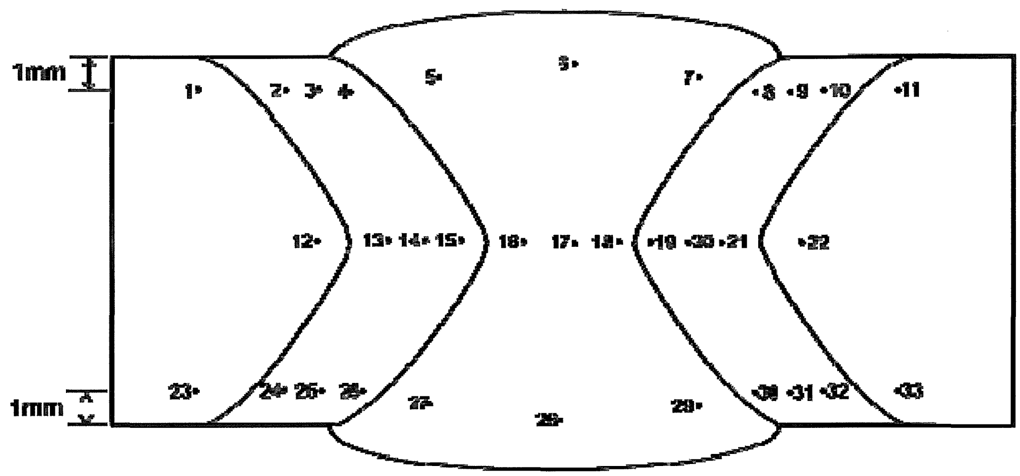

Figure 1: Schematic drawing showing the Vickers hardness indentation locations.

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Lab # 739108-16

RESULTS

Traverse Pass	Location	Indent	Section 1 Hardness (HV 10kgf)	Section 2 Hardness (HV 10kgf)
Top Cap Pass	Base Material	1	143	144
	HAZ	**2**	**158**	**162**
		3	**169**	**154**
		4	**171**	**158**
	Weld	5	183	181
		6	190	193
		7	180	188
	HAZ	**8**	**161**	**173**
		9	**156**	**160**
		10	**151**	**158**
	Base Material	11	144	146
Mid-Thickness Pass	Base Material	12	146	149
	HAZ	**13**	**149**	**166**
		14	**149**	**161**
		15	**160**	**160**
	Weld	16	169	171
		17	172	186
		18	173	181
	HAZ	**19**	**144**	**169**
		20	**144**	**143**
		21	**146**	**147**
	Base Material	22	139	139
Bottom Cap Pass	Base Material	23	150	151
	HAZ	**24**	**167**	**163**
		25	**163**	**154**
		26	**162**	**161**
	Weld	27	198	187
		28	198	198
		29	196	197
	HAZ	**30**	**154**	**160**
		31	**155**	**167**
		32	**161**	**167**
	Base Material	33	142	147

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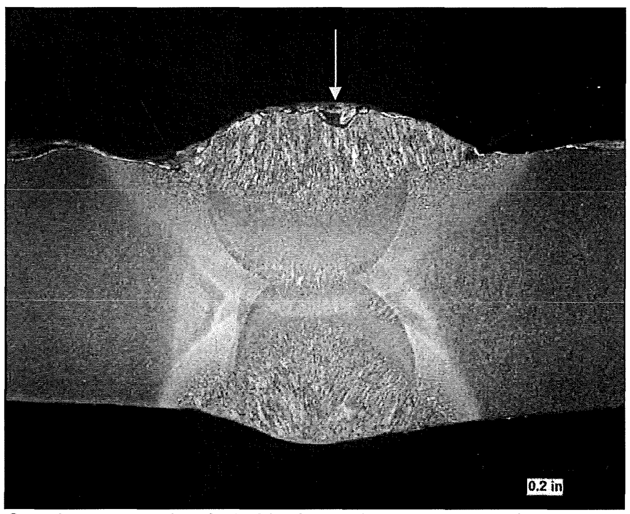

Specimen examined at 4X, photo shown at approximately 4X
Etched in 2% Nital

Figure 2: Photomacrograph of the Section 1, which had discontinuities at both toes (red arrows) and porosity (yellow arrow) on the face on one side of the weld.

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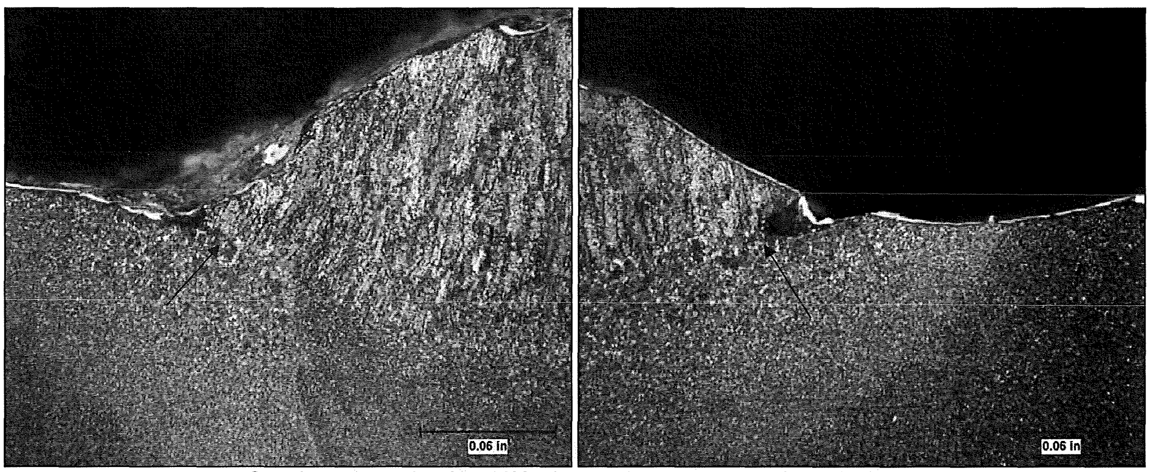

Specimen examined at 16X, photos shown at approximately 15X
Etched in 2% Nital

Figure 3: Photomacrographs of the Section 1. The discontinuities at the toes of the weld were revealed to be cracks propagating along the fusion line of the weld (red arrows).

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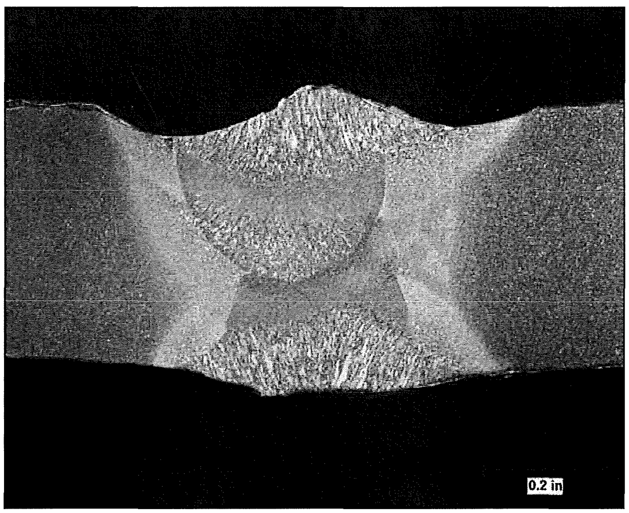

Specimen examined at 4X, photo shown at approximately 4X
Etched in 2% Nital

Figure 4: Photomacrograph of the Section 2, which had discontinuities at both toes (red arrows) on one side of the weld.

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Report For:	TEAM Industrial Services (NFLD) 41 Sagona Avenue MOUNT PEARL, Newfoundland A1N 4P9	**Laboratory #:** **Report Date:** **Received Date:**	**739108-16** October 27, 2016 October 17, 2016
Attention:	Keith Gowan	**Customer P.O.#:**	
Specimen:	For Hatch Limited, "Penstock" Weld Pipe Coupon		

MACROETCH EVALUATION TEST REPORT

Two random transverse sections were cut from the submitted weld coupon and prepared according to ASTM E3-11. The sections were arbitrarily labelled Section 1 and Section 2 by CMTL. The sections were etched in 2% Nital and then examined using a stereo microscope for general comments on weld imperfections.

RESULTS

Section 1: Examination of the specimen showed that the weld had discontinuities at both toes and porosity on the face on one side of the weld (refer to Figure 2). At higher magnification, the discontinuities at the toes of the weld were revealed to be cracks propagating along the fusion line of the weld (refer to Figure 3). The weld appeared to have no undercut or inclusions, and there was complete penetration and complete fusion observed throughout the weld.

Section 2: Examination of the specimen showed that the weld had discontinuities at both toes on one side of the weld (refer to Figure 4). At higher magnification, the discontinuities at the toes of the weld were revealed to be cracks propagating along the fusion line of the weld (refer to Figure 5). The weld appeared to have no porosity, undercut or inclusions, and there was complete penetration and complete fusion observed throughout the weld.

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Per Randi Lee
Randi Lee — *Quality Assurance*

Per Dan Bielby
Dan Bielby — *Technician*

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VICKERS HARDNESS TRAVERSE TEST REPORT

The macroetch sections were then re-polished according to ASTM E3-11 and subjected to a Vickers hardness traverse (refer to Figure 1). The Vickers hardness readings were performed according to ASTM E92-16 using a 10kgf test force. Indentations were measured at 100X magnification.

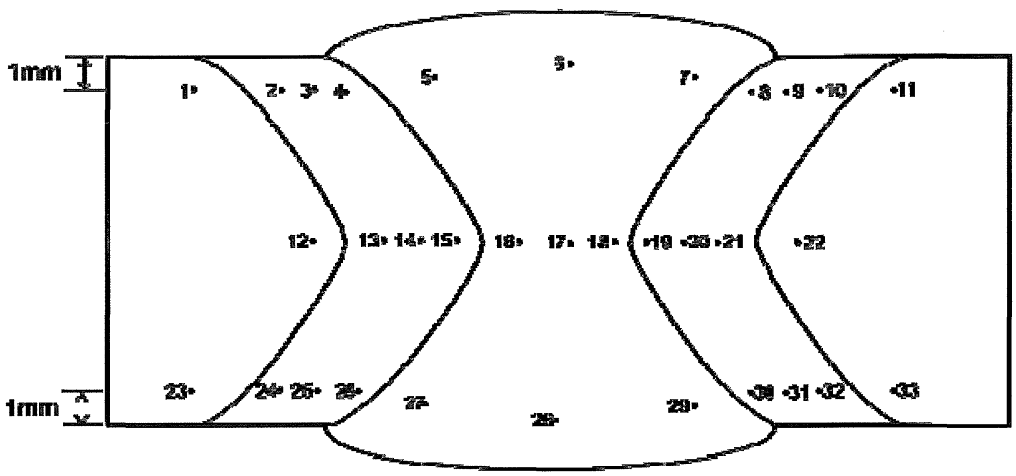

Figure 1: Schematic drawing showing the Vickers hardness indentation locations.

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Lab # 739108-16

RESULTS

Traverse Pass	Location	Indent	Section 1 Hardness (HV 10kgf)	Section 2 Hardness (HV 10kgf)
Top Cap Pass	Base Material	1	143	144
	HAZ	**2**	**158**	**162**
		3	**169**	**154**
		4	**171**	**158**
	Weld	5	183	181
		6	190	193
		7	180	188
	HAZ	**8**	**161**	**173**
		9	**156**	**160**
		10	**151**	**158**
	Base Material	11	144	146
Mid-Thickness Pass	Base Material	12	146	149
	HAZ	**13**	**149**	**166**
		14	**149**	**161**
		15	**160**	**160**
	Weld	16	169	171
		17	172	186
		18	173	181
	HAZ	**19**	**144**	**169**
		20	**144**	**143**
		21	**146**	**147**
	Base Material	22	139	139
Bottom Cap Pass	Base Material	23	150	151
	HAZ	**24**	**167**	**163**
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		26	**162**	**161**
	Weld	27	198	187
		28	198	198
		29	196	197
	HAZ	**30**	**154**	**160**
		31	**155**	**167**
		32	**161**	**167**
	Base Material	33	142	147

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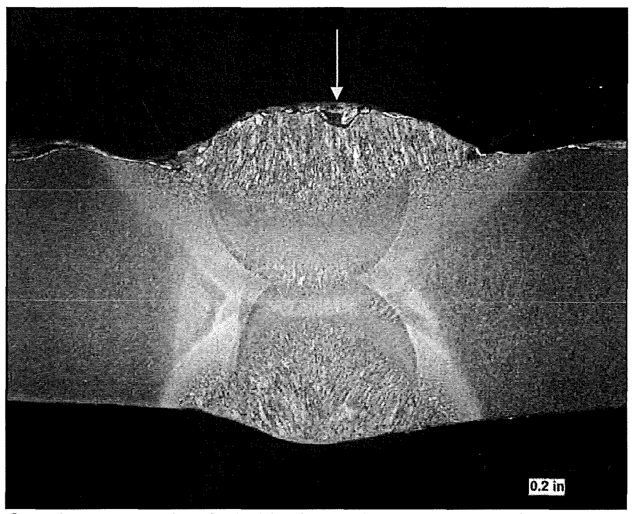

Specimen examined at 4X, photo shown at approximately 4X
Etched in 2% Nital

Figure 2: Photomacrograph of the Section 1, which had discontinuities at both toes (red arrows) and porosity (yellow arrow) on the face on one side of the weld.

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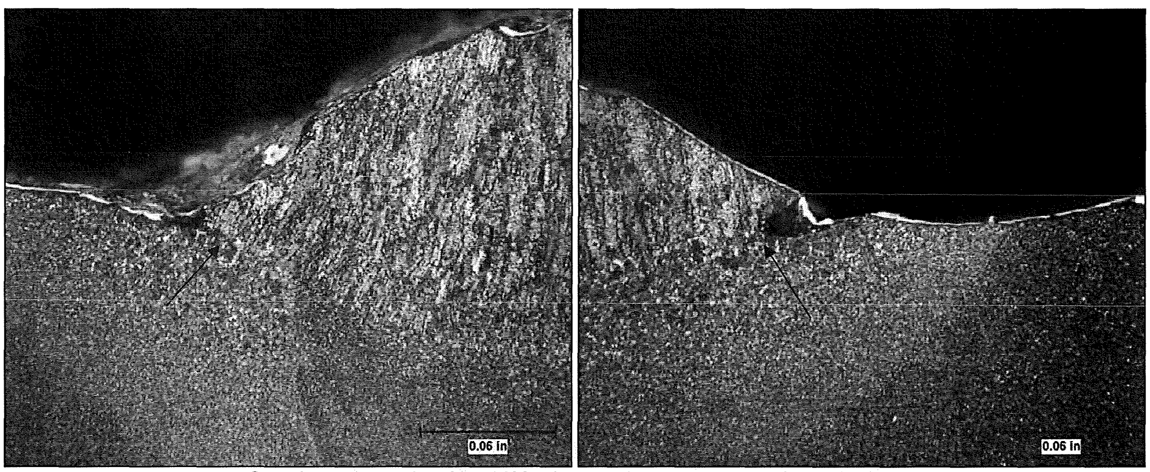

Specimen examined at 16X, photos shown at approximately 15X
Etched in 2% Nital

Figure 3: Photomacrographs of the Section 1. The discontinuities at the toes of the weld were revealed to be cracks propagating along the fusion line of the weld (red arrows).

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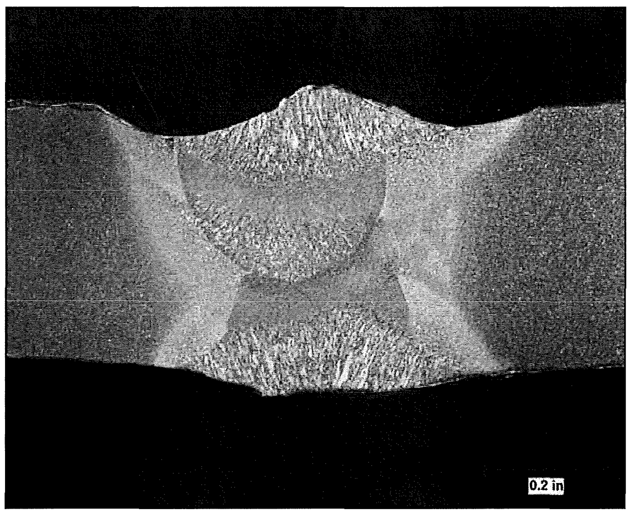

Specimen examined at 4X, photo shown at approximately 4X
Etched in 2% Nital

Figure 4: Photomacrograph of the Section 2, which had discontinuities at both toes (red arrows) on one side of the weld.

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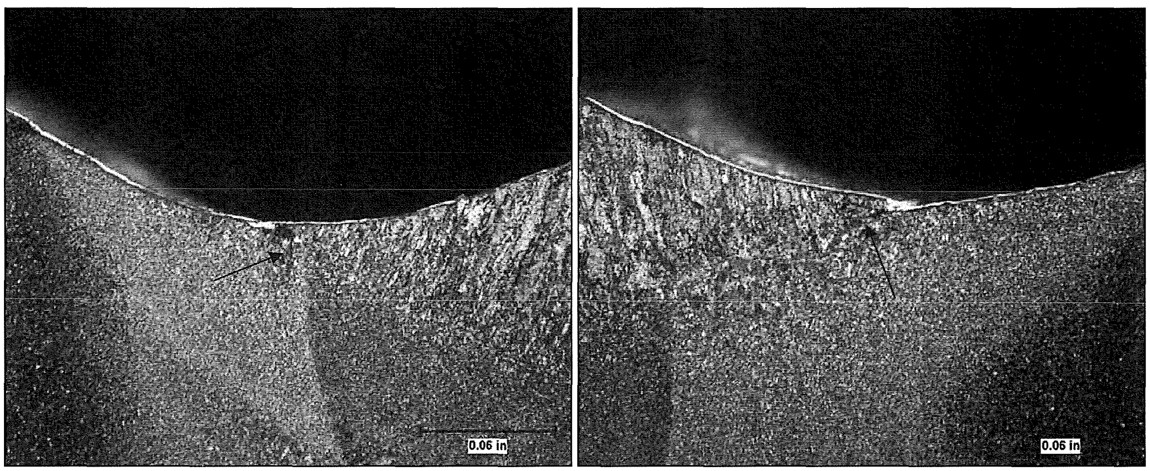

Specimen examined at 16X, photos shown at approximately 15X
Etched in 2% Nital

Figure 5: Photomacrographs of the Section 2. The discontinuities at the toes of the weld were revealed to be cracks propagating along the fusion line of the weld (red arrows).

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Report For:	TEAM Industrial Services (NFLD) 41 Sagona Avenue MOUNT PEARL, Newfoundland A1N 4P9	**Laboratory #:**	**742906-16 (Revised)**
		Report Date:	December 16, 2016
		Received Date:	December 6, 2016
Attention:	Keith Gowan	**Customer P.O.#:**	
Specimen:	For Hatch Limited, "Penstock" Weld Pipe Coupon		

METALLURGICAL TEST REPORT

Two weld coupon specimens, previously subjected to macroscopic examination (CMTL Lab #739108-16), were further sectioned, then mounted and prepared for microscopic examination in accordance with ASTM E3-11. The specimens were etched in 2% Nital and examined using an optical microscope. Examinations were performed at and near fusion line locations on either side of the weld, where the cracks were observed during the previous macroscopic examination. These locations were labelled as "FL" and "FL +1" as instructed by the customer.

RESULTS

Section 1: Examination of the weld coupon specimen at the "FL" locations revealed transgranular cracks propagating through the HAZ of the weld from cavities located at both toes on the face of the weld (refer to Figure 1). Both cavities were filled with corrosion product, indicating the cavities may have formed due to pitting corrosion. The HAZ microstructure at the toe of the weld consisted of relatively coarse-grained pearlite with intergranular ferrite. The weld microstructure consisted of columnar ferrite and pearlite. At the "FL +1" locations, the HAZ microstructure was a heterogeneous mixture of ferrite and pearlite, with a more refined grain size (refer to Figure 2).

Section 2: Examination of the weld coupon specimen at the "FL" locations revealed transgranular cracks propagating through the HAZ of the weld from a cavity located at one toe on the face of the weld, and from an overlap at the other toe on the face of the weld (refer to Figure 3). The cavity was filled with corrosion product, indicating it may have formed due to pitting corrosion. An inclusion was observed within the overlap. The HAZ microstructure at the toe of the weld consisted of relatively coarse-grained pearlite with intergranular ferrite. The weld microstructure consisted of columnar ferrite and pearlite. At the "FL +1" locations, the HAZ microstructure was a heterogeneous mixture of ferrite and pearlite, with a more refined grain size (refer to Figure 4).

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Per Randi Lee
Randi Lee *Quality Assurance*

Per Dan Bielby
Dan Bielby *Technician*

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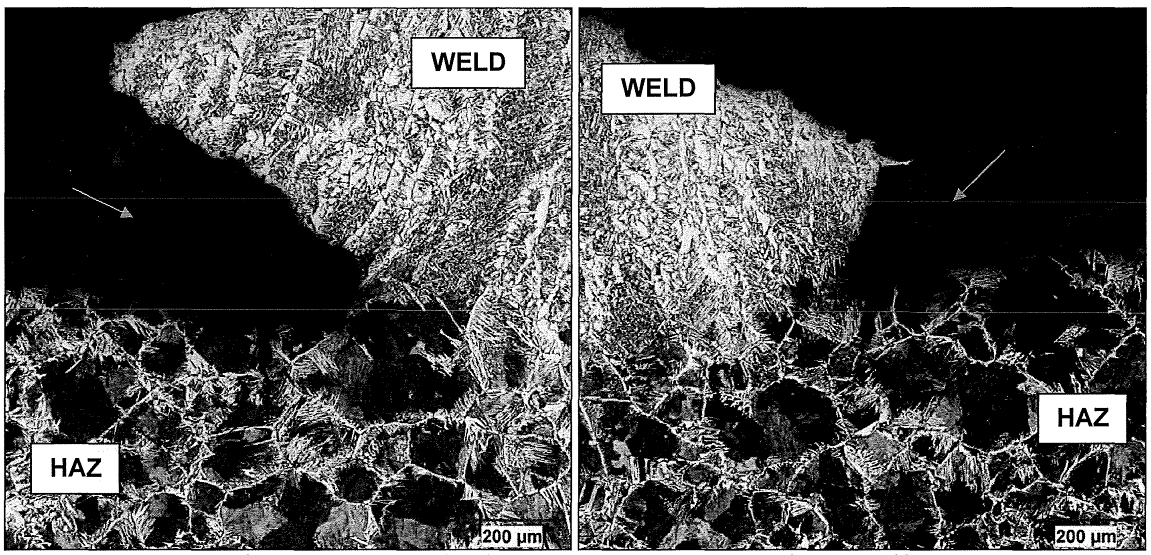
TEAM Industrial Services (NFLD)
Lab #742906-16 (Revised)



Specimen examined at 100X, photos shown at approximately 85X
Etched in 2% Nital

Figure 1: Photomicrographs of the Section 1 weld coupon at the "FL" locations. Transgranular cracks (red arrows) propagated through the HAZ of the weld from cavities located at the both toes on the face of the weld. Both cavities were filled with corrosion product (green arrows). The HAZ microstructure at the toe of the weld consisted of relatively coarse-grained pearlite with intergranular ferrite. The weld microstructure consisted of columnar ferrite and pearlite.

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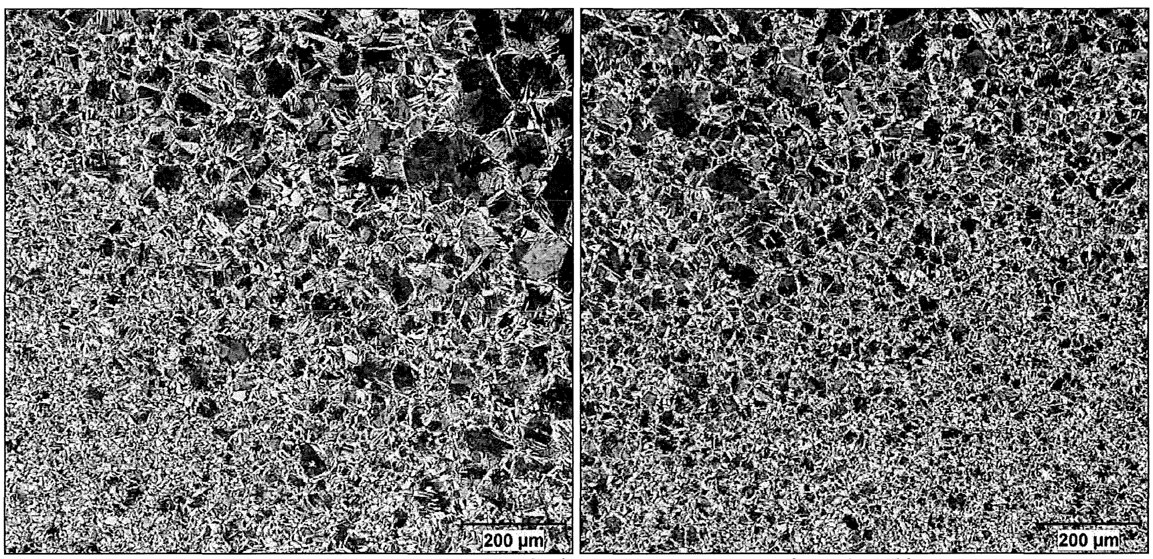

Specimen examined at 100X, photos shown at approximately 85X
Etched in 2% Nital

Figure 2: Photomicrographs of the Section 1 weld coupon at the “FL +1” locations, where the HAZ microstructure was a heterogeneous mixture of ferrite and pearlite, with a more refined grain size.

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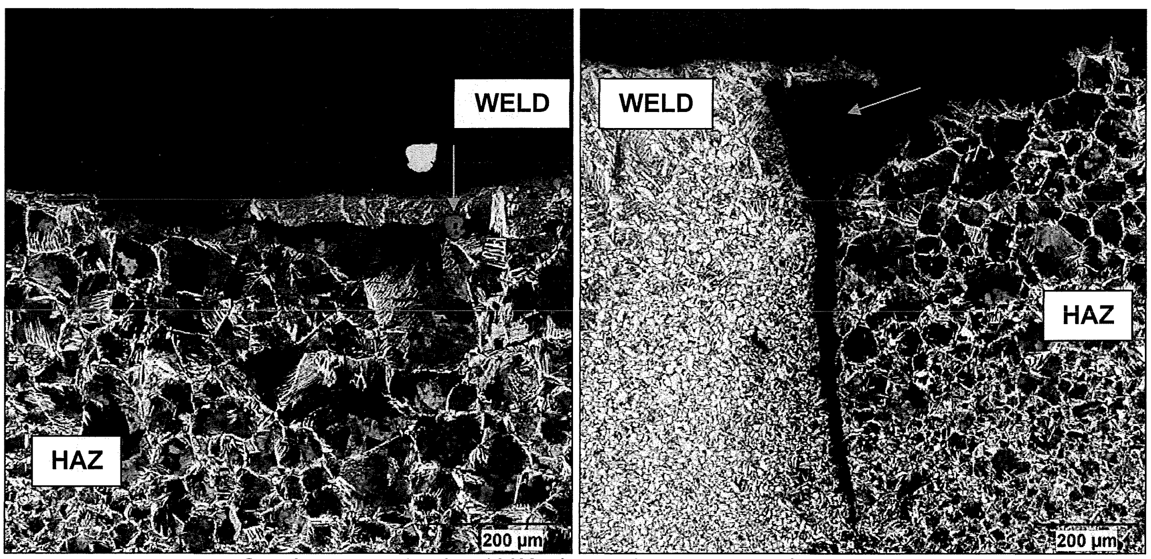
Lab #742906-16 (Revised)



Specimen examined at 100X, photos shown at approximately 85X
Etched in 2% Nital

Figure 3: Photomicrographs of the Section 2 weld coupon at the "FL" locations. Transgranular cracks (red arrows) propagated through the HAZ of the weld from a cavity located at one toe on the face of the weld (right), and from an overlap at the other toe on the face of the weld (left). The cavity was filled with corrosion product (green arrow, right). An inclusion was observed within the overlap (green arrow, left). The HAZ microstructure at the toe of the weld consisted of relatively coarse-grained pearlite with intergranular ferrite. The weld microstructure consisted of columnar ferrite and pearlite.

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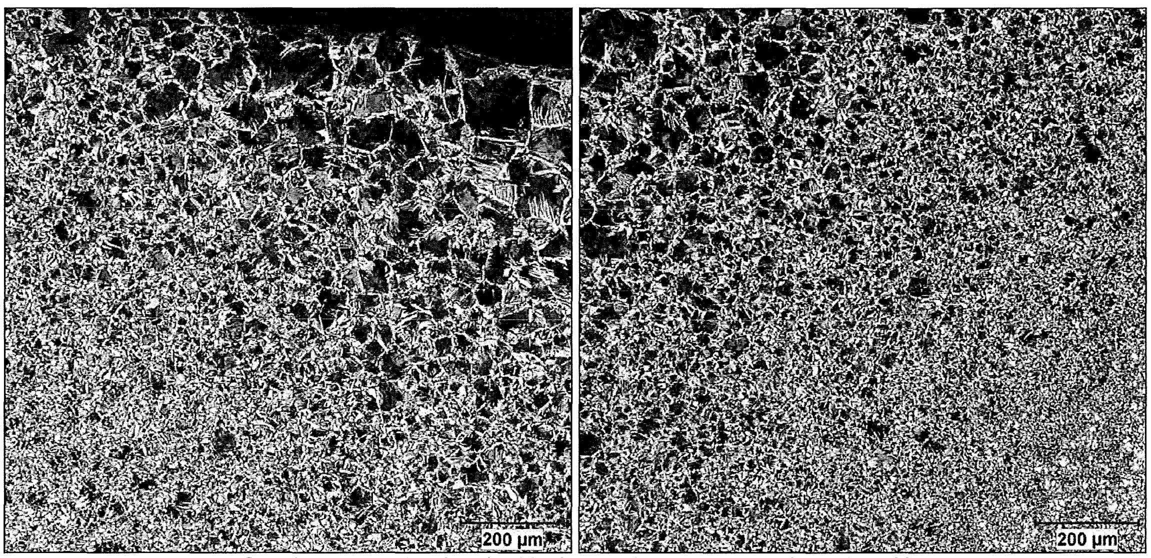

Specimen examined at 100X, photos shown at approximately 85X
Etched in 2% Nital

Figure 4: Photomicrographs of the Section 2 weld coupon at the "FL +1" locations, where the HAZ microstructure was a heterogeneous mixture of ferrite and pearlite, with a more refined grain size.

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Report for: TEAM Industrial Services (NFLD)
41 Sagona Avenue
MOUNT PEARL, Newfoundland
A1N 4P9

Laboratory No. 739111-16

Report Date: October 21, 2016
Received Date: October 17, 2016

Attention: Keith Gowan

Specimen: For Hatch Limited, "Penstock" Weld Pipe Coupon

TRANSVERSE WELD TENSILE REPORT

	RESULT	
Specimen Width:	0.745	in.
Specimen Thickness:	0.370	in.
Cross Sectional Area:	0.276	in^2
Maximum Load:	19,152	lbf
Ultimate Tensile Strength:	69,500	psi

The tensile specimen fractured in the base metal in a ductile manner.

Testing performed according to ASME Boiler and Pressure Vessel Code Section IX (2015 Edition).

Cambridge Materials Testing Limited

Per Randi Lee
Randi Lee *Quality Assurance*

Per Matthew Liska
Matthew Liska *Technician*

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Report for: TEAM Industrial Services (NFLD)
41 Sagona Avenue
MOUNT PEARL, Newfoundland
A1N 4P9

Laboratory No. 739110–16

Report Date: October 21, 2016
Received Date: October 17, 2016

Attention: Keith Gowan

Specimen: For Hatch Limited, "Penstock" Weld Pipe Coupon

CHEMICAL ANALYSIS TEST REPORT

Total Carbon	0.073	%	Silicon	0.52	%
Manganese	0.69	%	Titanium	0.02	%
Phosphorus	0.015	%	Vanadium	0.01	%
Sulphur	0.021	%			

Chemistry was performed on the weld metal.

Chemical analysis performed according to ASTM E1019-11, ASTM E1097-12 (modified) and ASTM E1479-99(2011).

Cambridge Materials Testing Limited

Per Randi Lee
Randi Lee *Quality Assurance*

Per Brittany DeGraaf
Brittany DeGraaf *Technician*

Cambridge materials testing limited

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Report for: TEAM Industrial Services (NFLD)
41 Sagona Avenue
MOUNT PEARL, Newfoundland
A1N 4P9

Laboratory No. 739109–16

Report Date: October 21, 2016
Received Date: October 17, 2016

Attention: Keith Gowan

Specimen: For Hatch Limited, "Penstock" Weld Pipe Coupon

CHEMICAL ANALYSIS TEST REPORT

Total Carbon	0.21	%
Manganese	0.52	%
Phosphorus	< 0.010	%
Sulphur	0.020	%
Silicon	0.07	%

The above analysis satisfies the chemical composition limits of UNS grade G10200 (1020) and G10230 (1023) steel.

Chemical analysis performed according to ASTM E1019-11, ASTM E1097-12 (modified) and ASTM E1479-99(2011).

Cambridge Materials Testing Limited

Per Randi Lee
Randi Lee — *Quality Assurance*

Per Brittany DeGraaf
Brittany DeGraaf — *Technician*

Cambridge
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Report For: TEAM Industrial Services (NFLD)
41 Sagona Avenue
MOUNT PEARL, Newfoundland
A1N 4P9

Laboratory #: **739812-16**

Report Date: October 26, 2016
Received Date: October 25, 2016

Attention: Keith Gowan

Customer P.O.#:

Specimen: For Hatch Limited, Paint (Coal Tar Epoxy) from ID Surface of a "Penstock" Weld Pipe Coupon

TEST REPORT

One pipe section with paint was received for identification and quantitation of asbestos, if present, along with the identification, where possible, of other materials. The paint was removed from the pipe and milled to a powder for purposes of analysis in accordance with EPA/600/R-93/116 (July 1993) using both stereomicroscope and polarized light microscopy. The paint sample was analyzed to evaluate the morphology, colour, refractive index, extinction, sign of elongation, birefringence, and dispersion staining colour characteristics of fibrous matter.

RESULTS

SAMPLE DESCRIPTION	% COMPOSITION (VISUAL AREA ESTIMATION)	
	Asbestos	Other
Homogenous, black, hard, flakey, non-friable	None	Matrix: 100%

Notes: 1. No fibrous matter was identified within the paint material.
2. Testing performed at the CMTL Mississauga location.

File Name

Cambridge Materials Testing Limited

Per Jill Cook *Jill Cook*
Quality Assurance

Per
Technician

Appendix B
Weld Coupon #2 Test Report

1. Introduction

As part of the Root Cause Analysis (RCA) investigation a coupon measuring approximately 460 mm x 460 mm (18" x 18") was removed from section XX (CSA 40.8 Gr B material, Coupon #2) of BDE Penstock #1. The coupon incorporated a portion of one of the circumferential weld seams.

2. Required Tests

The following non-destructive testing was performed by TEAM Industrial Services, St. John's, NL, to aid the RCA investigation:

- Radiographic Examination

The following destructive testing was performed by Cambridge Materials Testing Limited, Cambridge, Ontario, to aid the RCA investigation:

- Macroetch Evaluation
- Vickers Hardness Traverse
- Microetch Evaluation
- Transverse Weld Tensile
- Weld Metal Chemical Analysis Test
- Base Metal Chemical Analysis Test

3. Test Results

Radiographic Examination

The radiographic examination showed no rejectable defects. Porosity was detected, but was in the range of acceptable limits.

Macroetch Evaluation

A Photomacroetch of the weld was prepared from two different sections of the coupon etched in 2% Nital. A stereo microscope was then used to examine the samples for general comments on weld imperfections.

- Both sections showed the weld had pitting along the inside diameter surface within the HAZ (at the weld toes).
- No cracks or inclusions were exhibited in either of the sections.
- Both sections showed there was complete penetration and complete fusion was observed throughout the weld.

Vickers Hardness Traverse

Both macroetch sections were re-polished according to ASTM E3-11 and subjected to a Vickers Hardness Traverse. The Vickers Hardness readings were performed according to ASTM E92-16 using a 10kgf test force and indentations were measured at 100x magnification.

- Hardness values for the weld metal ranged from 170 to 214
- Hardness values for the HAZ ranged from 168 to 214
- Hardness values for the Base material ranged from 174 to 185

Hardness values are within the range of normal expected values for this type of material and E4918 (E7018) welding consumables.

Microstructural Examination

The two sections used in the previous Vickers hardness traverse were re-prepared according to ASTM E3-11 for microstructural examination. The specimens were etched in 2% Nital and examined using an optical microscope at various magnifications. The examination was performed at and near the fusion line on either side of the weld and labeled “FL” and “FL+1mm” as instructed by the customer.

- Microstructure examination showed ferrite and pearlite in both specimens.
- Both specimens displayed a relatively coarse grain HAZ on either side of the FL locations.
- Both specimens displayed a more refined structured HAZ consisting of fairly uniform mixture of pearlite and ferrite on the FL+1mm locations.
- Some sulphide inclusions were found dispersed throughout the material at higher magnification.

Transverse Weld Tensile

- Ultimate Tensile Strength (UTS) of weld metal = 84.5 ksi (582.6 MPa)

The tensile specimen fractured in the weld zone in a ductile manner. Even though this test failed in the weld metal, the UTS of the weld metal is significantly higher than the normal UTS of the base metal.

Weld Metal Chemical Analysis

The chemistry indicated on the attached report is consistent with an E4918 (E7018) electrode.

The sulphur content is below the maximum allowable of 0.035% (CSA W48, Table 1); however, according to Lincoln and Air Liquide specification sheets, the normal level of sulphur in the deposited weld metal for standard SMAW electrodes is 0.008% to 0.013% with

E4918 (E7018) normally around 0.011%. Thus, even though the sulphur content is below the maximum allowable at 0.018%, it is still above normal levels.

Total Carbon, Manganese, Phosphorus, Sulphur, and Silicon values are all within specifications.

Base Metal Chemical Analysis

The base metal chemistry is consistent with CSA 40.8 Gr B material.

Total Carbon, Manganese, Phosphorus, Sulphur, and Silicon values are all within composition specifications for UNS grade G15240 (1524) steel.

Attachment A
Test Results

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Report for: TEAM Industrial Services (NFLD)
41 Sagona Avenue
MOUNT PEARL, Newfoundland
A1N 4P9

Laboratory No. 744803–17

Report Date: January 13, 2017
Received Date: January 09, 2017

Attention: Cyril Pretty

Specimen: For Hatch Limited, "Penstock" Weld Pipe Coupon, Sample #2 - Circumferential Weld, Material: CSA 40.8 Gr. B

CHEMICAL ANALYSIS TEST REPORT

Total Carbon	0.21	%
Manganese	1.44	%
Phosphorus	0.010	%
Sulphur	0.020	%
Silicon	0.26	%

Chemistry was performed on the base metal.

The above analysis satisfies the chemical composition limits of UNS grade G15240 (1524) steel.

Chemical analysis performed according to ASTM E1019-11, ASTM E1097-12 (modified) and ASTM E1479-99(2011).

Cambridge Materials Testing Limited

Per Randi Lee
Randi Lee — *Quality Assurance*

Per Brittany DeGraaf
Brittany DeGraaf — *Technician*

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Report for: TEAM Industrial Services (NFLD)
41 Sagona Avenue
MOUNT PEARL, Newfoundland
A1N 4P9

Laboratory No. 744805-17

Report Date: January 13, 2017
Received Date: January 09, 2017

Attention: Cyril Pretty

Specimen: For Hatch Limited, "Penstock" Weld Pipe Coupon, Sample #2 - Circumferential Weld, Material: CSA 40.8 Gr. B

TRANSVERSE WELD TENSILE REPORT

	RESULT	
Specimen Width:	0.748	in.
Specimen Thickness:	0.345	in.
Cross Sectional Area:	0.258	in^2
Maximum Load:	21,842	lbf
Ultimate Tensile Strength:	84,500	psi

The tensile specimen fractured in the weld zone in a ductile manner.

Testing performed according to ASME Boiler and Pressure Vessel Code Section IX (2015 Edition).

Cambridge Materials Testing Limited

Per Randi Lee
Randi Lee — *Quality Assurance*

Per Matthew Liska
Matthew Liska — *Technician*

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Report for: TEAM Industrial Services (NFLD)
41 Sagona Avenue
MOUNT PEARL, Newfoundland
A1N 4P9

Laboratory No. 744804–17

Report Date: January 13, 2017
Received Date: January 09, 2017

Attention: Cyril Pretty

Specimen: For Hatch Limited, "Penstock" Weld Pipe Coupon, Sample #2 - Circumferential Weld, Material: CSA 40.8 Gr. B

CHEMICAL ANALYSIS TEST REPORT

Total Carbon	0.14	%
Manganese	1.60	%
Phosphorus	0.015	%
Sulphur	0.018	%
Silicon	0.39	%

Chemistry was performed on the weld metal.

Chemical analysis performed according to ASTM E1019-11, ASTM E1097-12 (modified) and ASTM E1479-99(2011).

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Report For:	TEAM Industrial Services (NFLD) 41 Sagona Avenue MOUNT PEARL, Newfoundland A1N 4P9	**Laboratory #:** **Report Date:** **Received Date:**	**744802-17** January 13, 2017 January 9, 2017
Attention:	Cyril Pretty	**Customer P.O.#:**	
Specimen:	For Hatch Limited, "Penstock" Weld Pipe Coupon, Sample #2 Circumferential Weld Material: CSA 40.8 Gr. B		

METALLURGICAL TEST REPORT

Two random transverse sections were cut from the submitted weld coupon and prepared according to ASTM E3-11. The sections were arbitrarily labelled Section 1 and Section 2 by CMTL and subjected to a macroetch evaluation, microstructural examination and Vickers hardness traverse.

MACROETCH EVALUATION

The sections were etched in 2% Nital and then examined using a stereo microscope for general comments on weld imperfections.

RESULTS

Section 1: Examination of the specimen showed that the weld had pitting along the inside diameter surface within the HAZ (at the weld toes) (refer to Figure 2). The weld appeared to have no cracks or inclusions, and there was complete penetration and complete fusion observed throughout the weld.

Section 2: Examination of the specimen showed that the weld had pitting along the inside diameter surface within the HAZ (at the weld toes) (refer to Figure 3). The weld appeared to have no cracks or inclusions, and there was complete penetration and complete fusion observed throughout the weld.

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Per Randi Lee
Randi Lee *Quality Assurance*

Per Holly Steele
Holly Steele *Technician*

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Lab # 744802-17

VICKERS HARDNESS TRAVERSE

The macroetch sections were then re-polished according to ASTM E3-11 and subjected to a Vickers hardness traverse (refer to Figure 1). The Vickers hardness readings were performed according to ASTM E92-16 using a 10kgf test force. Indentations were measured at 100X magnification.

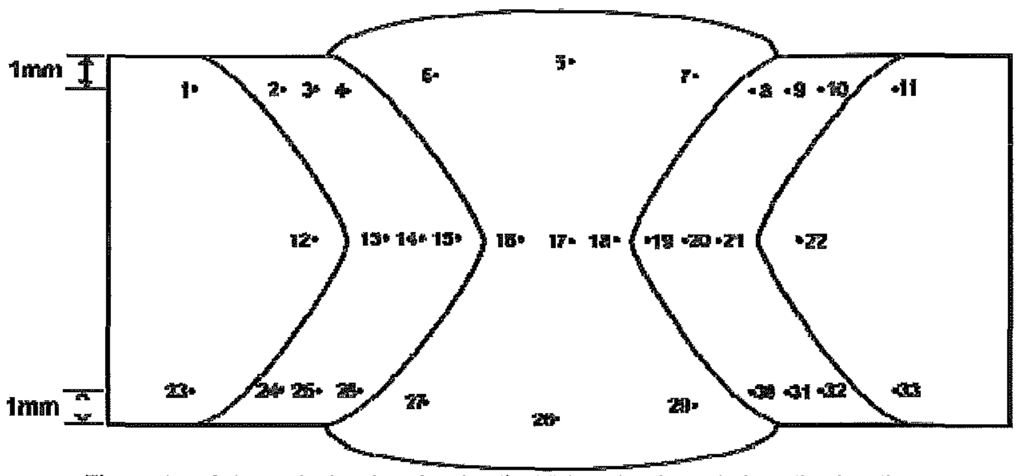

Figure 1: Schematic drawing showing the Vickers hardness indentation locations.

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RESULTS

Traverse Pass	Location	Indent	Section 1 Hardness (HV 10kgf)	Section 2 Hardness (HV 10kgf)
Top Cap Pass	Base Material	1	181	181
	HAZ	**2**	**171**	**168**
		3	**181**	**180**
		4	**184**	**193**
	Weld	5	170	176
		6	173	177
		7	178	175
	HAZ	**8**	**185**	**188**
		9	**183**	**190**
		10	**182**	**176**
	Base Material	11	185	183
Mid-Thickness Pass	Base Material	12	179	185
	HAZ	**13**	**184**	**193**
		14	**192**	**197**
		15	**203**	**212**
	Weld	16	188	197
		17	199	196
		18	195	199
	HAZ	**19**	**209**	**207**
		20	**201**	**196**
		21	**190**	**195**
	Base Material	22	184	184
Bottom Cap Pass	Base Material	23	174	176
	HAZ	**24**	**185**	**187**
		25	**196**	**194**
		26	**214**	**209**
	Weld	27	214	192
		28	198	197
		29	207	195
	HAZ	**30**	**214**	**210**
		31	**209**	**198**
		32	**193**	**188**
	Base Material	33	178	177

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MICROSTRUCTURAL EXAMINATION

The sections used for the Vickers hardness traverse were re-prepared according to ASTM E3-11 for microstructural examination. The specimens were etched in 2% Nital and examined using an optical microscope at various magnifications. Examinations were performed at and near the fusion line on either side of the weld, the weld was arbitrarily labelled "Side A" and "Side B" by CMTL for identification purposes. These locations were labelled as "FL" and "FL+1mm" as instructed by the customer.

RESULTS

Section 1: Examination of the etched specimen revealed a microstructure consisting of ferrite and pearlite. A relatively coarse grain HAZ was observed on either side of the weld at the "FL" locations (refer to Figure 4 and Figure 5). At the "FL+1mm" locations, the HAZ showed a more refined structure consisting of a fairly uniform mixture of ferrite and pearlite. At a higher magnification some sulphide inclusions were observed dispersed throughout the material (refer to Figure 6).

Section 2: Examination of the etched specimen revealed a microstructure consisting of ferrite and pearlite. A relatively coarse grain HAZ was observed on either side of the weld at the "FL" locations (refer to Figure 7 and Figure 8). At the "FL+1mm" locations, the HAZ showed a more refined structure consisting of a fairly uniform mixture of ferrite and pearlite. At a higher magnification some sulphide inclusions were observed dispersed throughout the material (refer to Figure 9).

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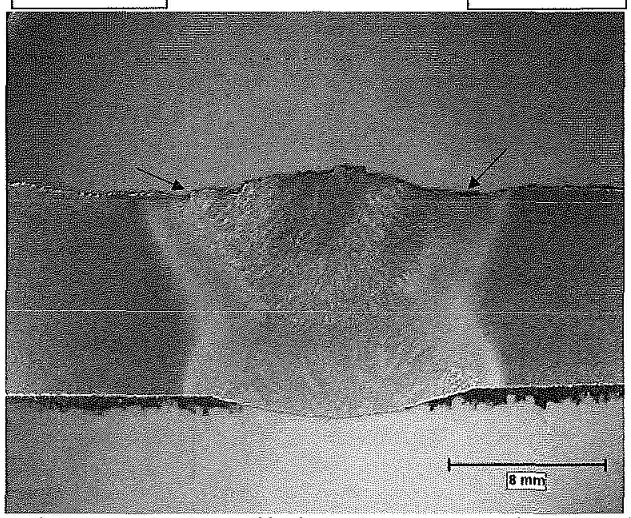
Side A

Side B



Specimen examined at 3.2X, photo shown at approximately 3.2X
Etched in 2% Nital

Figure 2: Photomacrograph of the Section 1, showing the pitting along the surface within the HAZ/at the weld toes along the inside diameter.

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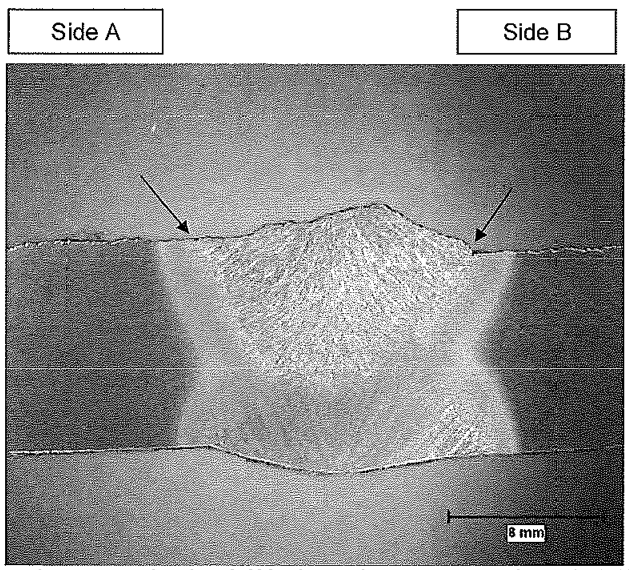

Specimen examined at 3.2X, photo shown at approximately 3.2X
Etched in 2% Nital

Figure 3: Photomacrograph of the Section 2, showing the pitting along the surface within the HAZ/at the weld toes along the inside diameter.

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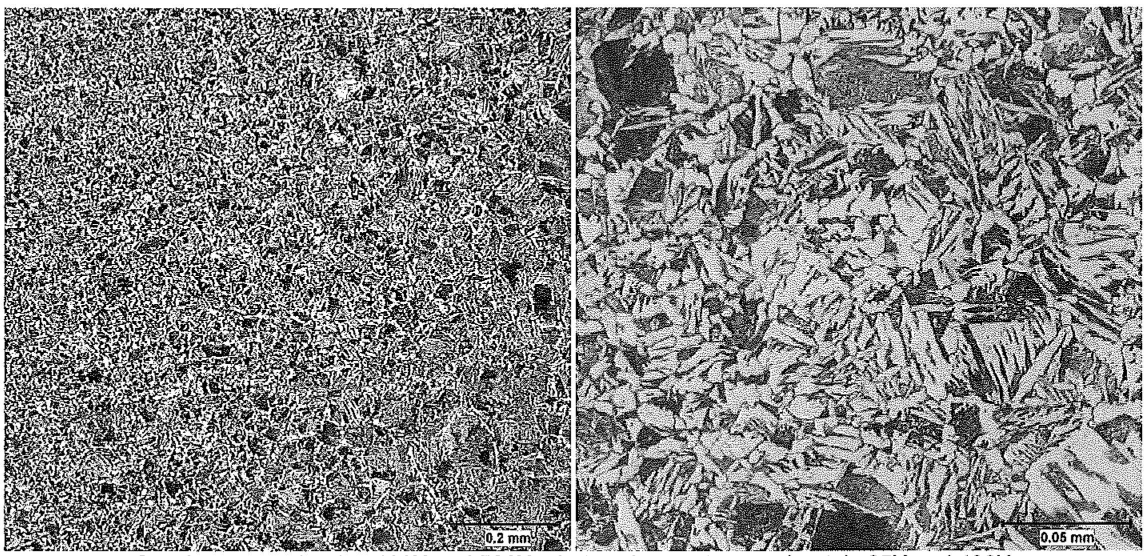

Specimen examined at 100X and 500X, photos shown at approximately 85X and 428X
Etched in 2% Nital

Figure 4: Photomicrographs of the Section 1 "Side A" weld coupon at the "FL" location, where a relatively coarse grain HAZ of ferrite and pearlite was observed.

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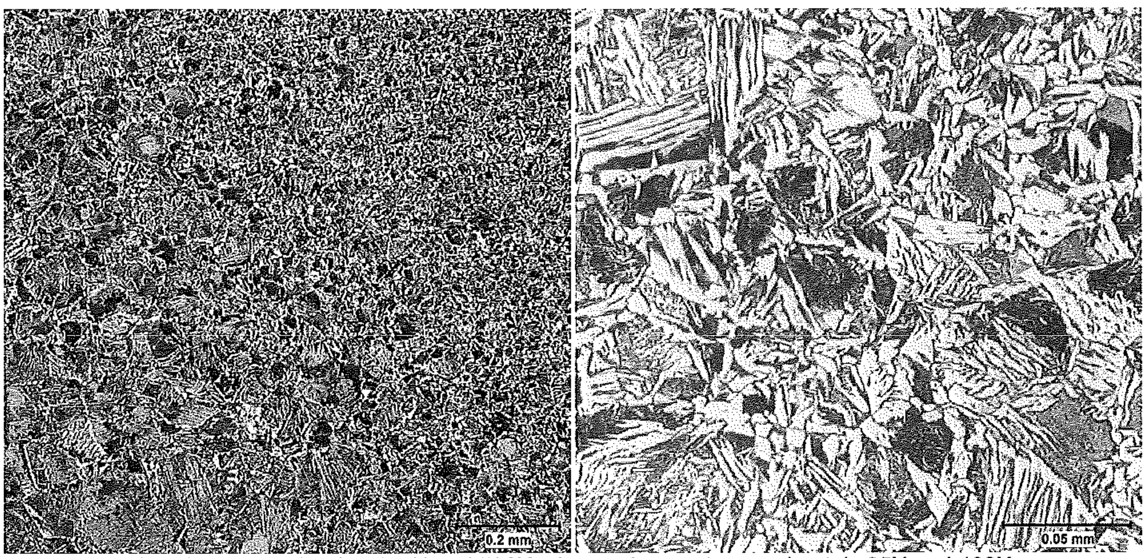

Specimen examined at 100X and 500X, photos shown at approximately 85X and 428X
Etched in 2% Nital

Figure 5: Photomicrographs of the Section 1 "Side B" weld coupon at the "FL" location, where a relatively coarse grain HAZ of ferrite and pearlite was observed.

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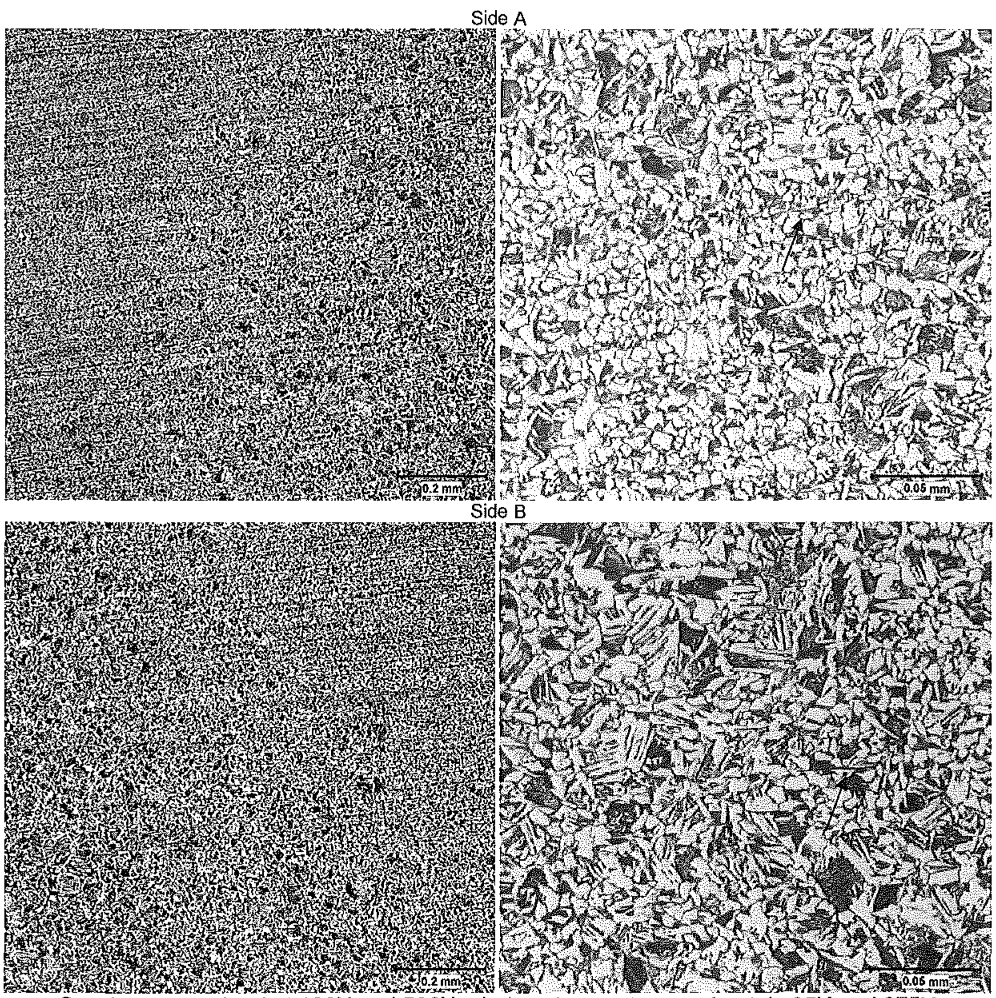

Specimen examined at 100X and 500X, photos shown at approximately 85X and 375X
Etched in 2% Nital

Figure 6: Photomicrographs of the Section 1 "Side A" and "Side B" weld coupon at the "FL +1" locations; where the HAZ microstructure showed a fairly uniform mixture of ferrite and pearlite, with a more refined grain size. At a higher magnification some sulphide inclusions were observed (refer to red arrows).

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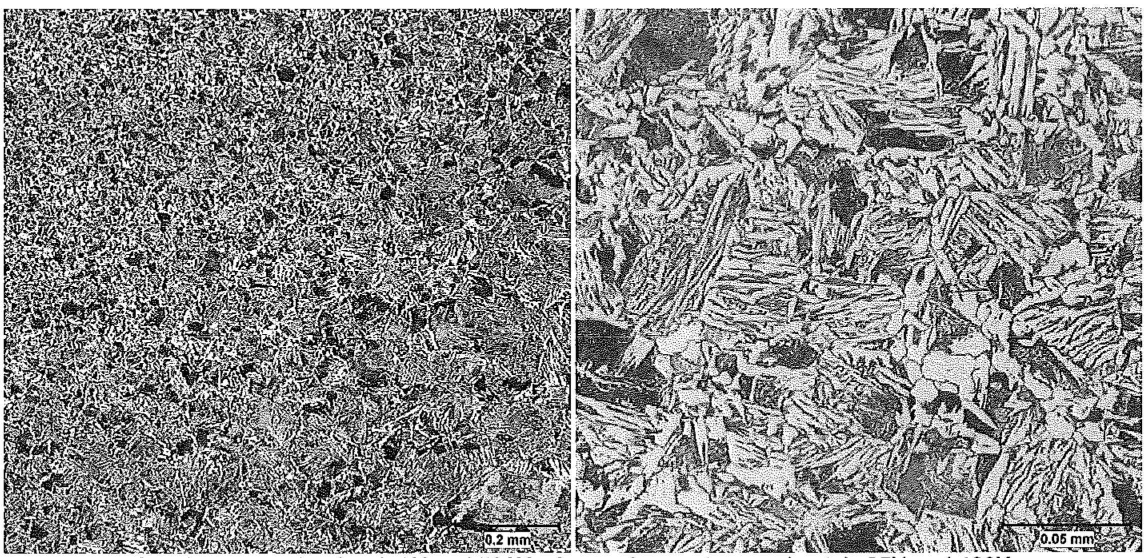

Specimen examined at 100X and 500X, photos shown at approximately 85X and 428X
Etched in 2% Nital

Figure 7: Photomicrographs of the Section 2 “Side A” weld coupon at the “FL” location, where a relatively coarse grain HAZ of ferrite and pearlite was observed.

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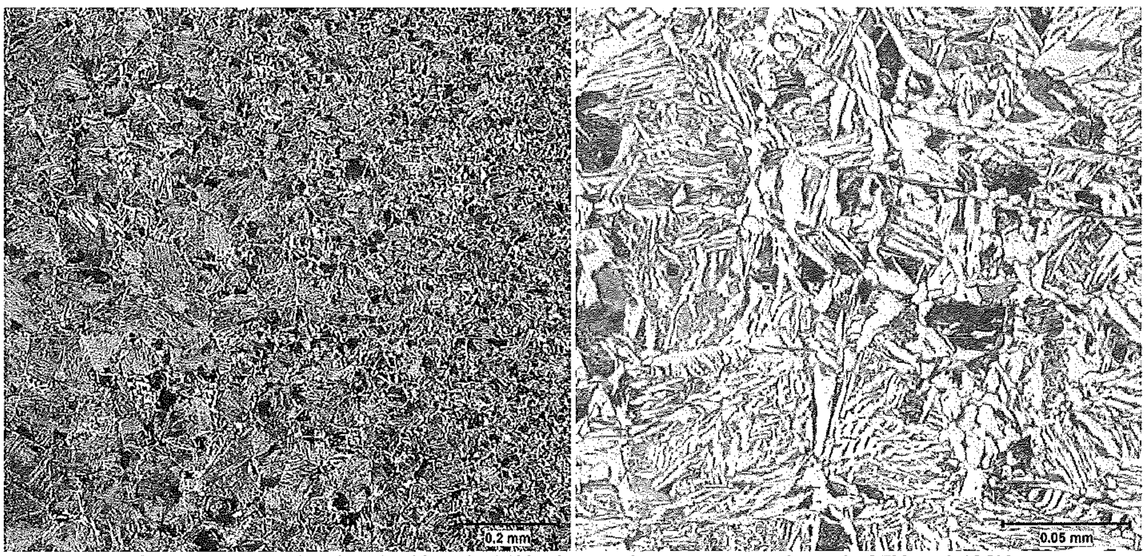

Specimen examined at 100X and 500X, photos shown at approximately 85X and 428X
Etched in 2% Nital

Figure 8: Photomicrographs of the Section 2 "Side B" weld coupon at the "FL" location, where a relatively coarse grain HAZ of ferrite and pearlite was observed.

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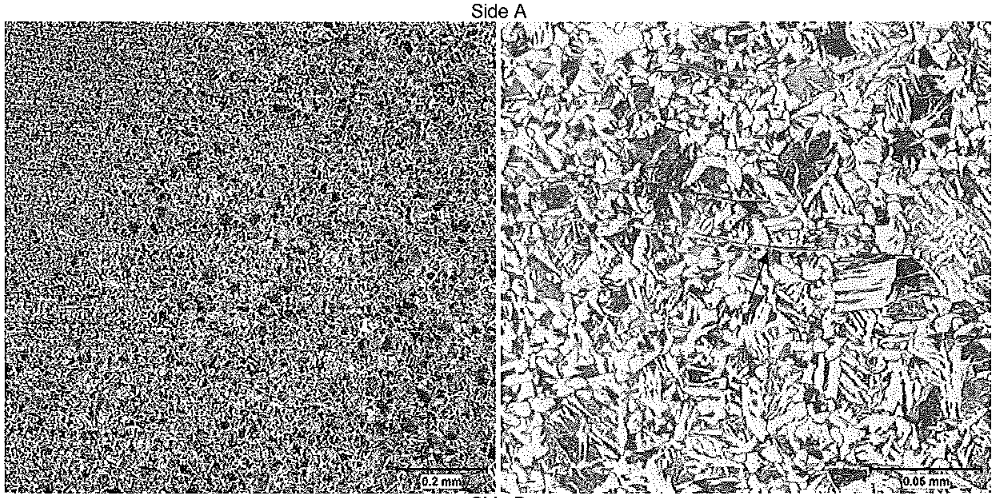
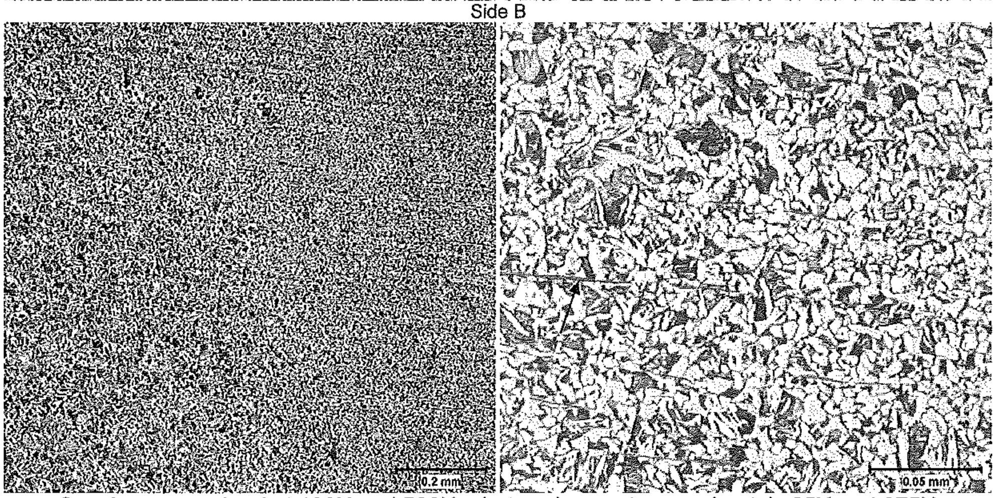
Side A



Side B



Specimen examined at 100X and 500X, photos shown at approximately 85X and 375X
Etched in 2% Nital

Figure 9: Photomicrographs of the Section 2 "Side A" and "Side B" weld coupon at the "FL +1" locations; where the HAZ microstructure showed a fairly uniform mixture of ferrite and pearlite, with a more refined grain size. At a higher magnification some sulphide inclusions were observed (refer to red arrows).

Appendix C
Weld Coupon #3 Test Report

1. Introduction

As part of the Root Cause Analysis (RCA) investigation a coupon measuring approximately 460 mm x 460 mm (18” x 18”) was removed from section XX (A285 Gr C section, Coupon #3) of BDE Penstock #1. The coupon incorporated a portion of one of the circumferential weld seams.

2. Required Tests

The following non-destructive testing was performed by TEAM Industrial Services, St. John’s, NL, to aid the RCA investigation:

- Radiographic Examination

The following destructive testing was performed by Cambridge Materials Testing Limited, Cambridge, Ontario, to aid the RCA investigation:

- Macroetch Evaluation
- Vickers Hardness Traverse
- Microetch Evaluation
- Transverse Weld Tensile
- Weld Metal Chemical Analysis Test
- Base Metal Chemical Analysis Test

3. Test Results

Radiographic Examination

The radiographic examination showed no rejectable defects.

Macroetch Evaluation

A Photomacroetch of the weld was prepared from two different sections of the coupon etched in 2% Nital. A stereo microscope was then used to examine the samples for general comments on weld imperfections.

- Both sections showed the weld had pitting along the inside diameter surface within the HAZ (at the weld toes).
- No cracks or inclusions were exhibited in either of the sections.
- Both sections showed there was complete penetration and complete fusion was observed throughout the weld.

Microstructural Examination

A Photomacroetch of the weld was prepared from two different sections of the coupon etched in 2% Nital. A stereo microscope was then used to examine the samples for general comments on weld imperfections.

- Microstructure examination showed ferrite and pearlite in both specimens.
- Both specimens displayed a relatively coarse grain HAZ on either side of the FL locations.
- Both specimens displayed a more refined structured HAZ consisting of fairly uniform mixture of pearlite and ferrite on the FL+1mm locations.
- Some sulphide inclusions were found dispersed throughout the material at higher magnification.

Vickers Hardness Traverse

Both macroetch sections were re-polished according to ASTM E3-11 and subjected to a Vickers Hardness Traverse. The Vickers Hardness readings were performed according to ASTM E92-16 using a 10kgf test force and indentations were measured at 100x magnification.

- Hardness values for the weld metal ranged from 153 to 181
- Hardness values for the HAZ ranged from 121 to 158
- Hardness values for the Base material ranged from 130 to 158

Hardness values are within the range of normal expected values for this type of material and E4918 (E7018) welding consumables.

Microstructural Examination

The two sections used in the previous Vickers hardness traverse were re-prepared according to ASTM E3-11 for microstructural examination. The specimens were etched in 2% Nital and examined using an optical microscope at various magnifications. The examination was performed at and near the fusion line on either side of the weld, arbitrarily named “Side A” and ”Side B” for CMTL identification purposes. These locations were labeled “FL” and “FL+1mm” as instructed by the customer.

- Microstructure examination showed ferrite and pearlite in both specimens.
- Both specimens displayed a relatively coarse grain HAZ on either side of the FL locations; with “Side A” having more ferrite observed and “Side B” having more pearlite with a more distinct coarse grain HAZ.
- Both specimens displayed a more refined structured HAZ consisting of fairly uniform mixture of pearlite and ferrite on the FL+1mm locations.

- Some sulphide inclusions were found dispersed throughout the material at higher magnification.

Transverse Weld Tensile

- Ultimate Tensile Strength (UTS) of weld metal = 63.5 ksi (437.8 MPa)
- The tensile specimen fractured in the weld zone in a ductile manner. Even though this test failed in the weld metal, the UTS of the weld metal is significantly higher than the normal UTS of the base metal.

Weld Metal Chemical Analysis

The chemistry indicated on the attached report is consistent with an E4918 (E7018) electrode.

The sulphur content is below the maximum allowable of 0.035% (CSA W48, Table 1); however, according to Lincoln and Air Liquide specification sheets, the normal level of sulphur in the deposited weld metal for standard SMAW electrodes is 0.008% to 0.013% with E4918 (E7018) normally around 0.011%. Thus, even though the sulphur content is below the maximum allowable at 0.023%, it is still above normal levels.

Total Carbon, Manganese, Phosphorus, Sulphur, and Silicon values are all within specifications.

Base Metal Chemical Analysis

Chemical Analysis is similar to the chemical composition limits of ASTM A285 Grade C steel, with the exception of Sulphur.

Attachment A
Test Results

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Report For:	TEAM Industrial Services (NFLD) 41 Sagona Avenue MOUNT PEARL, Newfoundland A1N 4P9	**Laboratory #:** **Report Date:** **Received Date:**	**743344-16 (Revised)** January 4, 2017 December 12, 2016
Attention:	Cyril Pretty	**Customer P.O.#:**	
Specimen:	For Hatch Limited, "Penstock" Weld Pipe Coupon, Sample #3 Circumferential Seam Material: ASTM A285 Gr. C		

METALLURGICAL TEST REPORT

Two random transverse sections were cut from the submitted weld coupon and prepared according to ASTM E3-11. The sections were arbitrarily labelled Section 1 and Section 2 by CMTL and subjected to a macroetch evaluation, microstructural examination and Vickers hardness traverse.

MACROETCH EVALUATION

The sections were etched in 2% Nital and then examined using a stereo microscope for general comments on weld imperfections.

RESULTS

Section 1: Examination of the specimen showed that the weld had pitting along the surface within the HAZ (at the weld toes) (refer to Figure 2). The weld appeared to have no cracks or inclusions, and there was complete penetration and complete fusion observed throughout the weld.

Section 2: Examination of the specimen showed that the weld had pitting along the surface within the HAZ (at the weld toes) (refer to Figure 3). The weld appeared to have no cracks or inclusions, and there was complete penetration and complete fusion observed throughout the weld.

Cambridge Materials Testing Limited

Per Randi Lee
Randi Lee *Quality Assurance*

Per Holly Steele
Holly Steele *Technician*

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VICKERS HARDNESS TRAVERSE

The macroetch sections were then re-polished according to ASTM E3-11 and subjected to a Vickers hardness traverse (refer to Figure 1). The Vickers hardness readings were performed according to ASTM E92-16 using a 10kgf test force. Indentations were measured at 100X magnification.

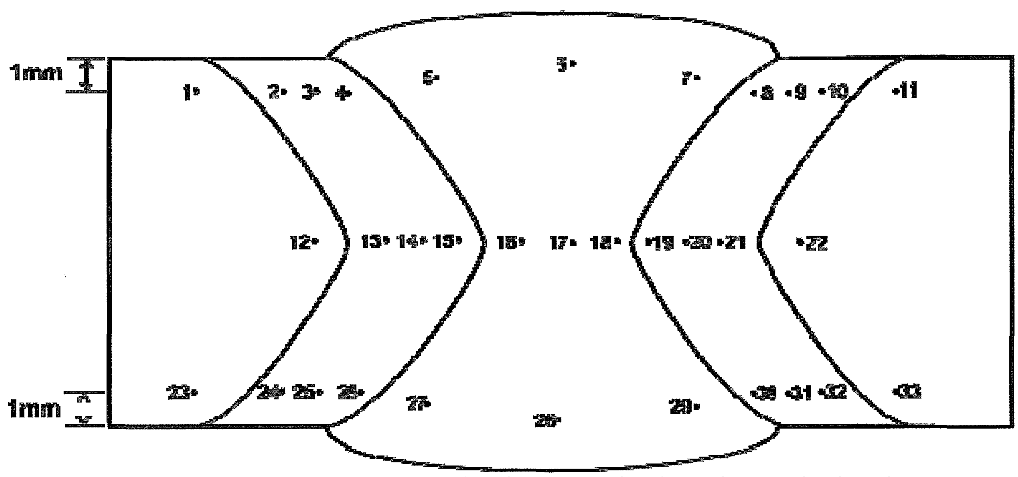

Figure 1: Schematic drawing showing the Vickers hardness indentation locations.

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RESULTS

Traverse Pass	Location	Indent	Section 1 Hardness (HV 10kgf)	Section 2 Hardness (HV 10kgf)
Top Cap Pass	Base Material	1	136	158
	HAZ	**2**	**133**	**155**
		3	**140**	**156**
		4	**136**	**158**
	Weld	5	164	161
		6	156	163
		7	166	180
	HAZ	**8**	**136**	**138**
		9	**138**	**136**
		10	**129**	**126**
	Base Material	11	134	141
Mid-Thickness Pass	Base Material	12	134	138
	HAZ	**13**	**133**	**147**
		14	**138**	**141**
		15	**139**	**142**
	Weld	16	154	153
		17	164	157
		18	161	160
	HAZ	**19**	**137**	**140**
		20	**137**	**138**
		21	**137**	**133**
	Base Material	22	134	131
Bottom Cap Pass	Base Material	23	133	138
	HAZ	**24**	**132**	**126**
		25	**135**	**139**
		26	**139**	**141**
	Weld	27	174	175
		28	181	174
		29	170	171
	HAZ	**30**	**143**	**141**
		31	**140**	**141**
		32	**121**	**143**
	Base Material	33	130	147

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MICROSTRUCTURAL EXAMINATION

The sections used for the Vickers hardness traverse were re-prepared according to ASTM E3-11 for microstructural examination. The specimens were etched in 2% Nital and examined using an optical microscope at various magnifications. Examinations were performed at and near the fusion line on either side of the weld, the weld was arbitrarily labelled “Side A” and “Side B” by CMTL for identification purposes. These locations were labelled as “FL” and “FL+1mm” as instructed by the customer.

RESULTS

Section 1: Examination of the etched specimen revealed a microstructure consisting of ferrite and pearlite. A relatively coarse grain HAZ was observed on either side of the weld at the “FL” locations; with Side A having more ferrite observed and Side B having more pearlite with a more distinct coarse grain HAZ (refer to Figure 4 and Figure 5). At the “FL+1mm” locations, the HAZ showed a more refined structure consisting of a fairly uniform mixture of ferrite and pearlite. At a higher magnification some sulphide inclusions were observed dispersed throughout the material (refer to Figure 6).

Section 2: Examination of the etched specimen revealed a microstructure consisting of ferrite and pearlite. A relatively coarse grain HAZ was observed on either side of the weld at the “FL” locations; with Side A having more ferrite observed and Side B having more pearlite with a more distinct coarse grain HAZ (refer to Figure 7 and Figure 8). At the “FL+1mm” locations, the HAZ showed a more refined structure consisting of a fairly uniform mixture of ferrite and pearlite. At a higher magnification some sulphide inclusions were observed dispersed throughout the material (refer to Figure 9).

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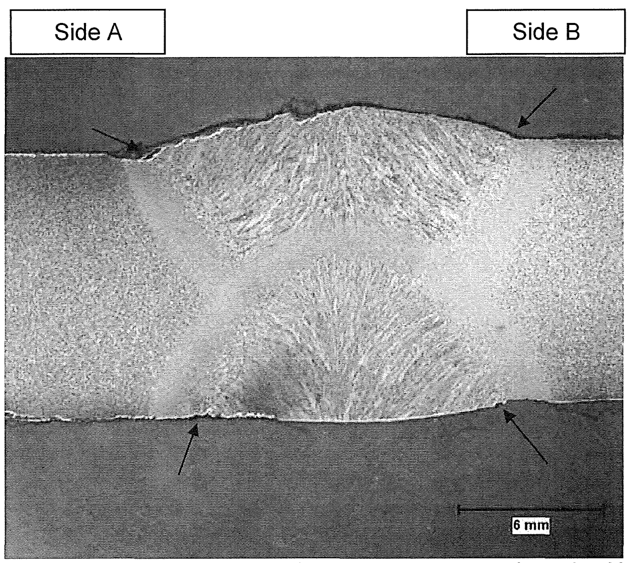
TEAM Industrial Services (NFLD)
Lab # 743344-16 (Revised)



Specimen examined at 4X, photo shown at approximately 4X
Etched in 2% Nital

Figure 2: Photomacrograph of the Section 1, showing the pitting along the surface within the HAZ/at the weld toes.

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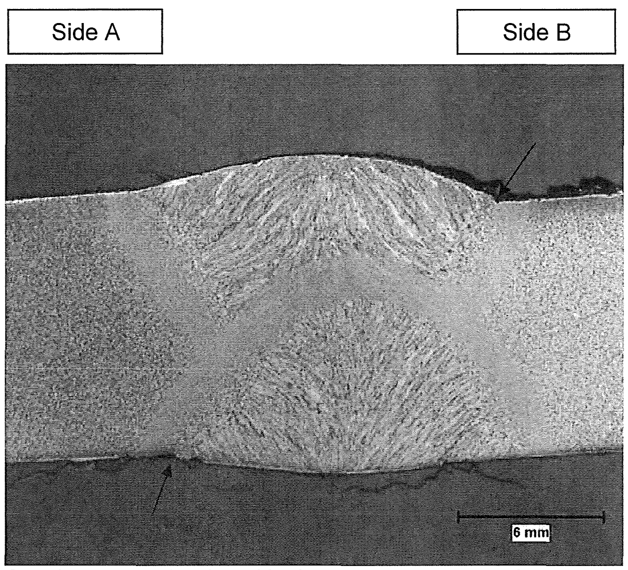
Lab # 743344-16 (Revised)



Specimen examined at 4X, photo shown at approximately 4X
Etched in 2% Nital

Figure 3: Photomacrograph of the Section 2, showing the pitting along the surface within the HAZ/at the weld toes.

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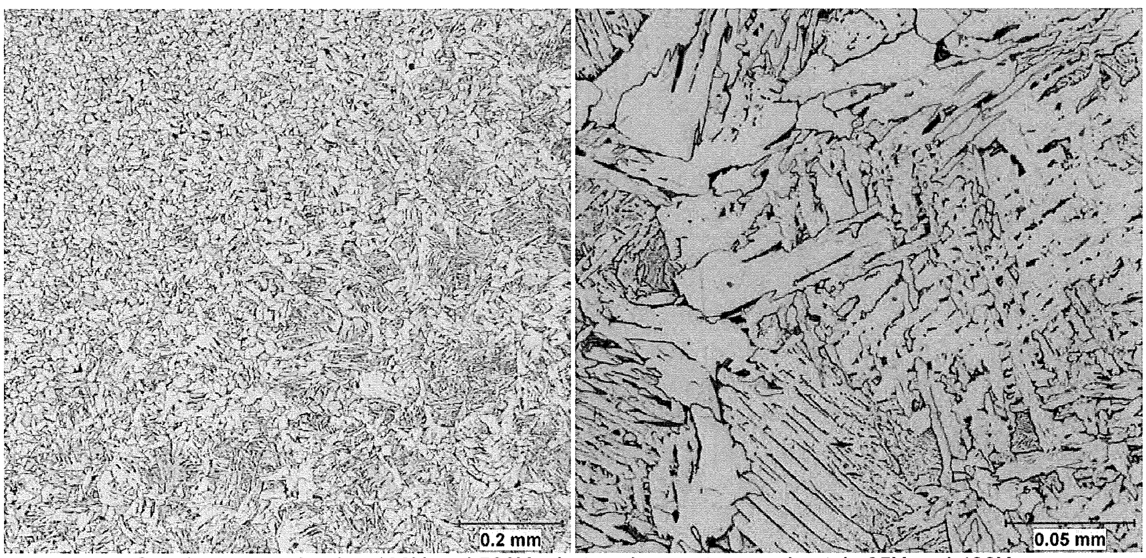
www.cambridgematerials.com

TEAM Industrial Services (NFLD)
Lab # 743344-16 (Revised)



Specimen examined at 100X and 500X, photos shown at approximately 85X and 428X
Etched in 2% Nital

Figure 4: Photomicrographs of the Section 1 “Side A” weld coupon at the “FL” location, where a relatively coarse grain HAZ of ferrite and some pearlite was observed.

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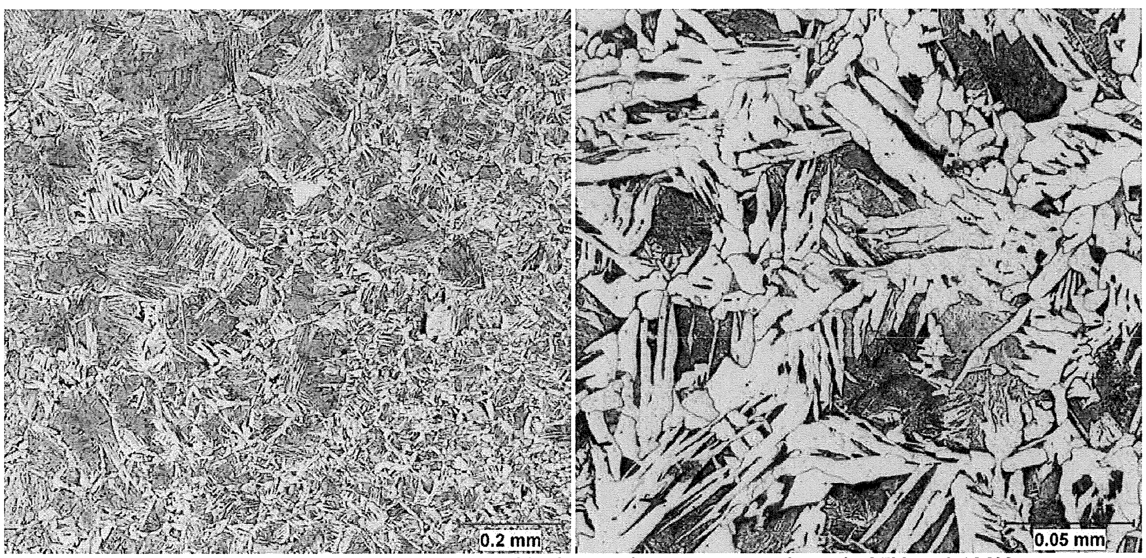

Specimen examined at 100X and 500X, photos shown at approximately 85X and 428X
Etched in 2% Nital

Figure 5: Photomicrographs of the Section 1 “Side B” weld coupon at the “FL” location, where a relatively coarse grain HAZ of ferrite and pearlite was observed.

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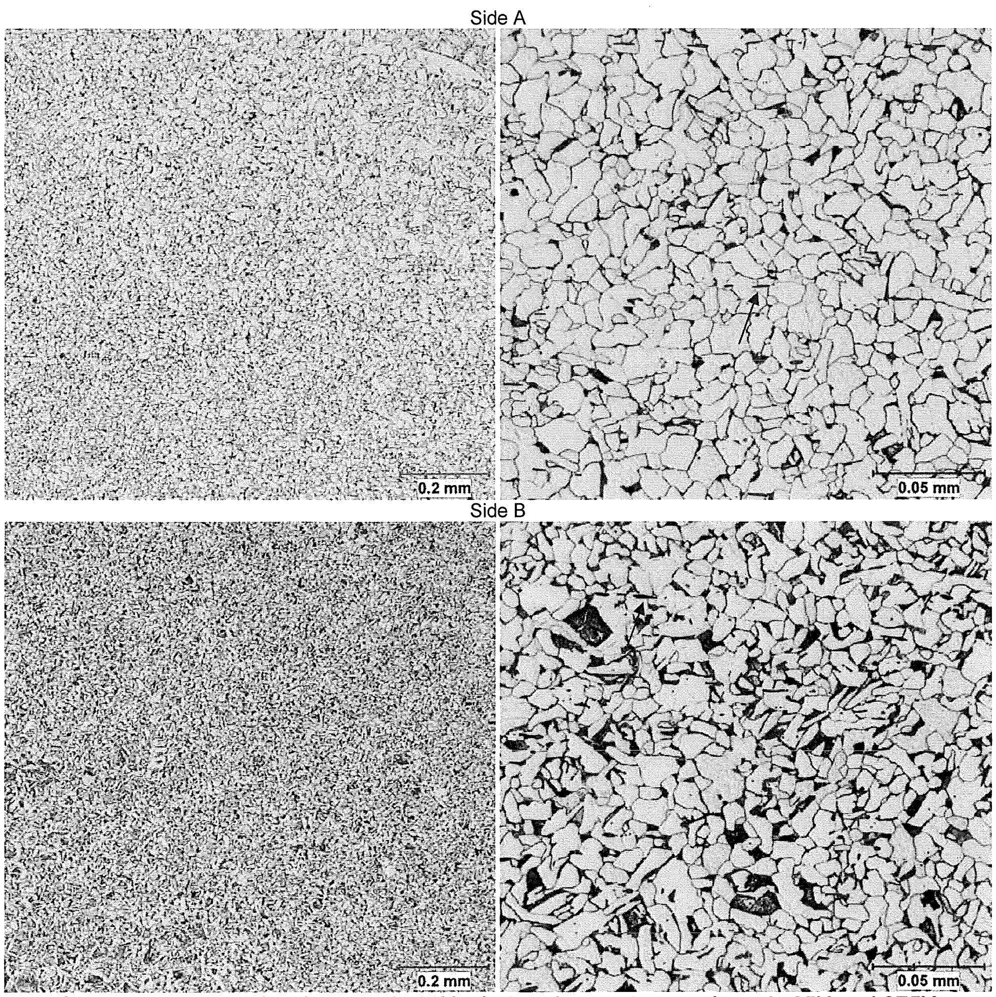

Specimen examined at 100X and 500X, photos shown at approximately 85X and 375X
Etched in 2% Nital

Figure 6: Photomicrographs of the Section 1 “Side A” and “Side B” weld coupon at the “FL +1” locations; where the HAZ microstructure showed a fairly uniform mixture of ferrite and pearlite, with a more refined grain size. At a higher magnification some sulphide inclusions were observed (refer to red arrows).

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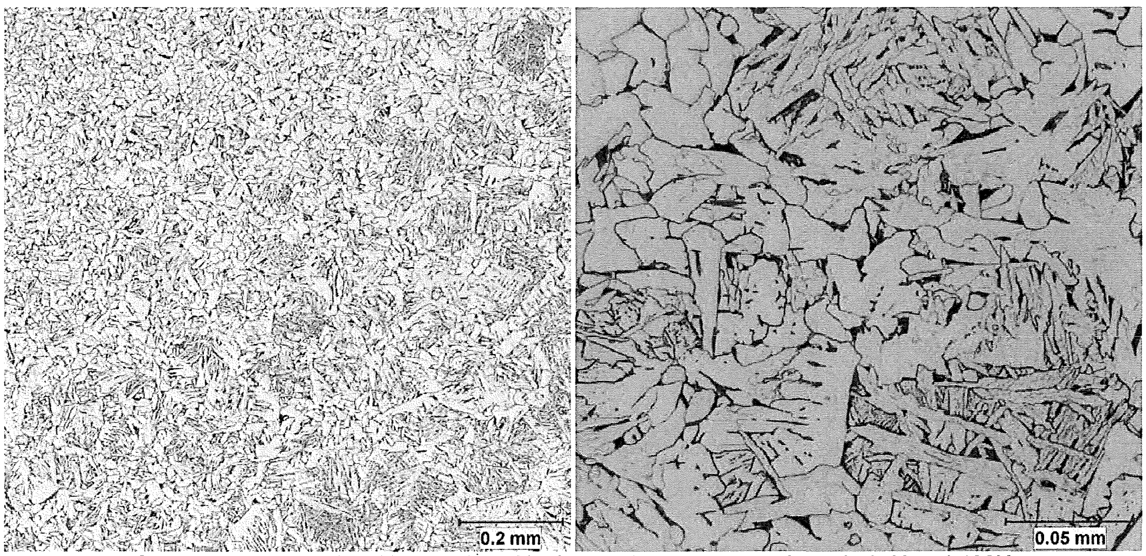

Specimen examined at 100X and 500X, photos shown at approximately 85X and 428X
Etched in 2% Nital

Figure 7: Photomicrographs of the Section 2 "Side A" weld coupon at the "FL" location, where a relatively coarse grain HAZ of ferrite and some pearlite was observed.

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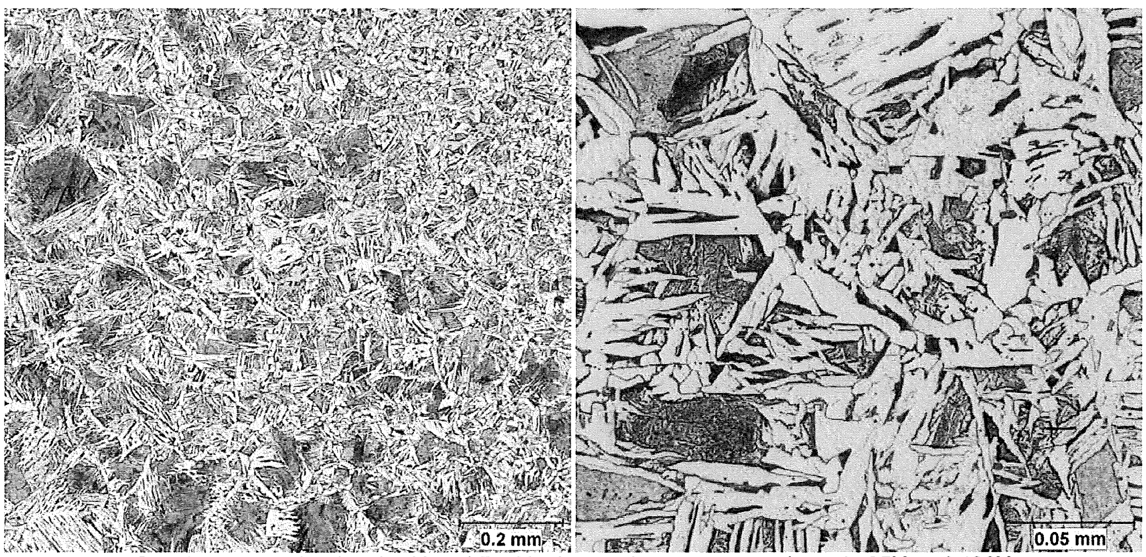

Specimen examined at 100X and 500X, photos shown at approximately 85X and 428X
Etched in 2% Nital

Figure 8: Photomicrographs of the Section 2 “Side B” weld coupon at the “FL” location, where a relatively coarse grain HAZ of ferrite and pearlite was observed.

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TEAM Industrial Services (NFLD)
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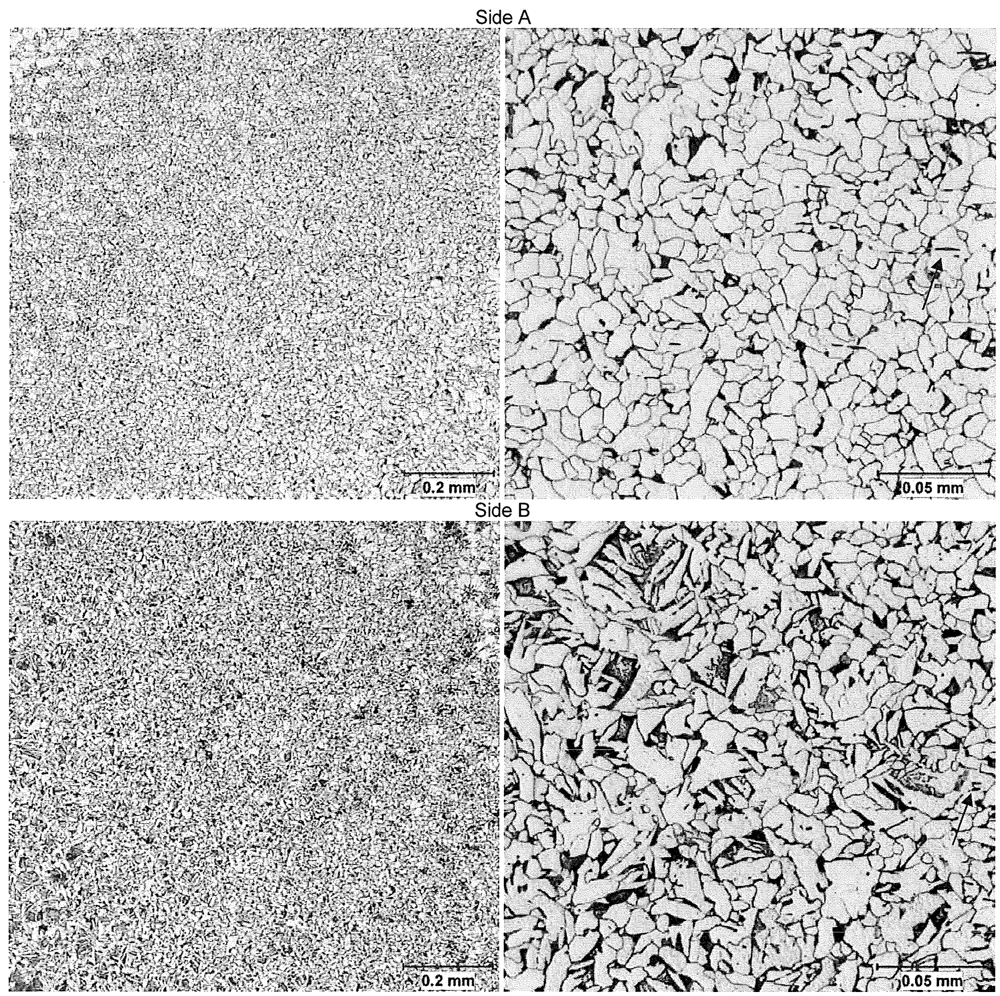

Specimen examined at 100X and 500X, photos shown at approximately 85X and 375X
Etched in 2% Nital

Figure 9: Photomicrographs of the Section 2 “Side A” and “Side B” weld coupon at the “FL +1” locations; where the HAZ microstructure showed a fairly uniform mixture of ferrite and pearlite, with a more refined grain size. At a higher magnification some sulphide inclusions were observed (refer to red arrows).

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Report for: TEAM Industrial Services (NFLD)
41 Sagona Avenue
MOUNT PEARL, Newfoundland
A1N 4P9

Laboratory No. 743345–16

Report Date: December 21, 2016
Received Date: December 12, 2016

Attention: Cyril Pretty

Specimen: For Hatch Limited, "Penstock" Weld Pipe Coupon, Sample #3 - Circumferential Seam, Material: ASTM A285 Gr. C

CHEMICAL ANALYSIS TEST REPORT

Total Carbon	0.098	%
Manganese	0.63	%
Phosphorus	0.010	%
Sulphur	0.032	%
Silicon	0.22	%

The above analysis is similar to the chemical composition limits of ASTM A285/A285M-12 Grade C steel, with the exception of Sulphur.

Chemical analysis performed according to ASTM E1019-11, ASTM E1097-12 (modified) and ASTM E1479-99(2011).

Cambridge Materials Testing Limited

Per Randi Lee
Randi Lee — *Quality Assurance*

Per Brittany DeGraaf
Brittany DeGraaf — *Technician*

Cambridge
materials testing limited

1177 Franklin Boulevard,
Cambridge, Ontario N1R 7W4
Tel: (519) 621-6600 Fax: (519) 621-6082
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Report for: TEAM Industrial Services (NFLD)
41 Sagona Avenue
MOUNT PEARL, Newfoundland
A1N 4P9

Laboratory No. 743346–16

Report Date: December 21, 2016
Received Date: December 12, 2016

Attention: Cyril Pretty

Specimen: For Hatch Limited, "Penstock" Weld Pipe Coupon, Sample #3 - Circumferential Seam, Material: ASTM A285 Gr. C

CHEMICAL ANALYSIS TEST REPORT

Total Carbon	0.091	%
Manganese	1.18	%
Phosphorus	0.015	%
Sulphur	0.023	%
Silicon	0.30	%

Chemistry was performed on the weld metal.

Chemical analysis performed according to ASTM E1019-11, ASTM E1097-12 (modified) and ASTM E1479-99(2011).

Cambridge Materials Testing Limited

Per Randi Lee
Randi Lee *Quality Assurance*

Per Brittany DeGraaf
Brittany DeGraaf *Technician*

Cambridge
materials testing limited

1177 Franklin Boulevard,
Cambridge, Ontario N1R 7W4
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Report for: TEAM Industrial Services (NFLD)
41 Sagona Avenue
MOUNT PEARL, Newfoundland
A1N 4P9

Laboratory No. 743347–16

Report Date: December 20, 2016
Received Date: December 12, 2016

Attention: Cyril Pretty

Specimen: For Hatch Limited, "Penstock" Weld Pipe Coupon, Sample #3 - Circumferential Seam, Material: ASTM A285 Gr. C

TRANSVERSE WELD TENSILE REPORT

	RESULT	
Specimen Width:	0.748	in.
Specimen Thickness:	0.377	in.
Cross Sectional Area:	0.282	in^2
Maximum Load:	17,880	lbf
Ultimate Tensile Strength:	63,500	psi

The tensile specimen fractured in the base metal in a ductile manner.

Testing performed according to ASME Boiler and Pressure Vessel Code Section IX (2015 Edition).

Cambridge Materials Testing Limited

Per Randi Lee
Randi Lee — Quality Assurance

Per Matthew Liska
Matthew Liska — Technician

Appendix D
Bay d'Espoir Pressure Conduit #1
Inspection Report 1987

HYDRO

BAY D'ESPOIR

PRESSURE CONDUIT #1

INSPECTION REPORT

NEWFOUNDLAND AND LABRADOR HYDRO

HYDRO

GENERATION & TRANSMISSION OPERATIONS
Engineering Services (Mech.)

BAY D'ESPOIR

PRESSURE CONDUIT #1

INSPECTION REPORT

Prepared by: Wayne Rice
Kevin J. Dawson

Date: September 9, 1987

HYDRO

INTRODUCTION

On September 2, 1987, Engineering Services personnel conducted an internal inspection of the #1 pressure conduit at the Bay D'Espoir Generating Station. This was the first such inspection of the conduit since it was placed in service in 1967. In general, the conduit appeared to be in excellent condition. No weld cracking, wall thinning or bulging was observed. This report contains details of the inspection procedure, details of the inspection process, which involved visual and ultrasonic methods, used and a listing of the inspection results.

DESCRIPTION OF PRESSURE CONDUIT

The #1 pressure conduit at BDE is an all-welded steel pipe approximately 3837 feet long and consists of three major sections. Between the intake structure and the surge tank the conduit is made up of approx. 1250 feet of 17' - 0" diameter ASTM A-285 Grade B carbon steel pipe and approx. 1000 feet of 15' - 3" diameter CSA Standard G-40.8 steel pipe . This section is known as "Pipeline A". From the surge tank to a point about 80 ft. upstream of the centre line of the units, the conduit consists of approx. 1476 feet of CSA Standard G-40.8 steel pipe. This section is known as "Penstock A". At this point the conduit bifurcates into two 9' - 6" diameter pipes, which are reduced to 7' - 3" diameter pipe and terminate at a spherical valve. There are no expansion joints. The thickness of the steel pipe varies from 7/16 inch to 1 5/8 inch depending on the location. The interior of the pressure conduit is coated with one coat of Matflint No. 7 -primer and one coat of Matflint No.7-black to achieve a total dry film thickness of 11 mils. Full details of the conduit layout, distances, grades and the coating specification can be found in appendix 1.

HYDRO

INSPECTION PROCEDURE

- PROCEDURE

The inspection procedure was as follows. Access to the conduit was gained through the unit scroll case. It should be noted that the original plan was to conduct the inspection at three locations by entering the conduit at the intake, through a manhole adjacent to the surge tank and through the unit scroll case . Due to the unavailability of a rope ladder (required to enter from the intake) and the rusted condition of the manhole cover bolting, it was decided that it would be faster to enter the conduit through the unit and to walk from the unit to the intake with the inspection being carried out on the return trip. The inspection was primarily visual. Each weld was inspected, the general condition of the conduit plating and coating observed and random thickness measurements taken.

- EQUIPMENT

DM-2 Thickness meter and couplant
Flashlights (One per person plus a spare)
Camera
Rain Suits, hard hats, rubber boots and gloves

- SAFETY

The decay of vegetation and animal matter within conduits of this type can produce pockets of methane gas. A substantial air flow, probably due to the venting effect of the surge tank, was observed at the scroll case. Due to this, gas measurements were not considered to be required, however, this decision should be re-assessed each time the conduit is entered. It is also recommended that a radio be carried. None were available for this inspection. The slope in most of the conduit is not extremely steep and therefor it was not necessary to have ropes laid down to aid travel. However, caution was exercised while walking especially on the steeper slope sections. Again, this should be assessed on a case by case basis.

HYDRO

INSPECTION RESULTS

- VISUAL

Inspection of the intake gate revealed only minor leaks around its perimeter, the largest being at the bottom right hand corner. Water seepage was observed at the intake concrete to steel transition section of the conduit. The location of this leakage is indicated on dwg. F 105 C-2 in Appendix 1. In light of the present problems being experienced with the intake dyke, this leakage should be monitored. When the conduit is under pressure, the leakage flow is reversed and blockage of the box drains could allow a build-up of water within the dyke. This information has been passed to Bob Barnes and to Mr John Young of ACRES.

In the conduit itself, all section welds were visually inspected with no damage being found. The conduit plating was also inspected. Throughout the length of the complete conduit there is a heavy build-up of what appears to be rust/organic, magnetic material approx. .200 inch to .300 inch thick. This buildup has sheared off in a sheet fashion at numerous locations, especially adjacent to section welds and by as much as 25% in the following areas: (Ref. Drawing F-106-C-11, Appendix 1).

1. Section 3A - 250.01'
2. Near the lower end of section 8A below the surge tank.

In general, in areas where the heavy build-up has been dislodged only a thin layer of surface corrosion is apparent. The underlying metal appears to be in excellent condition however there appears to be no Matflint coating. It is suspected that the Matflint coating failed and thus allowed water to react with the metal which in turn produced the rust build-up. The black colour of the water side of the build-up suggests that the residue of the Matflint coating is, in fact, the top layer of the deposit. Photographs of the build-up can be found in Appendix 2. A laboratory analysis of the deposit is in progress.

HYDRO

- ULTRASONIC INSPECTION

Random pipe wall thicknesses were recorded at twelve locations along the penstock. These are listed in Table 1, with their locations and corresponding values from drawing F-106-C-11. The approximate locations of these readings are also shown on F-106-C-11, Appendix 1.

TABLE 1

THICKNESS READING NO.	LOCATION	MEASURED THICKNESS (in)	SPECIFIED THICKNESS (in) DWG. F-106-C-11
1	Sect. 1A, 12 welds from start of penstock.	0.540	0.500
2	Sect. 2A, Weld #20	0.462	0.438
3	Sect. 2A, Weld #30	0.462	0.438
4	Sect 3A, Weld #22	0.438	0.438
5	Sect 4A, Weld #42	0.490	0.438
6	Sect 7A-8A, Weld #20	0.725	0.750
7	Sect 7A-8A, Weld #65	0.880	0.813
8	Sect 9A, 3 Welds Upstream of start of 11° Sect 10A	1.167	1.188
9	Sect 10A, Weld #12	1.293	1.250
10	Sect 10A, Weld #24	1.330	1.313
11	Sect 10A, Weld #38	1.393	1.375
12	Sect 10A, Weld #48	1.490	1.438

HYDRO

APPENDIX I

C5 - PROTECTIVE COATING

C5.1 PREPARATION

The internal surface of the conduit, and the external surface of the conduit within six inches of field welds shall be given a coat of boiled linseed oil or an equal temporary coating to protect them during transit and storage.

The external surface of the conduit which will be bonded to concrete after embedment shall be cleaned by power wire brushing in accordance with Specification SSPC-P53-52T and shall then be given one coat of cement-latex milk prior to shipment. The cement-latex milk shall consist of ten parts Portland Cement (by weight), five parts water, and one part of modified latex emulsion.

All other areas of the external surface of the pipe shall be protected by cleaning and prime coating in the Contractor's shop, followed by finishing coats applied in the field and/or shop.

Necessary safety precautions shall be taken to avoid fire, explosion or danger to human health. All paints shall be applied under dry conditions, when the temperature is not below 55°F and the surface to be painted is devoid of moisture condensation.

(a) Cleaning

Heavy deposits of oil or grease shall be removed by wiping or scrubbing the surface with rags or brushes wetted with solvent. The final wiping shall be done with clean solvents and clean rags or brushes.

(b) Blast Cleaning

All surfaces shall be given a "grey" or "commercial" blast cleaning in accordance with Canadian Government Specification Board Spec. 31-GP-404 latest revision.

(c) Post-Blast Cleaning

After dry-blast cleaning, the surface shall be dusted off or blown off with compressed air, free of detrimental oil and water. If wet-blasted, the surface shall be cleaned by rinsing with fresh water to which sufficient corrosion inhibitor has been added to prevent rusting. This treatment shall be supplemented by brushing, if necessary, to remove any residue.

C5.2 APPLICATION

(a) First Prime Coat

The blast-cleaned surface shall be primed within 8 hours unless other precautions are taken to prevent rusting before application of prime coat. The primer used shall be Crown Diamond Phenix Epoxy Red Lead Primer No. 100. It can be applied only by brush or roller. When applied at the rate of 450-500 square feet per gallon, it will leave a minimum dry film thickness of one mil. These limits must be adhered to and are subject to approval after completion. Care should be taken to avoid any unnecessary damage after painting.

(b) Second Coat of Primer

After all work has been completed, a second coat of the specified primer shall be applied by brush, roller or spray at a rate of 450-500 square feet per gallon resulting in a minimum dry film thickness of one mil. These limits must be adhered to. A minimum period of 24 hours drying time is required before application of the second primer coat.

(c) Finishing Coat

When the priming coats are thoroughly dry, the pipe shall be given one coat of Hilson No. 330 Mastic or equal, containing asbestos fibres. This shall be applied at a minimum rate of 5 gallons per 100 square feet. The temperature must be above 40°F during this application.

Immediately following the application of this coating, and before it dries, the pipe shall be wrapped with a layer of 7 - 1/2 oz jute hessian embedded in the mastic. This jute shall be wrapped so as to have a minimum overlap between turns of three inches.

A second coat of Hilson No. 330 Mastic compound consisting of 2 gallons per 100 square feet shall then be applied over the jute. Each gallon of this coating shall be cut back with one quart of a suitable petroleum solvent.

(C5. 2) (c) Finishing Coat (Cont'd)

The priming coats must be applied in the Contractor's shop but the emulsion and jute hessian protective coatings may be applied in the shop or on Site, at the Contractor's option, provided that a continuous prime coat exists before the bitumastic compound is applied. The Hilson compound must be thoroughly dry before the pipe is moved.

C5. 3 APPLICATION OF INTERIOR COATING

(a) Prime Coat

The blast-cleaned surface (prepared as per Clause C5. 1) shall be primed within 8 hours to prevent rusting. The first coat shall be a Matflint No. 7 primer, applied by brush only at a rate of 260 square feet per gallon. The dry film thickness shall not be less than 5 mils. Care should be taken that no areas are skipped, that pin-holes are avoided and uniformity of the prime coat is assured.

(b) Finishing Coat

When the prime coat is thoroughly dry, the pipe shall be given one coat of Matflint No. 7 - black, applied by brush or roller at a rate of 260 square feet per gallon giving a dry film thickness of not less than 6 mils. If brush is used the finishing strokes shall be made in the direction of flow of water in pipes. The temperature must be above 50°F during this application.

C5. 4 PROVISION FOR CANCELLATION

The work described under Clause C5. 3 above may be cancelled, at any time, at the sole discretion of the Owner. In the event of the Owner exercising such a perogative no payment shall be made under this item.

February 11, 1965.

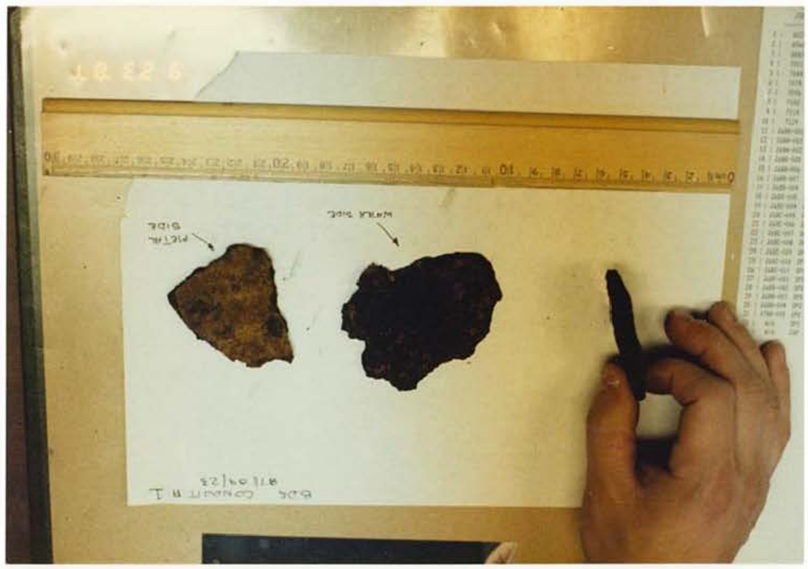
DRWING #'s F-105-C-2
"INTAKES No.1 & No.2"
CONCRETE DETAILS.

F-106-C-11
"PRESSURE CONDUITS"
LAYOUT & LOCATION DATA.

HYDRO

APPENDIX 2

PHOTOGRAPHS OF
#1 PRESSURE CONDUIT
INTERIOR COATING.



Appendix E
Water Chemistry Reports

ACUREN

Laboratory Report

Client			Laboratory Report
Hatch 370 Torbray Road Bally Rou Place, Suite E200 St. John's, NF A1A 3W8			
Attention	*Client's Order Number*	*Date*	*Report Number*
Michael Pyne	N/A	Jan. 18, 2017	128-17-10HAT004-0001 Rev. 0

Client's Material /Product Description	*Date Sample Received*	*Material / Product Specification*
Quantity: 3 Water samples	Dec. 28, 2017	-----

1. Analysis for pH*

	UNITS	SAMPLE #1	SAMPLE #2	SAMPLE #3
pH	pH	7.67	7.52	7.42

Address
2421 Drew Road
Mississauga, ON
Canada
L5S 1A1

Telephone
(905)673-9899

Facsimile
(905)673-8394

Website
www.acuren.com

2. Total Metals Analysis by ICPMS*

Metals	UNITS	SAMPLE #1	SAMPLE #2	SAMPLE #3	RDL
Total Aluminum (Al)	mg/L	0.053	0.050	0.049	0.0050
Total Antimony (Sb)	mg/L	<0.00050	<0.00050	<0.00050	0.00050
Total Arsenic (As)	mg/L	<0.0010	<0.0010	<0.0010	0.0010
Total Barium (Ba)	mg/L	<0.0020	<0.0020	<0.0020	0.0020
Total Beryllium (Be)	mg/L	<0.00050	<0.00050	<0.00050	0.00050
Total Bismuth (Bi)	mg/L	<0.0010	<0.0010	<0.0010	0.0010
Total Boron (B)	mg/L	<0.010	<0.010	<0.010	0.010
Total Cadmium (Cd)	mg/L	<0.00010	<0.00010	<0.00010	0.00010
Total Calcium (Ca)	mg/L	1.1	1.1	1.0	0.20
Total Chromium (Cr)	mg/L	<0.0050	<0.0050	<0.0050	0.0050
Total Cobalt (Co)	mg/L	<0.00050	<0.00050	<0.00050	0.00050

ISO 9001:2008 QUASAR REGISTERED

ACCREDITED
CERT #3977.01 & 3977.04

ACUREN

Laboratory Report

Total Copper (Cu)	mg/L	<0.0010	<0.0010	<0.0010	0.0010
Total Iron (Fe)	mg/L	<0.10	<0.10	<0.10	0.10
Total Lead (Pb)	mg/L	<0.00050	<0.00050	<0.00050	0.00050
Total Lithium (Li)	mg/L	<0.0050	<0.0050	<0.0050	0.0050
Total Magnesium (Mg)	mg/L	0.35	0.35	0.34	0.050
Total Manganese (Mn)	mg/L	<0.0020	<0.0020	<0.0020	0.0020
Total Molybdenum (Mo)	mg/L	<0.00050	<0.00050	<0.00050	0.00050
Total Nickel (Ni)	mg/L	<0.0010	<0.0010	<0.0010	0.0010
Total Potassium (K)	mg/L	<0.20	<0.20	<0.20	0.20
Total Selenium (Se)	mg/L	<0.0020	<0.0020	<0.0020	0.0020
Total Silicon (Si)	mg/L	0.47	0.46	0.46	0.050
Total Silver (Ag)	mg/L	<0.00010	<0.00010	<0.00010	0.00010
Total Sodium (Na)	mg/L	1.5	1.4	1.4	0.10
Total Strontium (Sr)	mg/L	0.0053	0.0047	0.0043	0.0010
Total Tellurium (Te)	mg/L	<0.0010	<0.0010	<0.0010	0.0010
Total Thallium (Tl)	mg/L	<0.000050	<0.000050	<0.000050	0.000050
Total Tin (Sn)	mg/L	<0.0010	<0.0010	<0.0010	0.0010
Total Titanium (Ti)	mg/L	<0.0050	<0.0050	<0.0050	0.0050
Total Tungsten (W)	mg/L	<0.0010	<0.0010	<0.0010	0.0010
Total Uranium (U)	mg/L	<0.00010	<0.00010	<0.00010	0.00010
Total Vanadium (V)	mg/L	<0.00050	<0.00050	<0.00050	0.00050
Total Zinc (Zn)	mg/L	<0.0050	<0.0050	<0.0050	0.0050
Total Zirconium (Zr)	mg/L	<0.0010	<0.0010	<0.0010	0.0010

RDL – Reportable Detection Limit

Address
2421 Drew Road
Mississauga, ON
Canada
L5S 1A1

Telephone
(905)673-9899

Facsimile
(905)673-8394

Website
www.acuren.com

ACUREN

Laboratory Report

Jennifer Pollock, EIT
Metallurgist

Dr. Erhan Ulvan, Ph.D, P.Eng
Manager - Central Region Engineering and Laboratory

The Client Representative who receives this report is responsible for verifying that any acceptance standards listed in the report are correct, and promptly notifying Acuren of any issues with this report and/or the work summarized herein. The owner is responsible for notifying Acuren in writing if they would like their samples returned or placed into storage (at their cost) otherwise, all samples/specimens associated with this report will be disposed of 60 days after the report date.

NOTES:

A) Any tests subcontracted to an approved subcontractor are highlighted above (*)

B) Levels of Services :Regular Service: 3 to 5 business days; Next Day Service: 8 to 16 business hours; Same Day Service: within 8 business hours; Super Rush: Work will commence immediately regardless of the time and will continue until it is completed

C) The Client will be notified if completion of test will exceed the time specified as a result of the volume of work or the complexity of the test

D) The Client should specify the standards used for testing/comparison purpose. We have a comprehensive library and online subscription of commonly used standards, however, we may ask the client to supply the standards if not common or the Client requests to purchase standard(s) on his behalf.

E) Please provide all the necessary information/documents (MSDS) pertaining to any Toxic / Dangerous materials prior to their arrival in the Laboratory.

Address
2421 Drew Road
Mississauga, ON
Canada
L5S 1A1

Telephone
(905)673-9899

Facsimile
(905)673-8394

Website
www.acuren.com

CERT #3977.01 & 3977.04

TABLE I

ANALYSIS OF BAY D'ESPOIR WATER

Parameter	Concentration (ppm except as noted)
pH	5.59
Conductivity (umhos/cm)	28.5
TDS	11.4
Alkalinity (ppm $CaCo_3$)	2.5
Fluoride	<0.1
Chloride	3.0
Nitrite	<0.1
Bromide	<0.1
Nitrate	0.04
Phosphate	<0.1
Sulphite	<0.1
Sulphate	2.6
Cobalt	<0.01
Zinc	1.2
Cadmium	<0.02
Boron	<0.02
Bismuth	<0.2
Phosphorus	<0.5
Beryllium	<0.002
Silicon	0.62
Iron	0.12
Manganese	0.02
Calcium	16
Magnesium	0.54
Copper	<0.01
Aluminum	<0.15
Vanadium	<0.01

1988

Form WAF-3 1M 2/78

WATER ANALYSIS FACILITY
Department of Chemistry (C-411)
Memorial University of Newfoundla

NALYTICAL RESULTS

omitted by: John Noel - Hydro Phone: Date: Nov. 14 19 80

dress: Bill to: Approved: (authorized representative)

ser's sample code: Baie d'Espoir #4

ater analysis code: 3844

te complete: 19 Signed:

	Parameter	Value	Units		Parameter	Value	Un
1.	Alkalinity	2	mg/L $CaCO_3$	12.	Calcium	0.94	mg/L
2.	Acidity		mg/L $CaCO_3$	13.	Magnesium	0.38	mg/L
3.	Apparent colour		TCU	14.	Manganese	$<$ 0.01	mg/L
4.	Hardness	4.09	mg/L $CaCO_3$	15.	Iron	0.10	mg/L
5.	Kjeldahl nitrogen		mg/L N	16.	Copper		mg/L
6.	Nitrate	0.044	mg/L N	17.	Zinc		mg/L
7.	pH	5.19	units	18.	Cadmium		mg/L
	Total phosphorus	0.016	mg/L PO_4		Lead		mg/L
	Specific conductance	20	micromhos/cm		Sodium		mg/L
	Turbidity		NTU		Potassium		mg/L
	Chemical oxygen demand		mg/L COD		silicate	0.328	mg/L
	Fluoride	0.023	mg/L F		nitrite	$<$ 0.005	mg/L
	Chloride	9	mg/L Cl		Bicarb. Alkalinity	2	mg/
	Biochemical Oxygen demand		mL/L		Carb. Alkalinity	$<$ 1	mg/
	Dissolved oxygen		mL/L		Tot. Suspended Solids	$<$ 5	mg/
	Ortho phosphate	$<$ 0.005	mg/L PO_4		Tot. Dissolved solids	31	mg

MENTS:

*Canadian "Drinking Water Standards" upper limit or recommended range.

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MONTREAL 25, CANADA

REPORT OF ANALYSIS

Shawmont Engineering Newfoundland Ltd.,
1010 Beaver Hall Hill,
Montreal, Que.

Attn: Mr. A. Bonnell

LABORATORY NO. 1382

DATE RECEIVED Mar. 2, 1965

SAMPLE OF Water

MARKED

		Parts per million
Suspended Matter		0.2
Total Iron (Fe)		0.1
Turbidity		0
Analysis of Filtered Sample		
Total Solids on Evaporation		25.8
Silica (SiO_2)		1.4
Calcium (Ca)		1.6
Magnesium (Mg)		0.5
Alkalies as Sodium (Na) Calc.		1.6
Sulphate (SO_4)		0.7
Chloride (Cl)		1.7
Bicarbonate (HCO_3)		7.9
Carbon Dioxide (CO_2)		[illegible]
Colour		[illegible]
pH	6.1	
Total Hardness as $CaCO_3$		6.0
Carbonate Hardness as $CaCO_3$		6.0
Non-Carbonate Hardness as $CaCO_3$		Nil
Carbonate Alkalinity as $CaCO_3$		Nil
Bicarbonate Alkalinity as $CaCO_3$		6.5
Hypothetical Combination		
Calcium Bicarbonate $Ca(HCO_3)_2$		6.5
Magnesium Bicarbonate $Mg(HCO_3)_2$		3.0
Sodium Bicarbonate $NaHCO_3$		0.7
Sodium Sulphate Na_2SO_4		1.0
Sodium Chloride NaCl		2.8
Silica SiO_2		1.4
Iron Oxide Fe_2O_3		0.1

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TABLE 3.2A

WATER ANALYSIS REPORT SUMMARY

PARAMETER	UNIT OF MEASURE	CDWQG STANDARD		BAY D'ESPOIR POWERHOUSE NO. 1				
		MAC[1]	AO[2]	OCT.92	NOV.93	NOV.94	MAY 95	MAY 96
Alkalinity	mg/L $CaCO_3$			3.66	3.3	—	—	—
Apparent Color	TCU[3]		≤15	33	48	32	31	33
Hardness (requires Ca,Mg)	mg/L $CaCO_3$		80–100	2.7	3.2	2.6	3.1	3.4
Kjeldahl Nitrogen	mg/L N			0.18	0.10	0.24	0.10	0.10
Nitrate (+nitrite)	mg/L N	45		0.061	0.035	0.060	0.067	0.0043
pH	Units		6.5–8.5	6.21	6.19	6.28	6.18	7.04
Total Phosphorus	mg/L PO_4			<0.02	<0.02	—	—	—
Specific Conductance	µmhos/cm			18.0	14.9	20.2	18.3	15.3
Turbidity	NTU[4]	1.0	5.0[5]	1.05	2.30	0.29	0.44	0.33
Chemical Oxygen Demand	mg/L COD			12	11	10	—	11
Calcium	mg/L Ca			0.62	0.73	0.53	0.72	0.84
Magnesium	mg/L Mg			0.28	0.33	0.31	0.31	0.32
Manganese	mg/L Mn		≤0.05	<0.005	<0.005	—	0.02	<0.005
Iron	mg/L Fe		≤0.30	0.04	0.05	0.08	0.07	0.06
Copper	mg/L Cu		≤1.0	0.19	0.16	0.09	0.06	0.08
Zinc	mg/L Zn		≤5.0	<0.005	<0.005	<0.005	<0.005	<0.005
Cadmium	mg/L Cd	0.005		<0.005	<0.005	—	—	—
Lead	mg/L Pb	0.010		0.004	0.003	<0.001	0.002	<0.001
Chloride	mg/L Cl		≤250	1.7	1.5	4.1	2.6	1.9
Sodium	mg/L Na		≤200	1.54	1.14	—	—	—
Potassium	mg/L K			0.22	0.18	—	—	—
Ammonia	mg/L N			<0.02	<0.02	—	—	—
Dissolved Oxygen	mg/L O			—	—	—	<0.05	—
Fluoride	mg/L F	1.5		0.08	<0.05	<0.05	—	<0.05
Sulfate	mg/L SO_4		≤500	2.1	1.1	1.7	3.7	2.2
Total Dissolved Solids	mg/L		≤500	12	10	16	15	13
Total Suspended Solids	mg/L			<4	<4	<4	<4	<4
Total Organic Carbon	mg/L C			3.7	—	3.8	3.9	4.1
Mercury	mg/L Hg	0.001		—	<0.00005	—	—	—

[1] MAC Maximum Acceptable Concentration
[2] AO Aesthetic Objective
[3] TCU True Color Units
[4] NTU Nephelometric Turbidity Units
[5] At point of consumption

Appendix F
Acuren Test Reports

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Laboratory Report

Client	Laboratory Report		
Hatch 370 Torbray Road Bally Rou Place, Suite E200 St. John's, NF A1A 3W8			
Attention	*Client's Order Number*	*Date*	*Report Number*
Michael Pyne	RFA	February 7, 2017	128-17-10HAT004-0001 Rev. 0

Client's Material /Product Description	*Date Sample Received*	*Material / Product Specification*
Quantity: 3 Weld Samples, 3 Water samples, and 2 Algae Samples	December 28, 2017	-----

1. <u>Galvanic Test</u>

Figure 1 illustrates the as-received samples. In Sample 1, the weld is along the longitudinal direction of the tank, while in Samples 2 and 3, the weld is along the circumferential direction of the tank. Table 1 lists the chemical composition of the base metal and the electrode used for the welding process.

Figure 1. Low magnification morphology of HAZ-Metal couple sample 1.

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Table 1. Base metal and electrode used for welding process

Sample #	1	2	3
Base Metal	ASTM 285-C	CSA G40.8-B	ASTM 285-C
Welding Electrode	E7018	E7018	E7018

Coupons of approximately 10×10 mm^2 were cut from the fusion zone (weld), heat affected zone (HAZ), and base metal (BM) of all the samples listed in Table 1. Please be advised that as the HAZ was very narrow with a ">" shape on one side and a "<" on the other side, we took utmost care to extract sample from that specific zone, however there is a slight chance that the extracted part would not be completely from one single region (i.e. HAZ, weld, base metal). Sample was then grinded with 600 grit sandpaper, washed with soap and rinsed with deionized water and 99.9% ethanol.
Corrosion tests were carried out at ambient temperature for one hour in an acidic solution with a pH of 6.25 prepared by nitric acid (HNO_3) diluted in deionized water (DI). Each test was repeated twice as per ASTM G71 – 81 (2014). Table 2 lists the results of galvanic tests for all three samples. Corrosion rate is reported in mpy.

Table 2. Galvanic corrosion rate of all samples

Sample #			1	2	3
WELD/HAZ	Test 1	Corrosion Rate (mpy)	1.20	0.09	0.97
		Corroded Part	WELD	Both	HAZ
	Test 2	Corrosion Rate (mpy)	0.51	0.09	0.23
		Corroded Part	WELD	Both	Both
WELD/BM	Test 1	Corrosion Rate (mpy)	0.18	0.05	0.37
		Corroded Part	Both	Both	Both
	Test 2	Corrosion Rate (mpy)	0.51	0.18	1.70
		Corroded Part	BM	Both	Weld
HAZ/BM	Test 1	Corrosion Rate (mpy)	0.28	0.05	0.83
		Corroded Part	Both	Both	HAZ
	Test 2	Corrosion Rate (mpy)	1.24	0.09	1.43
		Corroded Part	BM	Both	Both

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<u>**Visual Examinations**</u>
Figures 2 to 10 present low magnification morphology of samples after galvanic testing. It should be noted that almost all of the corroded samples show pitting corrosion as well.

<u>*Sample 1:*</u>
Figure 2 shows that for HAZ/BM couple, both of them were corroded in test 1, while BM was protected in test 2 and there is no sign of pitting corrosion. Figure 3 depicts that both parts were corroded in test 1 for WELD/BM couple, but BM was protected in test 2. As

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shown in Figure 4, HAZ was protected in both tests against the WELD. Based on the observations, it can be suggested that the weld has the least corrosion resistance in the galvanic setup and BM shows the best corrosion resistance.

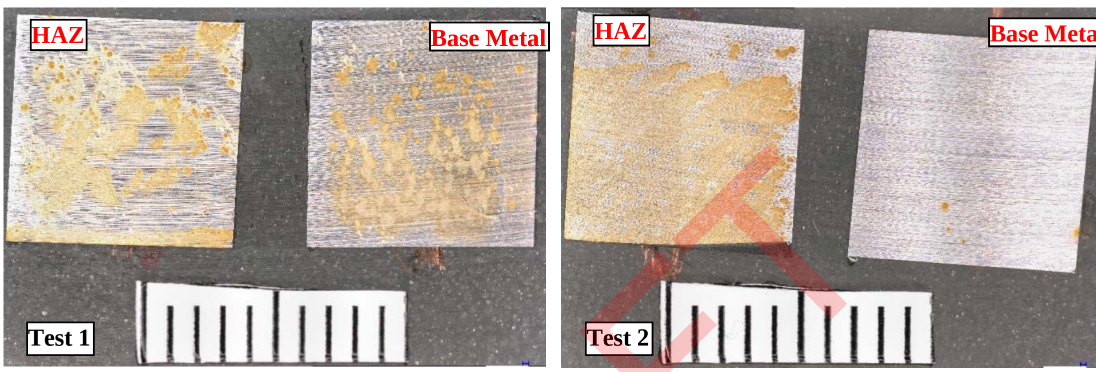

Figure 2. Low magnification morphology of HAZ/BM couple Sample 1.

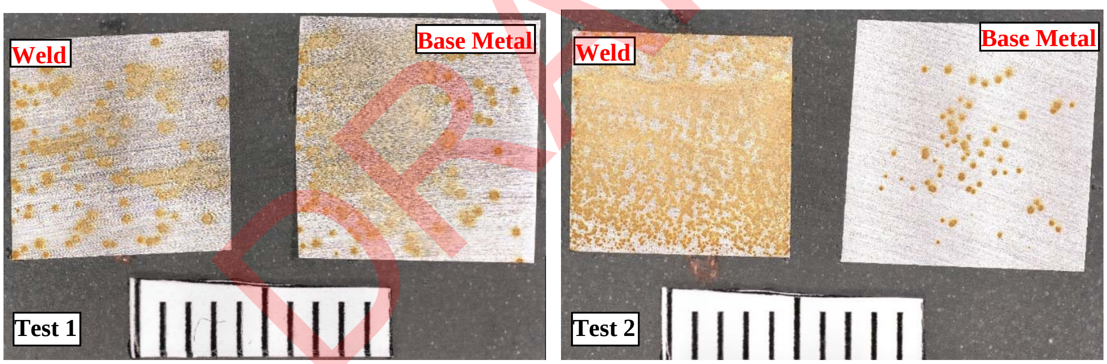

Figure 3. Low magnification morphology of WELD/BM couple Sample 1.

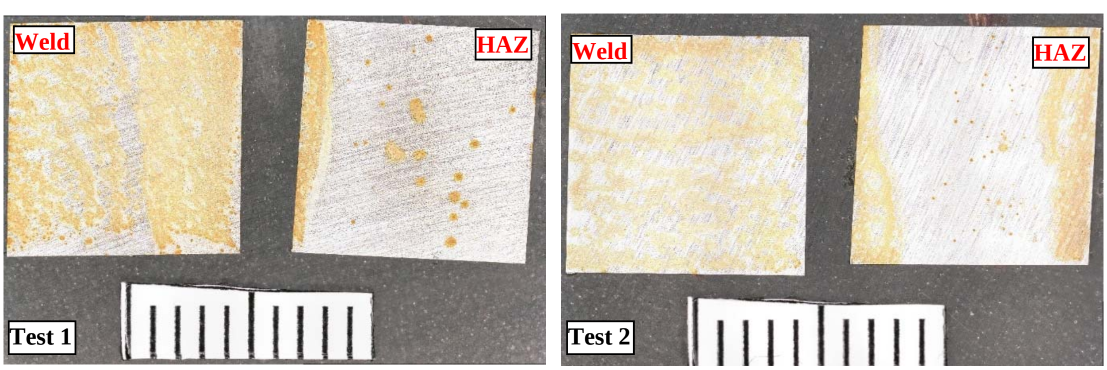

Figure 4. Low magnification morphology of WELD/HAZ couple Sample 1.

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Sample 2:

Figure 5 suggests that both HAZ and BM were corroded in both tests. For WELD/BM couple, both parts were corroded in both tests as shown in Figure 6. Figure 7 depicts that both WELD and HAZ regions were corroded in both tests. In total, it appears that none of the three regions is protected against one another, and pitting corrosion is a major feature on the surfaces of all samples.

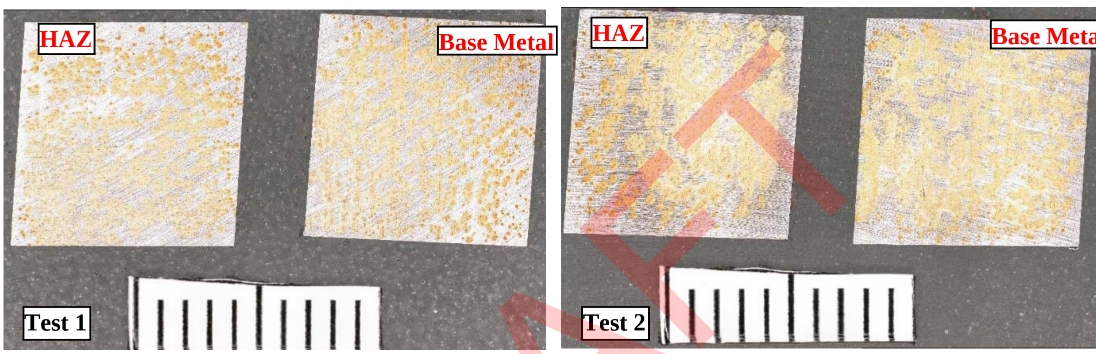

Figure 5. Low magnification morphology of HAZ-Metal couple Sample 2.

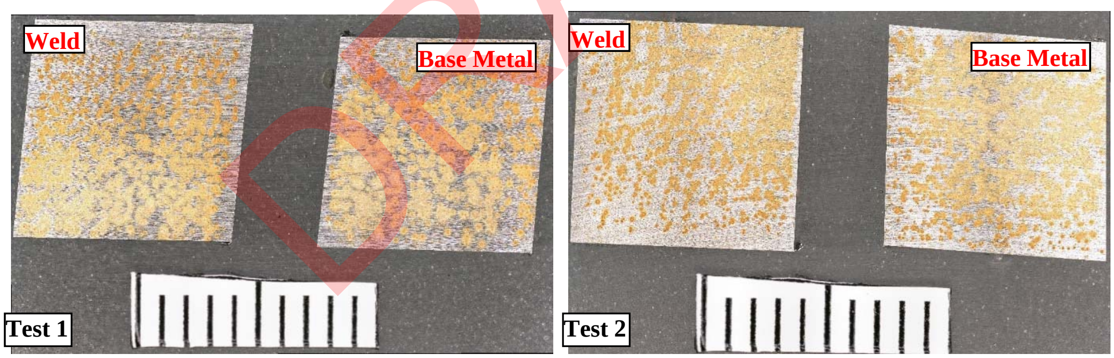

Figure 6. Low magnification morphology of Weld-Metal couple Sample 2.

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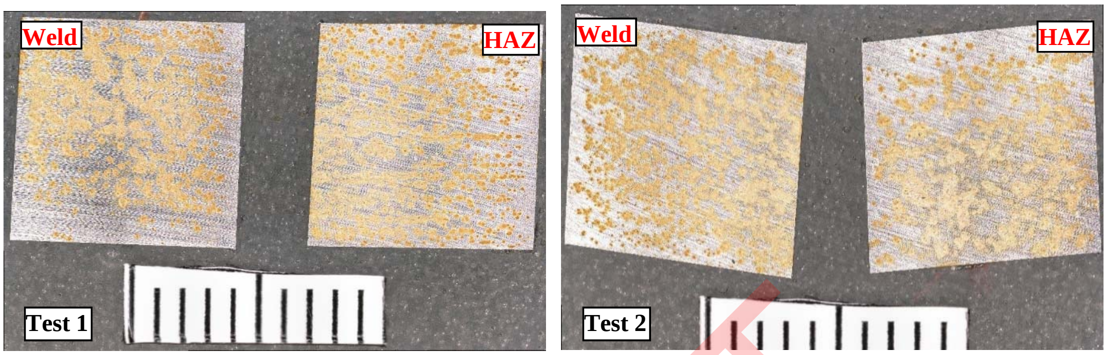

Figure 7. Low magnification morphology of Weld-HAZ couple Sample 2.

Sample 3:

From Figure 8, it appears that HAZ was protected against BM in HAZ/BM galvanic couple. As for WELD/BM couple (Figure 9), both parts were corroded in test 1. In the second test, WELD is corroded, while BM is slightly corroded. As shown in Figure 10, in WELD/HAZ couple, the first test shows HAZ is corroded and WELD is protected, while in the second test, Weld is also corroded similar to HAZ.

In General, it seems that apart from general corrosion of different parts of the weld joint, there is a possibility that HAZ could suffers from galvanic corrosion against WELD.

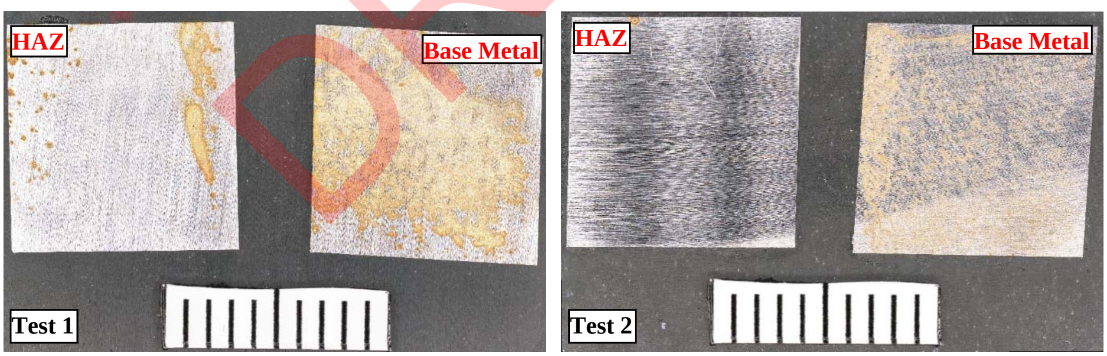

Figure 8. Low magnification morphology of HAZ-Metal couple Sample 3.

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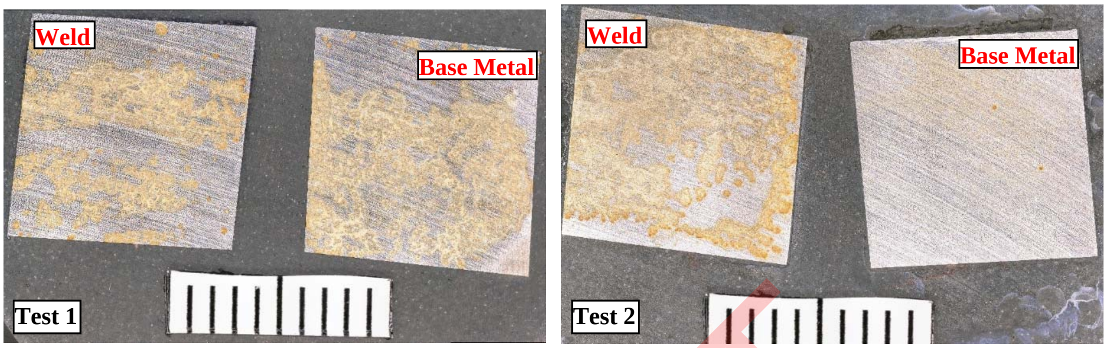

Figure 9. Low magnification morphology of Weld-Metal couple Sample 3.

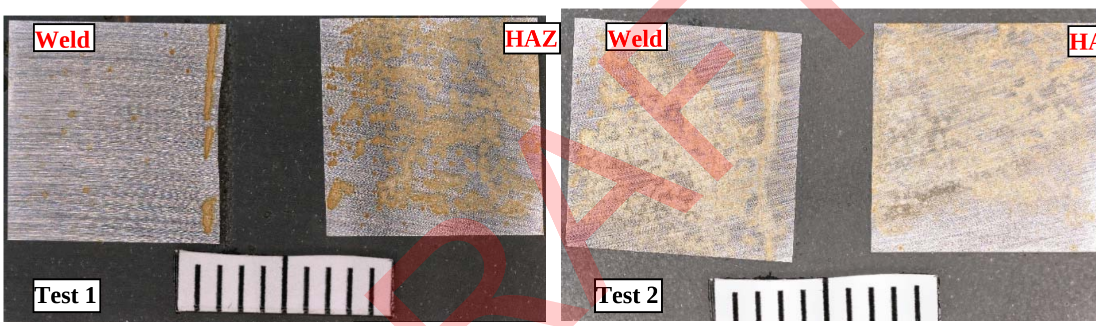

Figure 10. Low magnification morphology of Weld-HAZ couple Sample 3.

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Reference Samples:

As it can be observed in Figure 11, samples show no significant corrosion after on hour of exposure to similar solution used for galvanic test. This indicates the severity of galvanic corrosion for this design.

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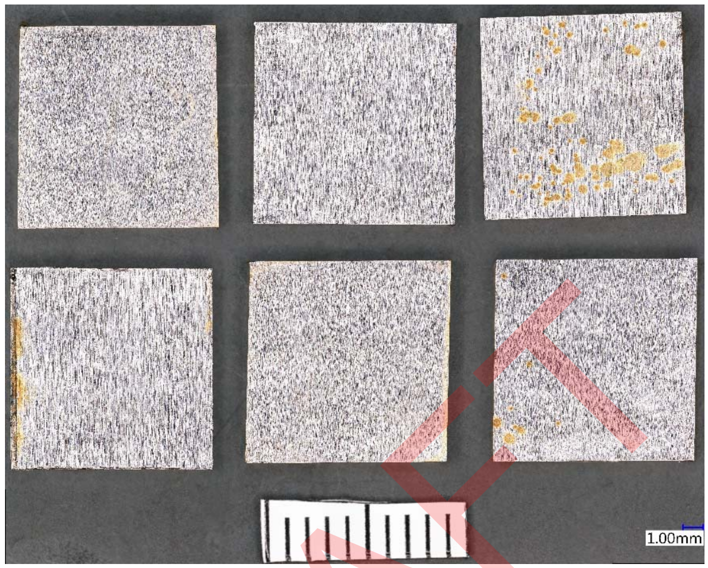

Figure 11. Low magnification morphology of all reference samples after normal corrosion.

2. Water Analysis*

	Units	Sample #1	Sample #2	Sample #3	RDL
pH	pH	7.67	7.52	7.42	N/A
Total Dissolved Solids	mg/L	22	22	14	10
Alkalinity (Total as $CaCO_3$)	mg/L	4.3	2.2	2.1	1.0

RDL – Reportable Detection Limit

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3. Total Metals Analysis by ICPMS of Water Samples*

Metals	Units	Sample #1	Sample #2	Sample #3	RDL
Total Aluminum (Al)	mg/L	0.053	0.050	0.049	0.0050
Total Antimony (Sb)	mg/L	<0.00050	<0.00050	<0.00050	0.00050
Total Arsenic (As)	mg/L	<0.0010	<0.0010	<0.0010	0.0010
Total Barium (Ba)	mg/L	<0.0020	<0.0020	<0.0020	0.0020
Total Beryllium (Be)	mg/L	<0.00050	<0.00050	<0.00050	0.00050
Total Bismuth (Bi)	mg/L	<0.0010	<0.0010	<0.0010	0.0010
Total Boron (B)	mg/L	<0.010	<0.010	<0.010	0.010

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Total Cadmium (Cd)	mg/L	<0.00010	<0.00010	<0.00010	0.00010
Total Calcium (Ca)	mg/L	1.1	1.1	1.0	0.20
Total Chromium (Cr)	mg/L	<0.0050	<0.0050	<0.0050	0.0050
Total Cobalt (Co)	mg/L	<0.00050	<0.00050	<0.00050	0.00050
Total Copper (Cu)	mg/L	<0.0010	<0.0010	<0.0010	0.0010
Total Iron (Fe)	mg/L	<0.10	<0.10	<0.10	0.10
Total Lead (Pb)	mg/L	<0.00050	<0.00050	<0.00050	0.00050
Total Lithium (Li)	mg/L	<0.0050	<0.0050	<0.0050	0.0050
Total Magnesium (Mg)	mg/L	0.35	0.35	0.34	0.050
Total Manganese (Mn)	mg/L	<0.0020	<0.0020	<0.0020	0.0020
Total Molybdenum (Mo)	mg/L	<0.00050	<0.00050	<0.00050	0.00050
Total Nickel (Ni)	mg/L	<0.0010	<0.0010	<0.0010	0.0010
Total Potassium (K)	mg/L	<0.20	<0.20	<0.20	0.20
Total Selenium (Se)	mg/L	<0.0020	<0.0020	<0.0020	0.0020
Total Silicon (Si)	mg/L	0.47	0.46	0.46	0.050
Total Silver (Ag)	mg/L	<0.00010	<0.00010	<0.00010	0.00010
Total Sodium (Na)	mg/L	1.5	1.4	1.4	0.10
Total Strontium (Sr)	mg/L	0.0053	0.0047	0.0043	0.0010
Total Tellurium (Te)	mg/L	<0.0010	<0.0010	<0.0010	0.0010
Total Thallium (Tl)	mg/L	<0.000050	<0.000050	<0.000050	0.000050
Total Tin (Sn)	mg/L	<0.0010	<0.0010	<0.0010	0.0010
Total Titanium (Ti)	mg/L	<0.0050	<0.0050	<0.0050	0.0050
Total Tungsten (W)	mg/L	<0.0010	<0.0010	<0.0010	0.0010
Total Uranium (U)	mg/L	<0.00010	<0.00010	<0.00010	0.00010
Total Vanadium (V)	mg/L	<0.00050	<0.00050	<0.00050	0.00050
Total Zinc (Zn)	mg/L	<0.0050	<0.0050	<0.0050	0.0050
Total Zirconium (Zr)	mg/L	<0.0010	<0.0010	<0.0010	0.0010

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4. Microbiological Corrosion of Algae Samples

	Viable bacteria in samples after 15 days (Range per mL)	
	Sample 1	Sample 2
Low Nutrient Bacteria (LNB)	Weak Positive (~1 to 10)	Mild Positive (~10 to 100)
Iron-Related Bacteria (IRB)	Negative	Negative
Anaerobic Bacteria (ANA)	Weak Positive (~1 to 10)	Weak Positive (~1 to 10)
Acid-Producing Bacteria (APB)	Weak Positive (~1 to 10)	Negative
Sulfate-Reducing Bacteria (SRB)	Negative	Negative

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Appendix G
Backfill Calculations

Nalcor Energy - Bay d'Espoir Penstock 1 - Fill time and soil cover influence

Calculation Cover Sheet

Client:	Nalcor Energy		
Project Title:	Bay d'Espoir Penstock 1 weld repairs		
Discipline:	Mechanical/Civil		
Calculation No:	H352666-00000-240-202-0002 **File No:**		**Number of Sheets:** 27
Description:	This calculation checks penstock fill time. This calculation checks the influence of soil cover at the top half of the penstock on the stresses in the 17 ft diameter sections		
Category of calculation verification required	*tick box*		☑ 1 ☐ 2 ☐ 3 ☐ 4
Prepared by:	Oleg Belashov O.Belashov	**Date:**	28Nov 2016
Print Name >	(Responsible Engineer)		
Preliminary Review by:		**Date:**	28Nov 2016
Print Name >	Michael Pyne		
Can the calculation now be released for work?	☑ Yes ☐ No	**To the Client?**	☑ Yes ☐ No
Checked by: by:		**Date:**	28Nov 2016
Print Name >	Michael Pyne		
Reviewed by:		**Date:**	
Print Name >			
Approved by:		**Date:**	
Print Name >			

General Notes: Internal Rev A-01

Revisions

Rev.	**Date**	**Prepared by**	**Checked by**	**Approved by**	**Description**
A	28Nov 2016	O. Belashov OB	M. Pyne	G.Saunders	

Superseded by Calculation No. **Date:**

Reason voided:

Calculation Descriptions and Assumptions

1. This calculation etimates the penstock fill time.
2. This calculation checks the influence of soil cover at the top half of the penstock on the stresses in the 17 ft diameter sections.
3. The soil on the top of the penstock does not provide any radial restrain for the pipe and is modeled as external pressure applied on top half of the pipe
4. The soil underneath the penstock is modeled as elastic support with the subgrade reaction modulus of soil Ks = $11\frac{MPa}{m} = 40.52\cdot\frac{lbf}{in^3}$
5. Penstock thickness at 17 ft diameter sections is 0.422in according to Ref 7
6. Open channel flow Mannings's Equation is used to determine the cross section area inside the penstock available for air to escape.
7. 100% welded joint efficiency, subject to 100% UT or RT

References

1. Applied Fluid Dynamics Handbook; Robert D.Blevins; 1984
2. ASCE Manuals and Reports on Engineering Practice No. 79, Second edition
3. ASTM A285 2012
4. F-105-C-2
5. F-106-C-7
6. F-106-C-11
7. PENSTOCK NO.1 BAY D'ESPOIR HYDROELECTRICDEVELOPMENTCRACK; INVESTIGATION ANDREPAIR REPORT; by Kleinschmidt; June 2016

1) Filling time and pipe area available for air to escape

Input parameters

$EL_{HWL} := 593ft$ Head pond water elevation, Ref 4

$EL_{sill} := 541ft$ Intake gate sill elevation, Ref 4

$w_g := 17ft$ Intake gate clear width

$EL_{ST} := 291.58ft$ Surge tank bottom elevation

$D_{ST} := 13ft + 6in$ Assumed surge tank inlet pipe diameter, no info on the surge tank is available

$n := 13$ Number of penstock sections

$i := 0 .. n - 1$

Penstock geometry, Ref 6

i + 1 =	Section length $L_i :=$	Section diameter $D_i :=$
1	231.68ft	17ft + 0in
2	320.64ft	17ft + 0in
3	250.01ft	17ft + 0in
4	452.05ft	17ft + 0in
5	361.39ft	15ft + 3in
6	351.28ft	15ft + 3in
7	304.72ft	15ft + 3in
8	379.75ft	13ft + 6in
9	476.41ft	13ft + 6in
10	523.51ft	13ft + 6in
11	122.83ft	13ft + 6in
12	63.89ft	13ft + 6in
13	45.10ft	13ft + 6in

$G_o := 0.5in, 1in .. 6in$ Range of intake gate openings for consideration

Filling time as function of gate opening

$\sum L = 1184 \cdot m$ — Total penstock length

$H := EL_{HWL} - EL_{sill} = 52 \cdot ft$ — Head on the intake gate sill

$V_p := \sum_i \left[\frac{\pi \cdot (D_i)^2}{4} \cdot L_i\right] = 19856\,m^3$ — Penstock volume

$L_{ST} := EL_{HWL} - EL_{ST} = 301.42 \cdot ft$ — Surge tank pipe to be filled

$V_{ST} := \frac{\pi \cdot D_{ST}{}^2}{4} \cdot L_{ST} = 1222\,m^3$ — Surge tank pipe volume

$V_{tot} := V_p + V_{ST} = 21078\,m^3$ — Total volume to be filled, excluding spiral case since no info is provided.

$Q_g(G_o) := \frac{0.61}{\left(1 + 0.61 \cdot \frac{G_o}{H}\right)^{0.5}} \cdot w_g \cdot G_o \cdot \sqrt{(2 \cdot g \cdot H)}$ — Flow rate in volume/time units as function of intake gate opening, Ref 1

$t(G_o) := \frac{V_{tot}}{Q_g(G_o)}$ — Filling time as function of gate opening

Pipe cross section area available for air to escape as function of gate opening

The calculation is performed using open channel flow Manning's Equation

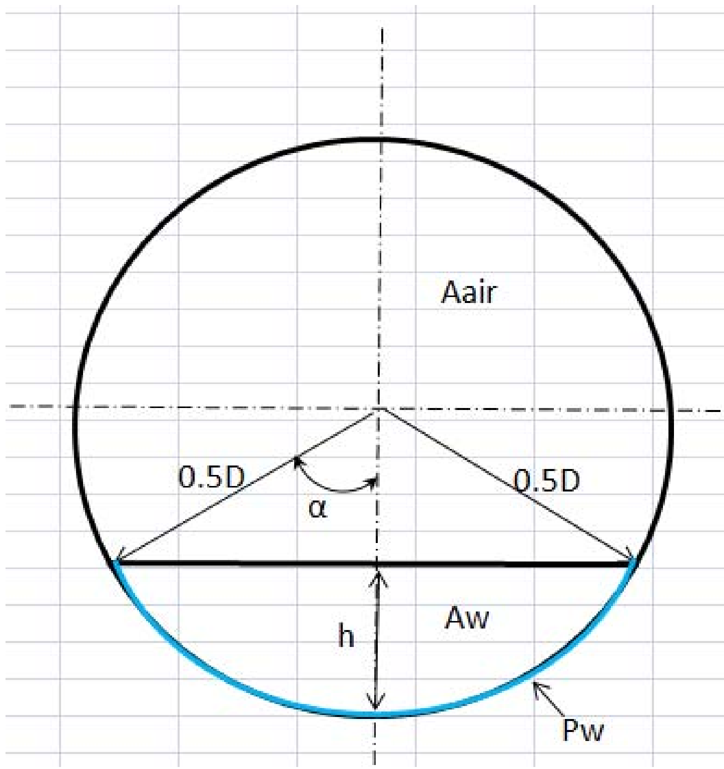


Figure 1: Open channel flow in the penstock

$S_p := \tan(0.25deg)$ Penstock slope, Manning's Equation works with very small pipe slope but the slope cannot be zero

$n := 0.012$ Manning's roughness coefficient for steel pipe

$D_{min} := \min(D) = 13.5 \cdot ft$ Min diameter in the penstock

$A_p := \frac{\pi \cdot D_{min}^2}{4} = 13.3\,m^2$ Penstock cross section area at the minimum diameter

$\alpha(h) := acos\left(\frac{0.5 \cdot D_{min} - h}{0.5 \cdot D_{min}}\right)$ α (Figure 1) as function of h

$A_w(h) := \frac{D_{min}^2}{4} \cdot (\alpha(h) - \sin(\alpha(h)) \cdot \cos(\alpha(h)))$ Flow area as function of h

$P_w(h) := \alpha(h) \cdot D_{min}$ Wetted perimeter

$R_h(h) := \dfrac{A_w(h)}{P_w(h)}$ Hydraulic radius

$AR(h) := A_w(h) \cdot R_h(h)^{\frac{2}{3}}$ $A \cdot R^{\frac{2}{3}}$ term from Manning's equation

$Q_p(h) := \dfrac{ft^3}{s} \cdot \left[\left(\dfrac{1.49}{n} \right) \cdot \left(\dfrac{1}{ft^2} \cdot \dfrac{1}{ft^{\frac{2}{3}}} \right) \cdot AR(h) \cdot \sqrt{S_p} \right]$ Manning's equation for volume flow in open channel

$h := 1m$ Initial guess for solver

Given

$Q_p(h) = Q$

$h(Q) := (\mathrm{Find}(h))$ Solve for h (Figure 1)

$h(G_o) := h(Q_g(G_o))$ Express h as function of gate opening

$A_{air}(G_o) := 1 - \dfrac{A_w(h(G_o))}{A_p}$ Area available for air to escape in % of total pipe area as function of intake gate opening

Summary

Gate opening $\frac{G_o}{in}$	Flow rate $\frac{Q_g(G_o)}{\frac{m^3}{s}}$	Fill time $\frac{t(G_o)}{hr}$	Flow area height $\frac{h(G_o)}{m}$	Flow area $\frac{A_w(h(G_o))}{m^2}$	Air area $\frac{A_{air}(G_o)}{\%}$
0.5	0.71	8.27	0.28	0.40	97.00
1.0	1.41	4.14	0.39	0.65	95.14
1.5	2.12	2.76	0.48	0.86	93.55
2.0	2.83	2.07	0.55	1.05	92.11
2.5	3.53	1.66	0.61	1.23	90.78
3.0	4.24	1.38	0.67	1.39	89.52
3.5	4.95	1.18	0.72	1.55	88.32
4.0	5.65	1.04	0.77	1.71	87.17
4.5	6.36	0.92	0.81	1.85	86.06
5.0	7.06	0.83	0.85	2.00	84.99
5.5	7.76	0.75	0.90	2.14	83.94
6.0	8.47	0.69	0.93	2.27	82.92

$A_p = 13.3\,m^2$

There is plenty of room for air to escape for all the considered intake gate openings

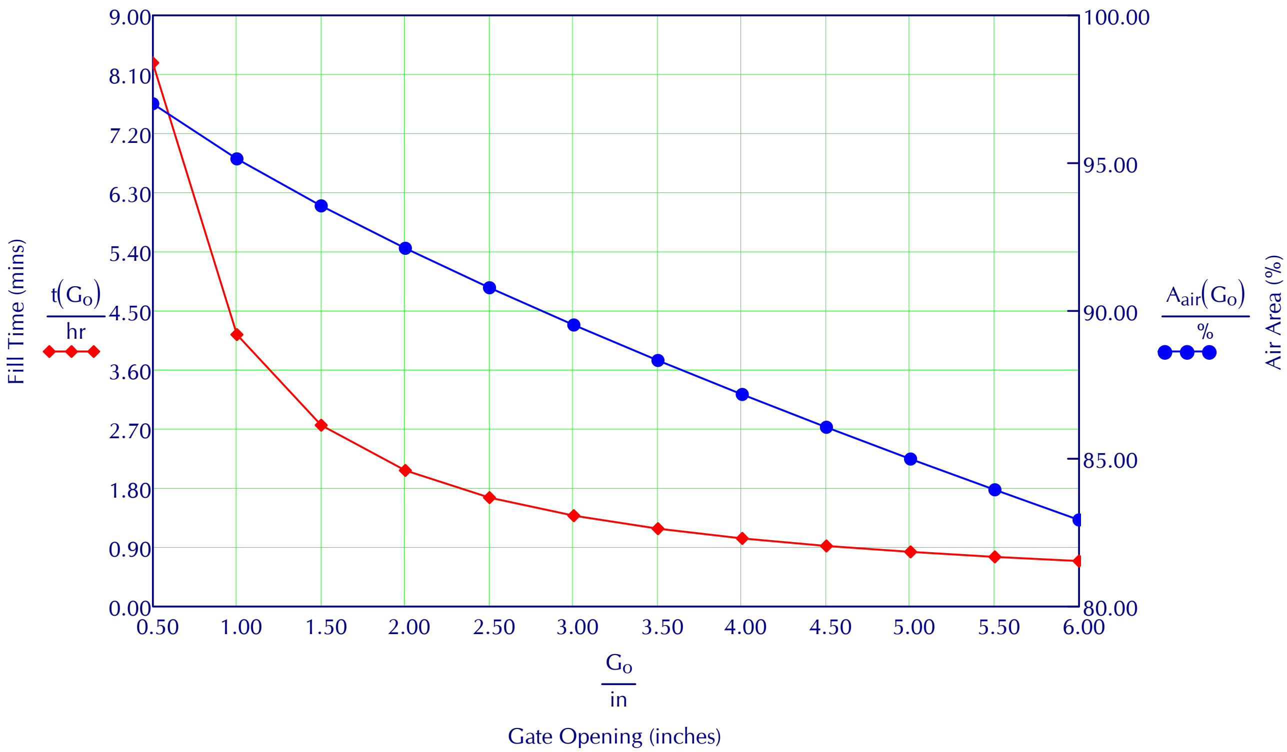


Figure 2: Fill Time and Air Area as Function of Gate Opening

2) Finite Element Analyses of excavation

FE model description

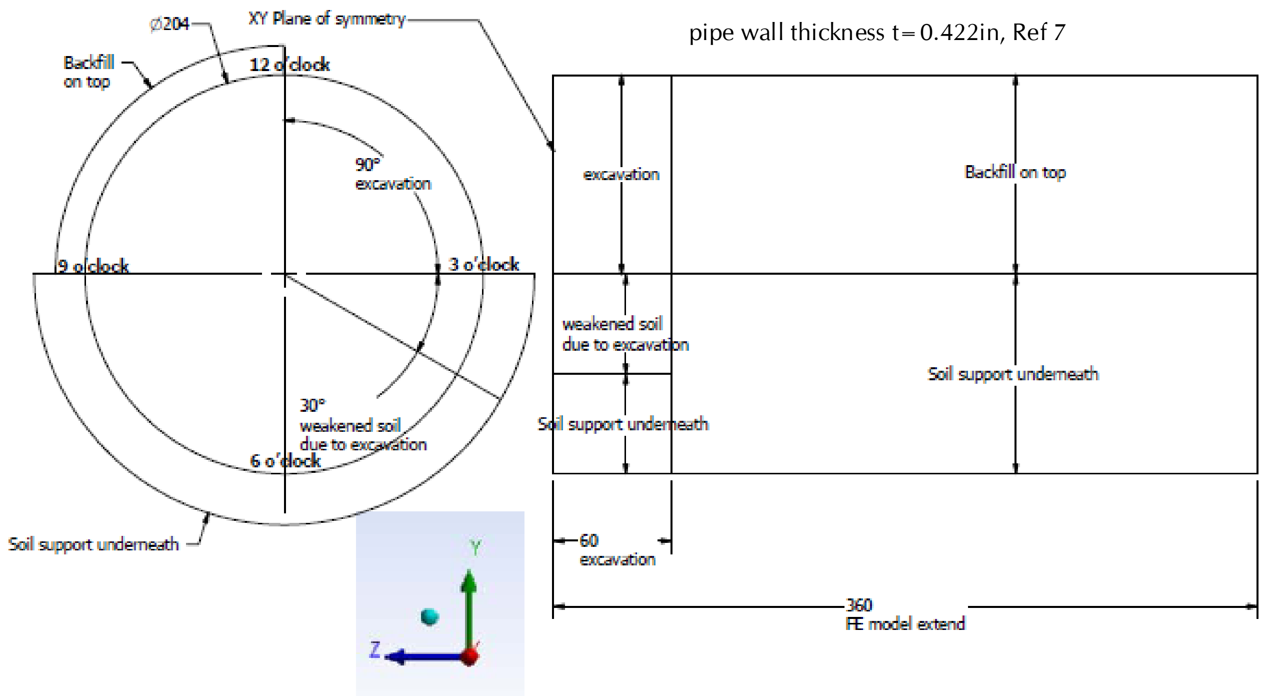


Figure 3: Finite element model dimensions, inches. 60ft long pipe with soil support at the bottom half. Top soil pressure on the top half. Excavation extend from 12 to 3 o'clock 10 ft long. 30deg from 3 o'clock 10 ft long is considered weakened soil (very low Ks value) and is assumed to be part of the excavation. Middle of the excavation is a plane of symmetry thus only half of 60 ft pipe was modeled

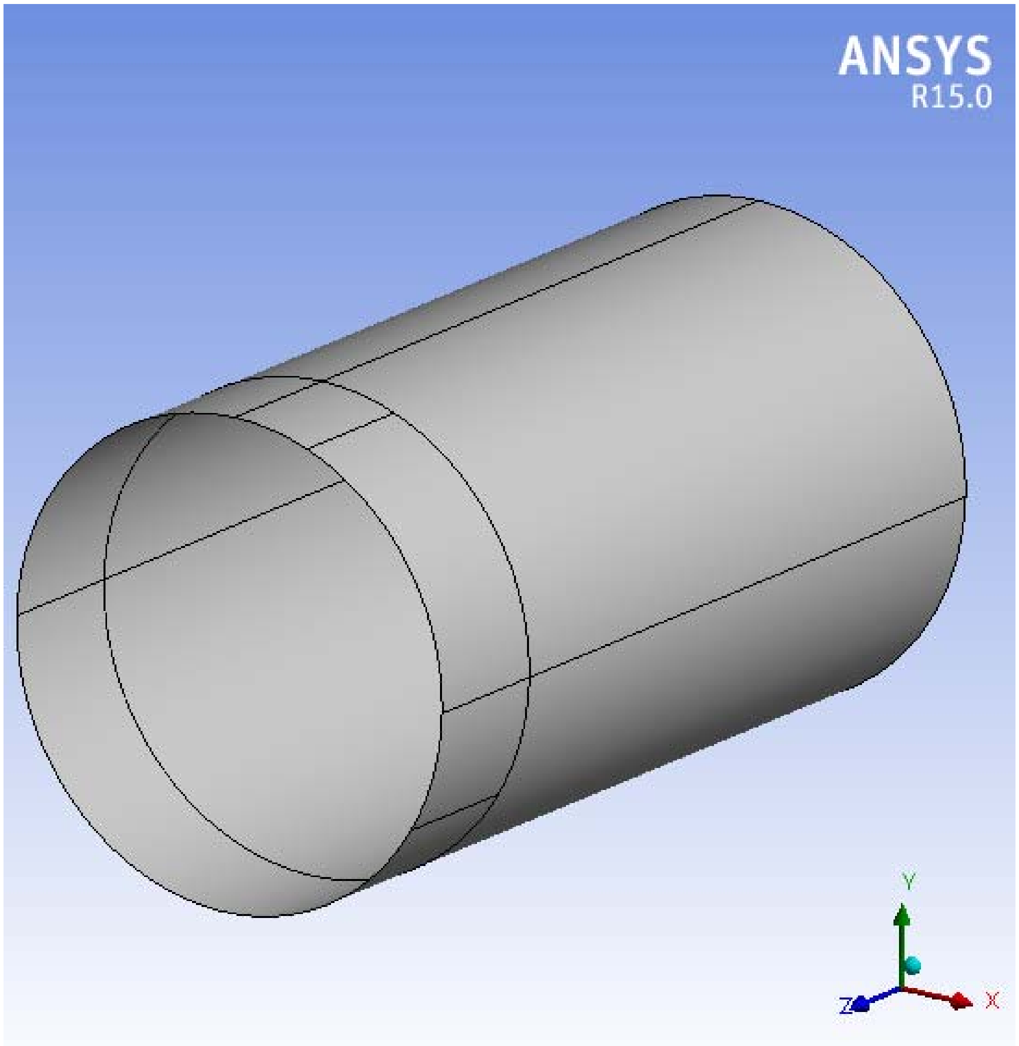


Figure 4: Finite element model. Ansys R15.0 software was used.

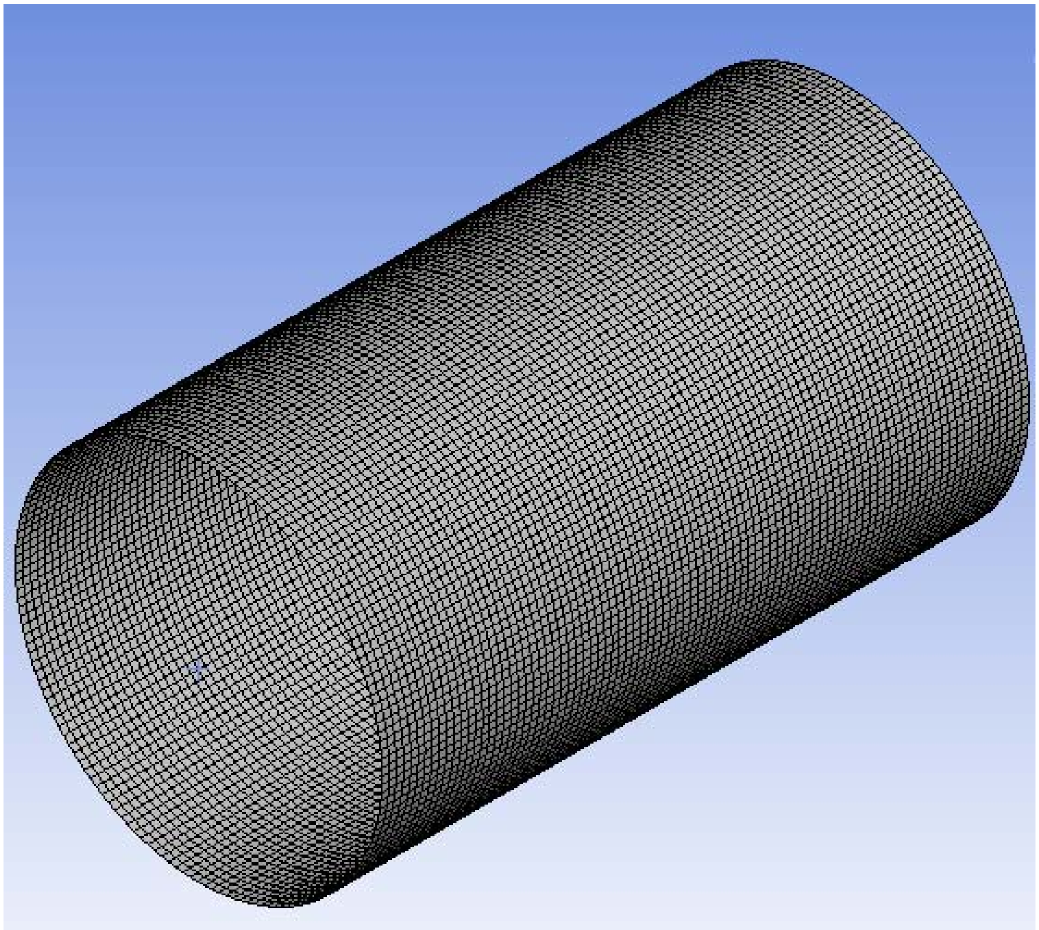
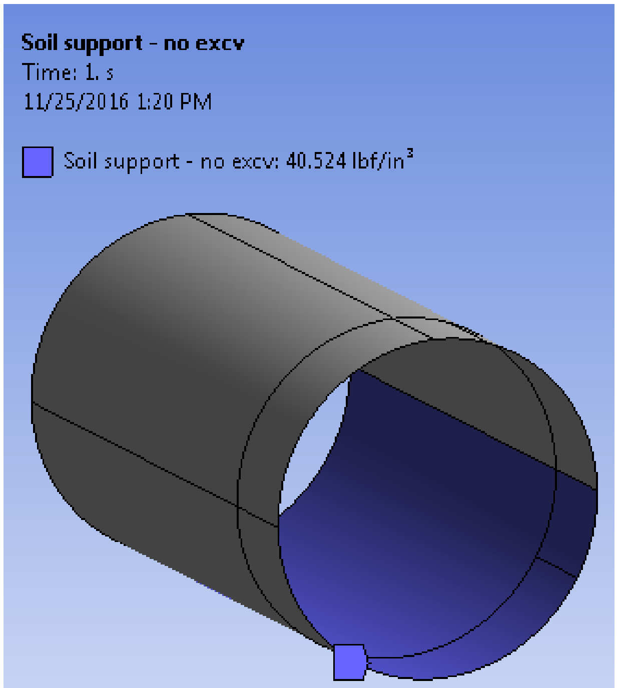
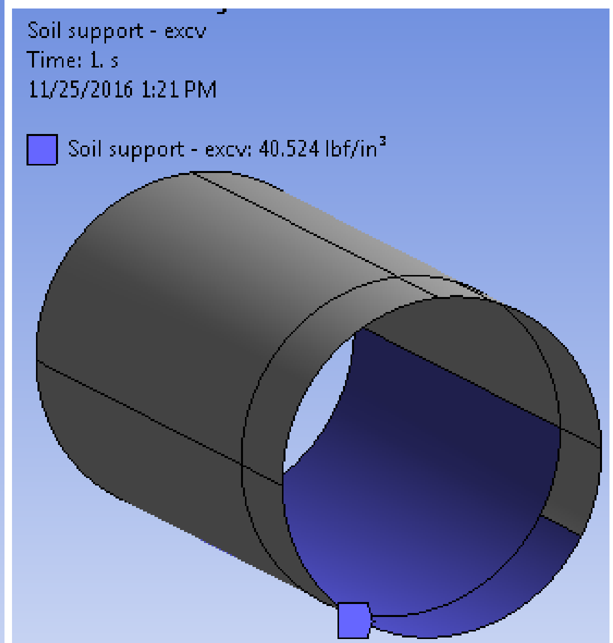


Figure 5: Finite element mesh. The model was meshed with 4-node SHELL181 elements. E = 200GPa, v = 0.3, ρ = 7850kg/m^3

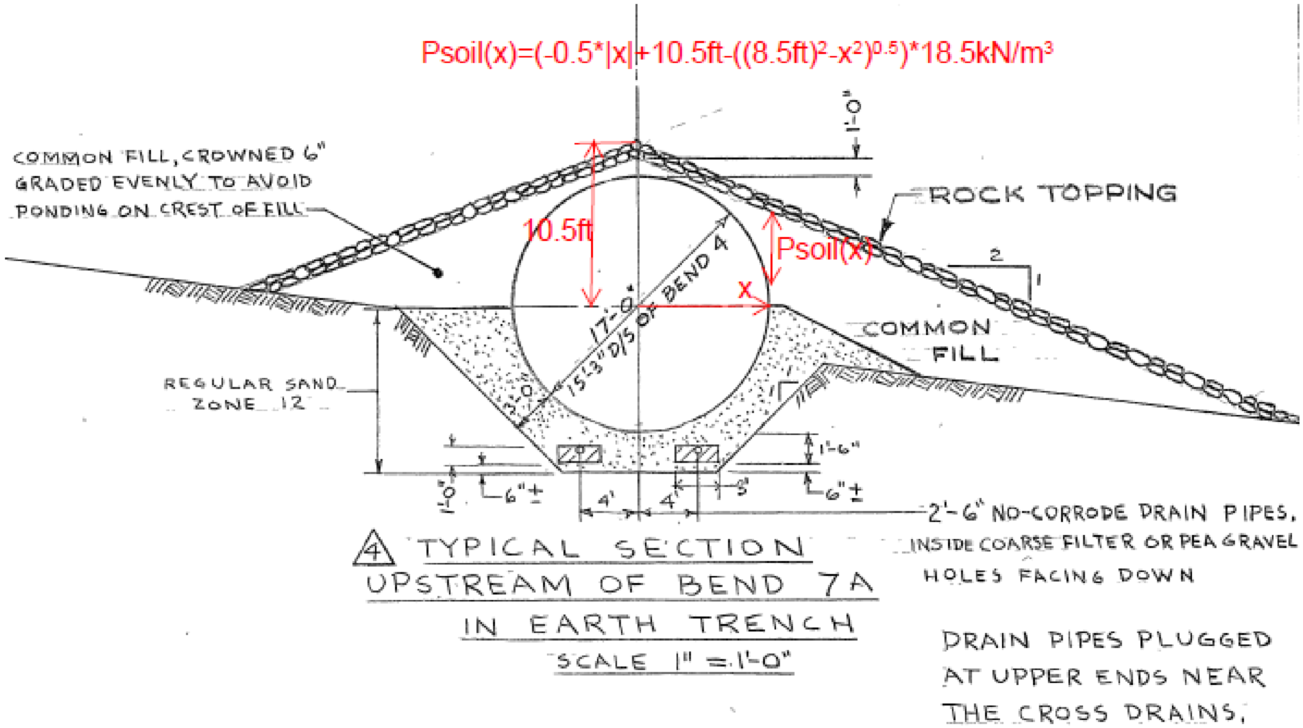


No excavation



With excavation

Figure 6: Subgrade reaction modulus of soil $Ks = 11\frac{MPa}{m} = 40.52\cdot\frac{lbf}{in^3}$ was applied at the bottom half.



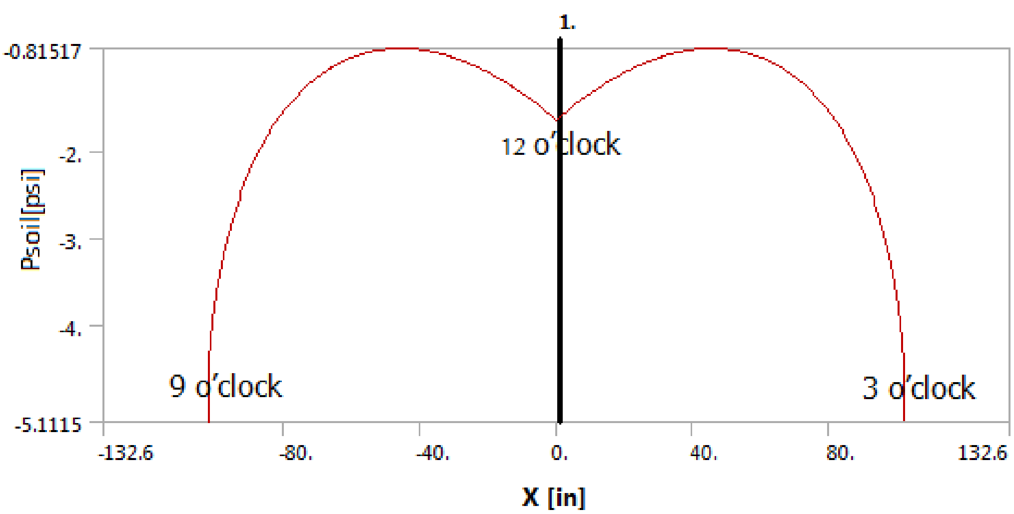
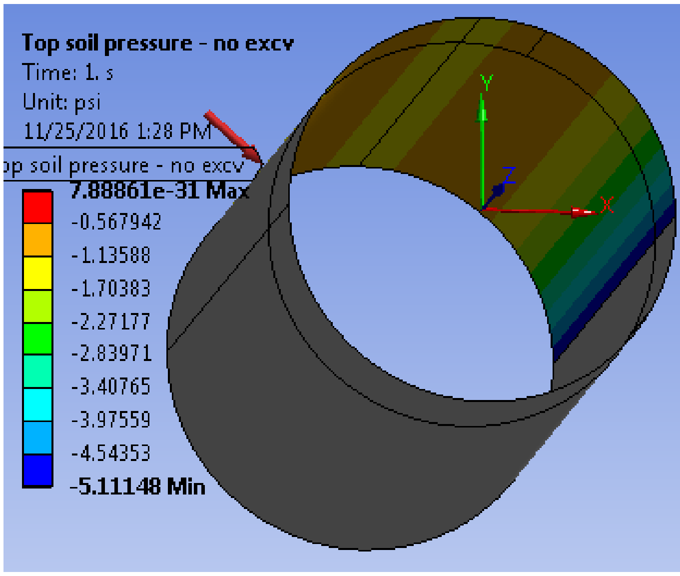
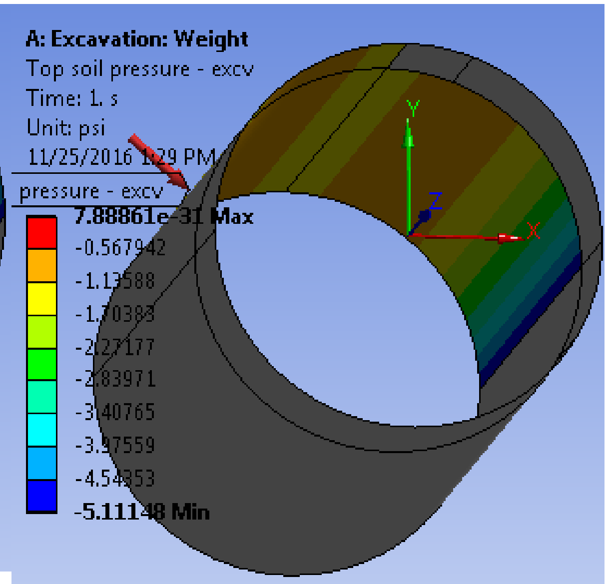


Figure 7:Pressure from the soil on top of pipe. The soil density was assumed at $18.5\frac{kN}{m^3} = 0.0682\cdot\frac{lbf}{in^3}$.



No excavation



With excavation

Figure 8:Pressure from the soil on top of pipe applied as external pressure.

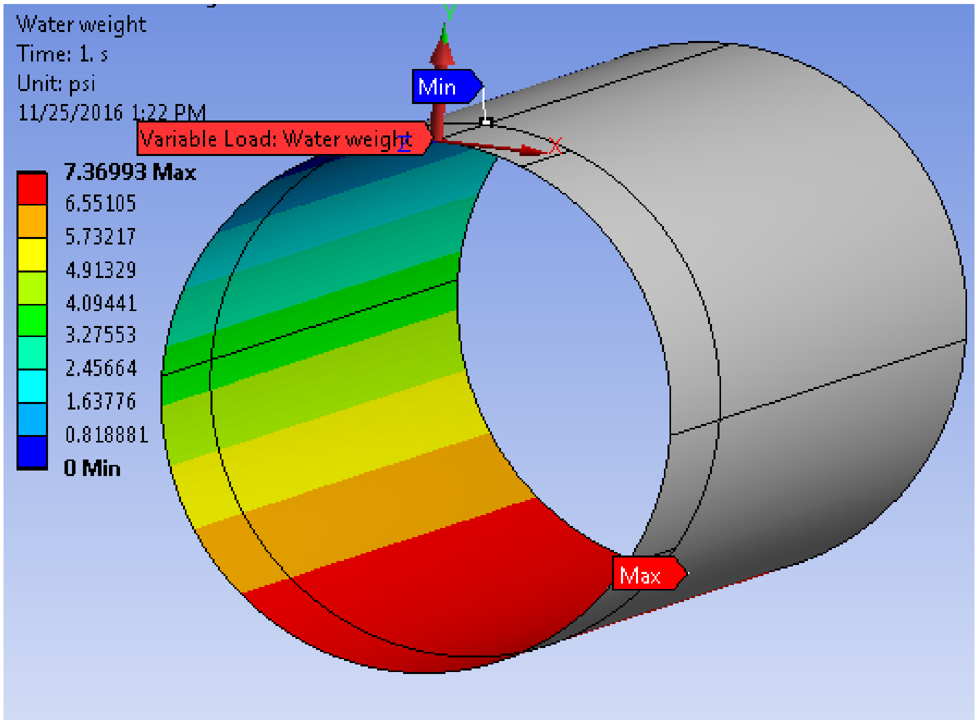


Figure 9: Water weight applied as hydrostatic internal pressure with 0 psi at the top of the pipe

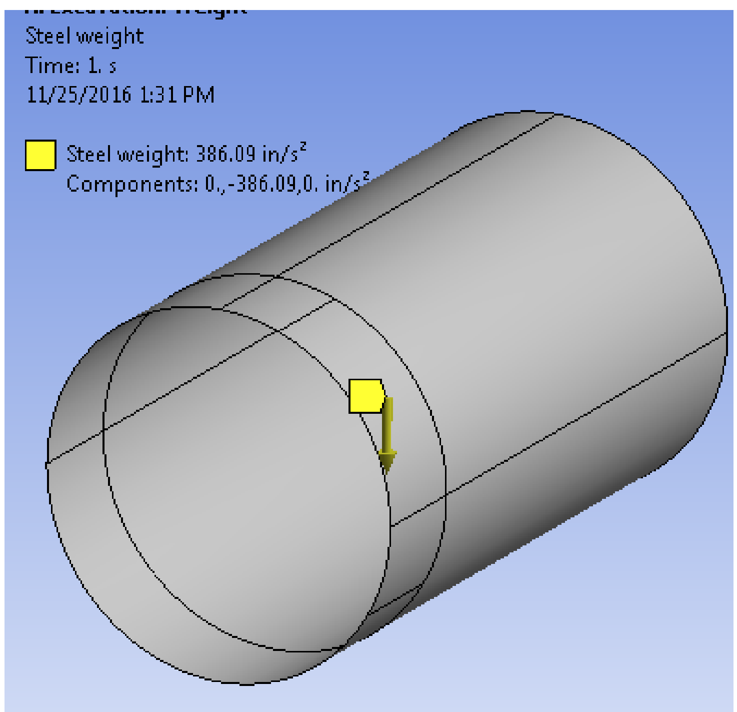


Figure 10: Steel weight

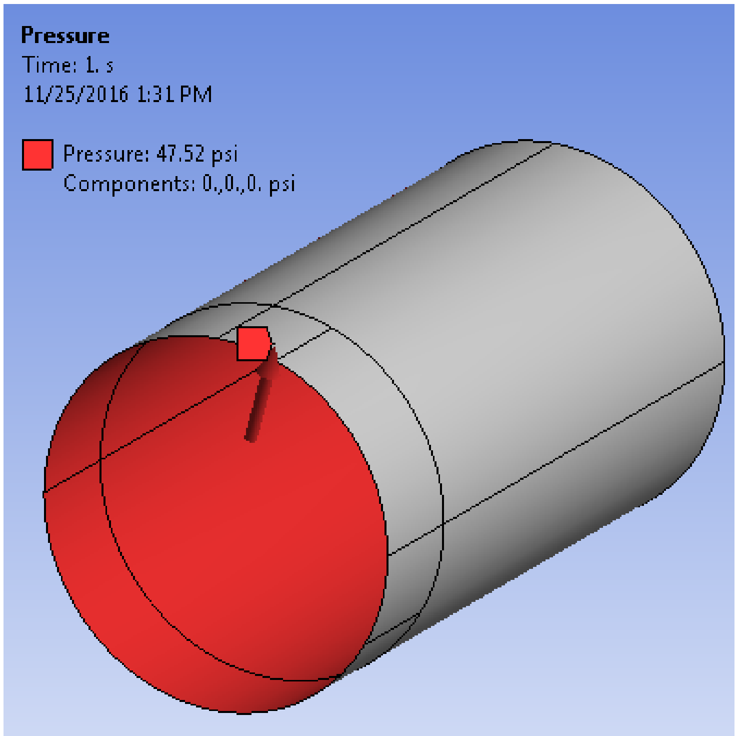


Figure 11: Internal pressure 47.52 psi including pressure surge from pressure line of Ref 5.

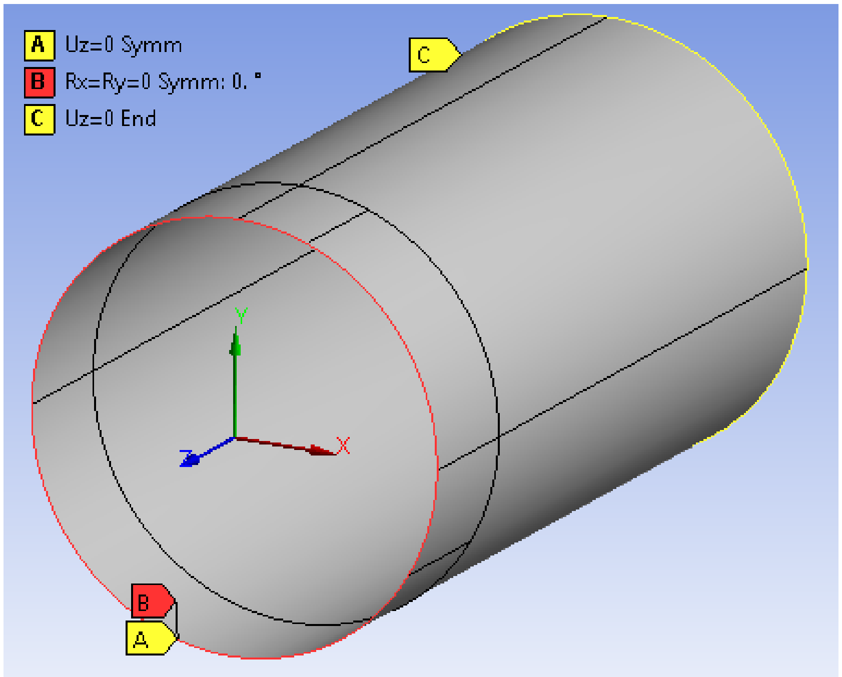


Figure 12: Constrains: Uz = Rx = Ry = 0 at the XY symmetry plane. Uz = 0 at the end.

Results

Three loading scenarios were considered:
LS1 = Water Weight + Steel Weight + Internal Pressure. No soil on top of the penstock, no excavation
LS2 = Water Weight + Steel Weight + Top Soil Weight + Internal Pressure. No excavation
LS3 = Water Weight + Steel Weight + Top Soil Weight + Internal Pressure. With excavation

$F_{uA285} := 55ksi$ Tensile stress $F_{uA285} = 379 \cdot MPa$ Assume Grade C, Ref 3

$F_{yA285} := 30ksi$ Yield stress $F_{yA285} = 207 \cdot MPa$

$Si_{A285} := \min\left(\frac{F_{uA285}}{2.4}, \frac{F_{yA285}}{1.5}\right) = 20000 \cdot psi$ Basic allowable stress intensity according to Ref 2 for continuous plate

$Sa_{pA285} := 1.0 \cdot Si_{A285} = 20000 \cdot psi$ Allowable for primary general membrane stress. Ref 2, for continuous plate

$Sa_{lA285l} := 1.5 \cdot Si_{A285} = 30000 \cdot psi$ Allowable for local membrane stress + pramary bending. Ref 2, for continuous plate

$Sa_{QA285} := \min\left(3 \cdot Si_{A285}, F_{uA285}\right) = 55000 \cdot psi$ Allowable for secondary stress = Local membrane stress + local shell bending. Ref1, for continuous plate

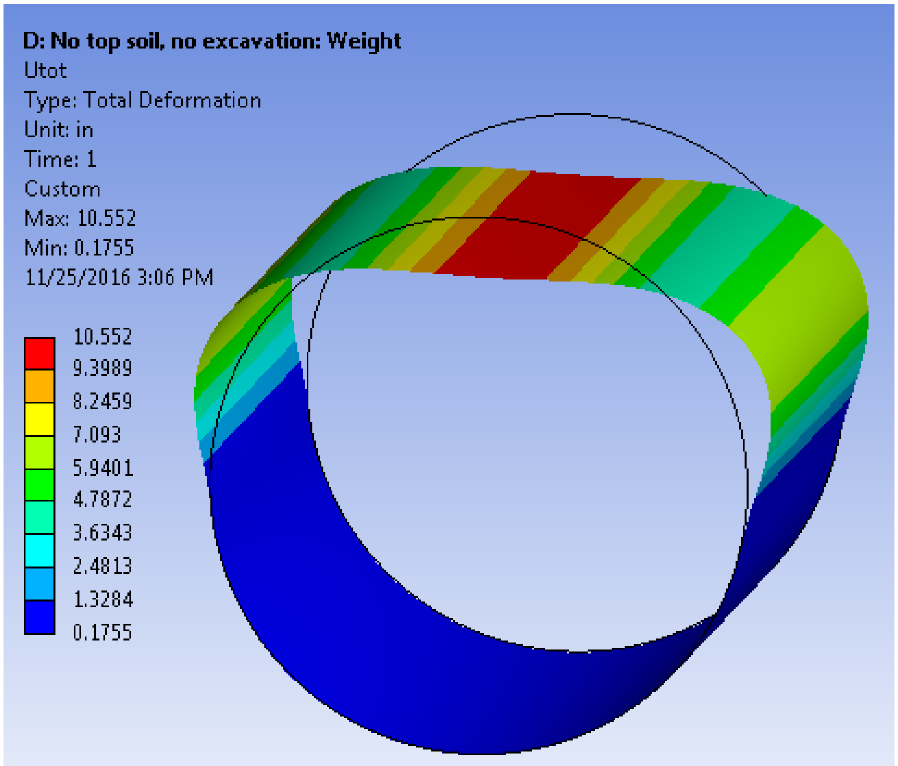


Figure 13: Deformation due LS1 without Internal Pressure.

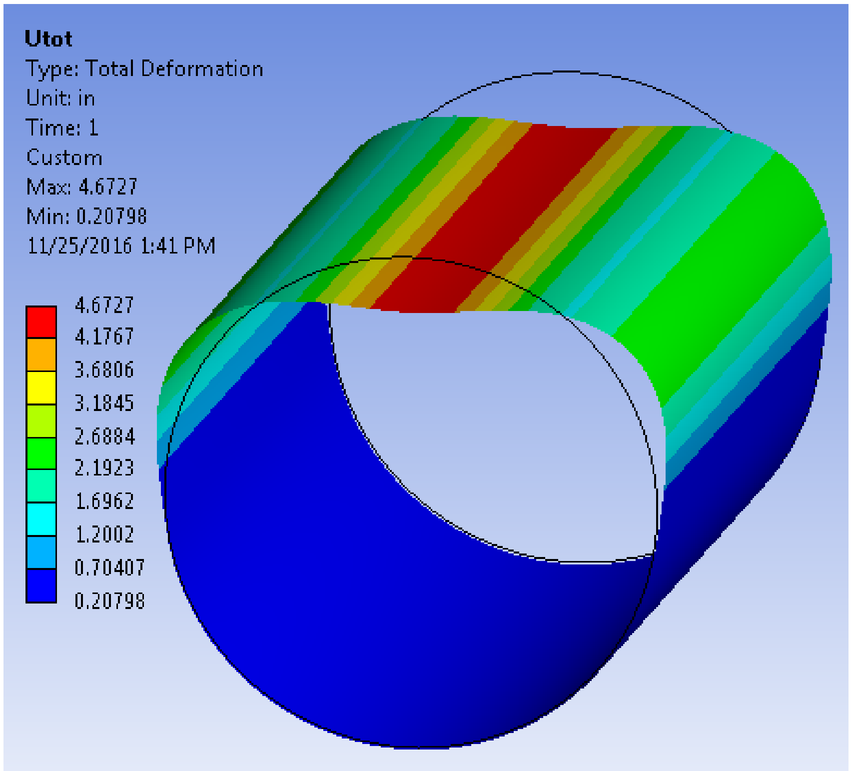


Figure 14: Deformation due LS2 without Internal Pressure.

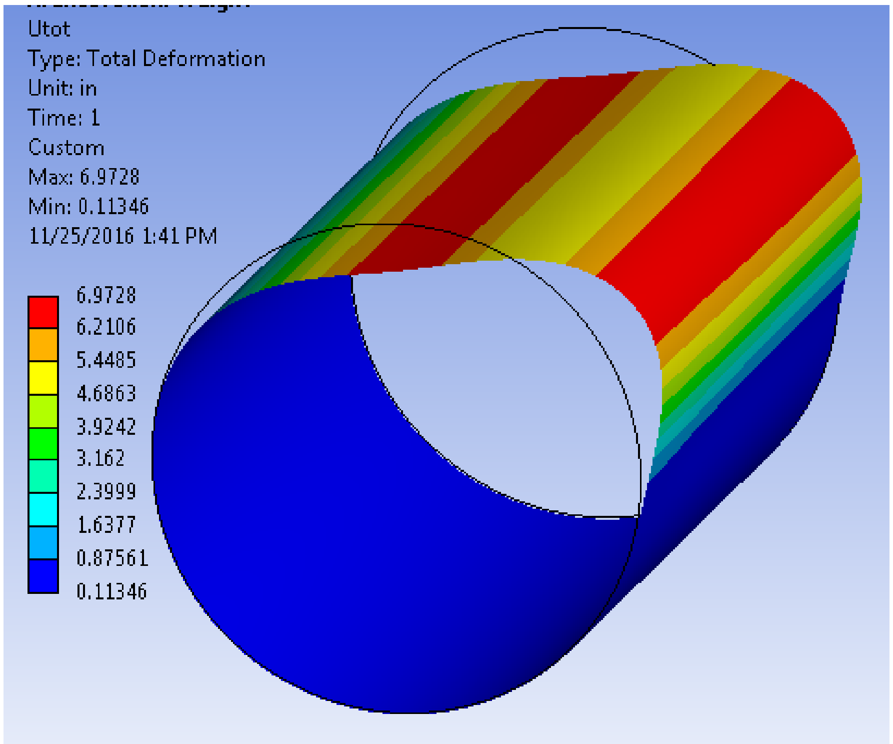


Figure 15: Deformation due LS3 <u>without</u> Internal Pressure.

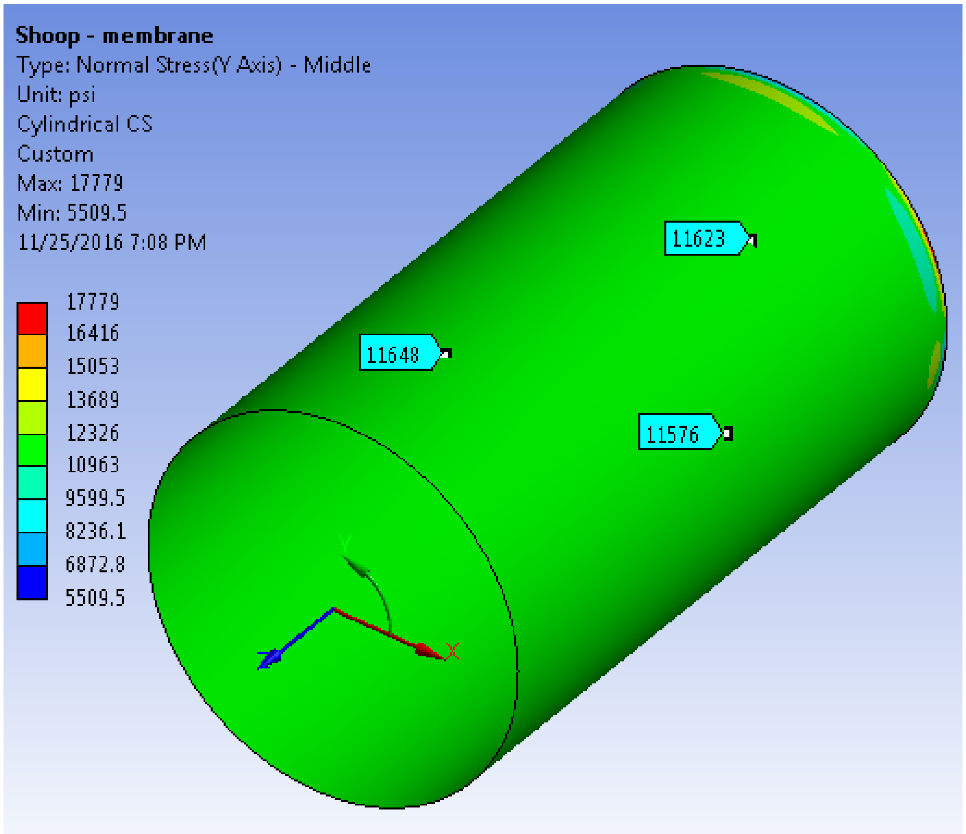


Figure 16: LS1 - Membrane hoop stress. Allowable for continuous plate $Sa_{pA285} = 20000 \cdot psi$. Ignore minor spikes at the boundary. No overstress.

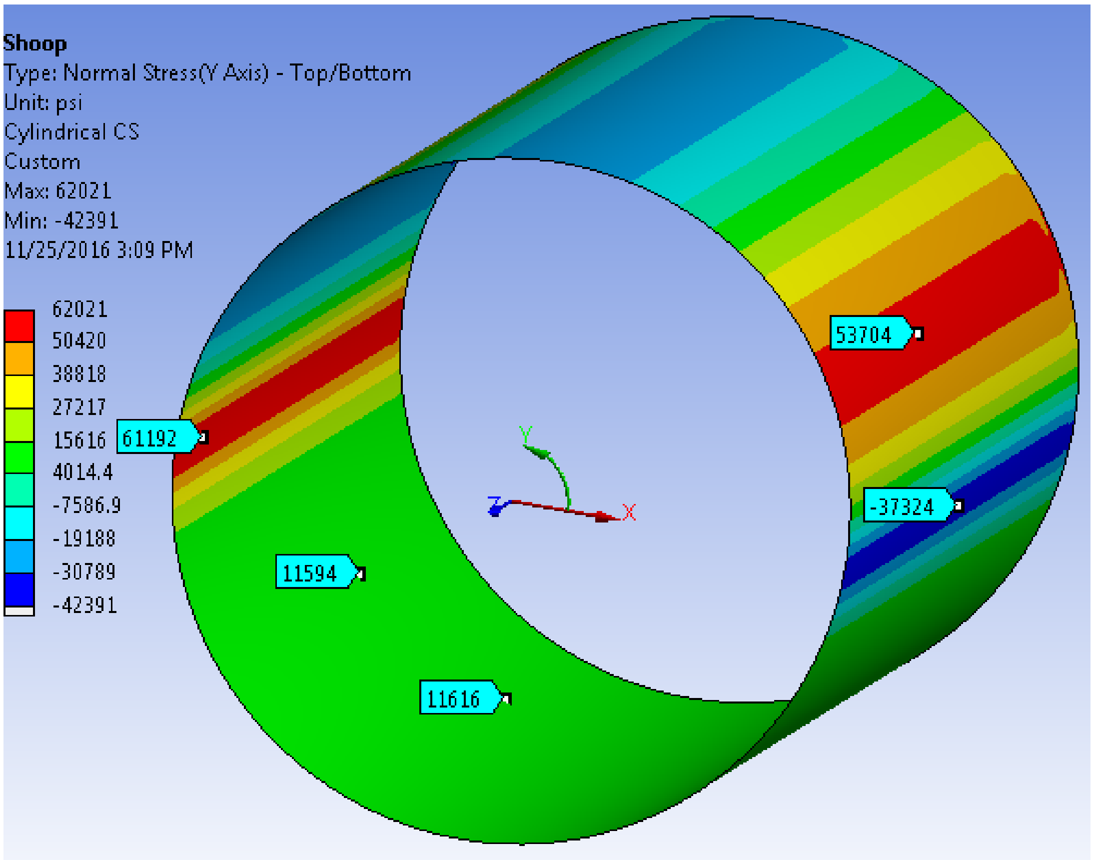


Figure 17: LS1 - Total hoop stress. Allowable for continuous plate $Sa_{lA285l} = 30000 \cdot psi$. 100% overstress, more if longitudinal welded joint efficiency at 3 and 9 o'clock is taken into account.

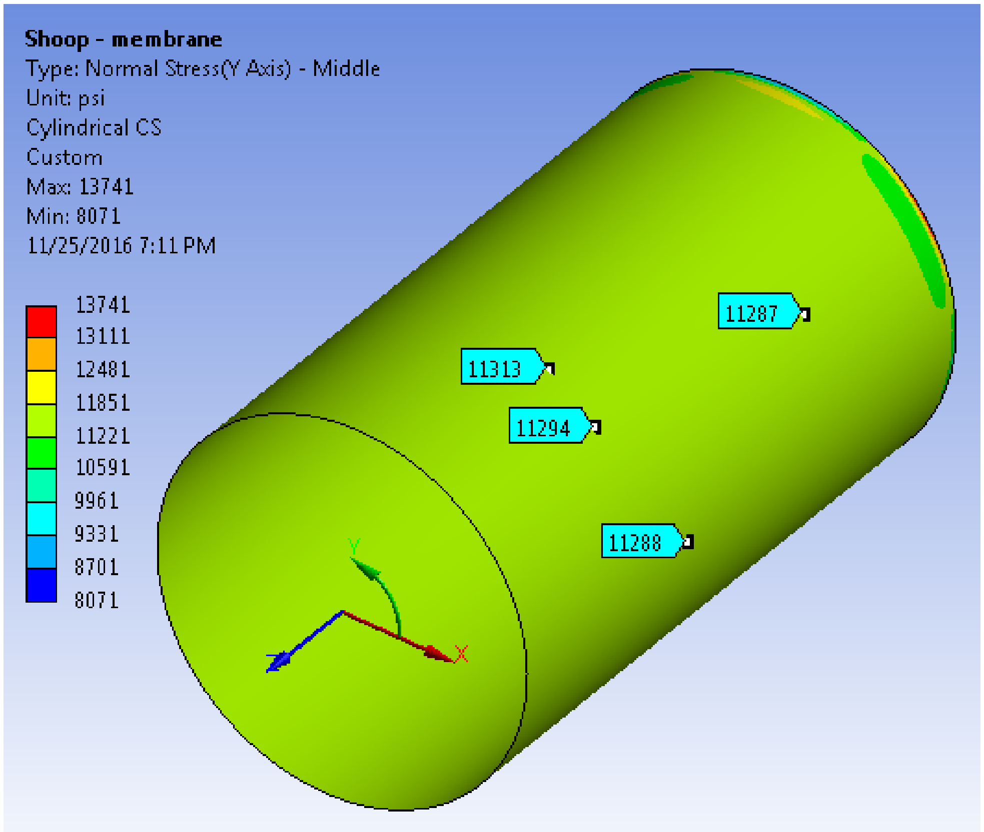


Figure 18: LS2 - Membrane hoop stress. Allowable for continuous plate $Sa_{pA285} = 20000 \cdot psi$. Ignore minor spikes at the boundary. No overstress.

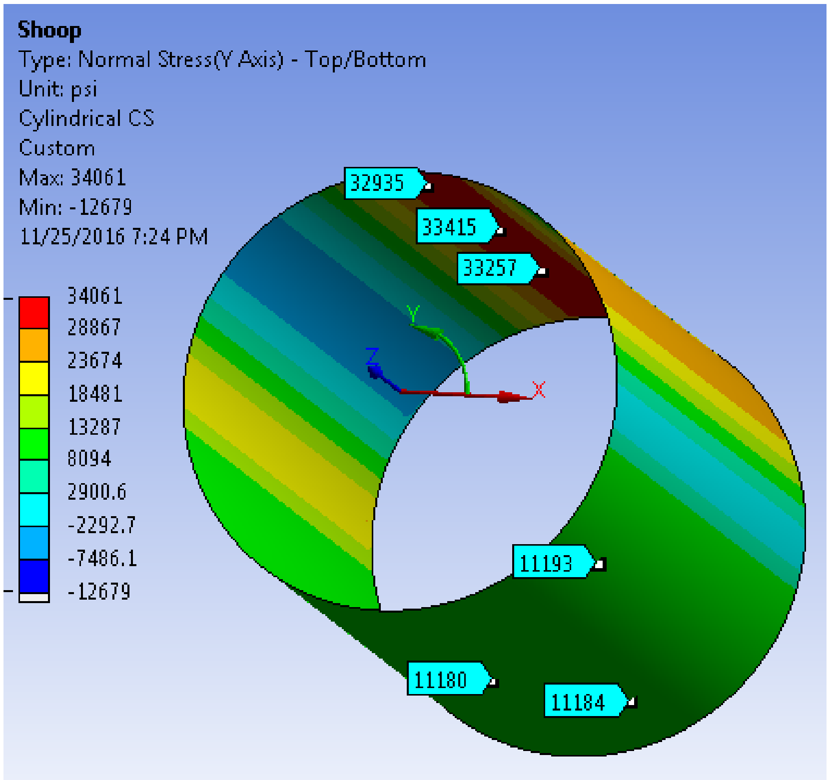


Figure 19: LS2 - Total hoop stress. Allowable for continuous plate $Sa_{lA285l} = 30000 \cdot psi$. 12% overstress.

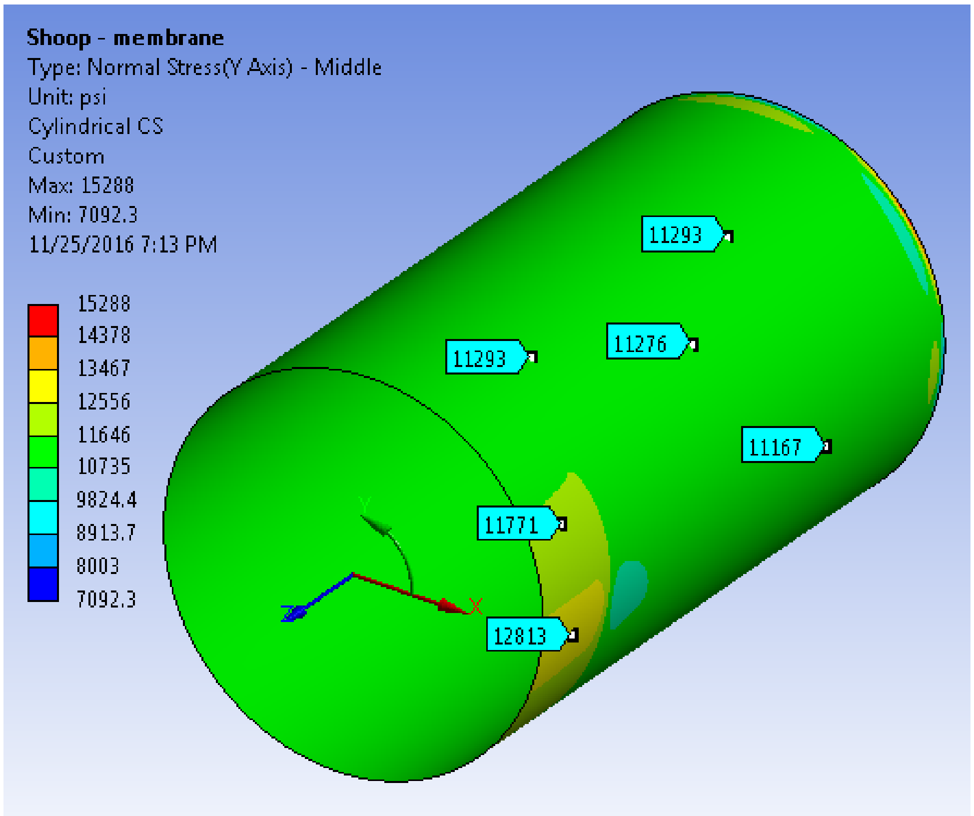


Figure 20: LS3 - Membrane hoop stress. Allowable for continuous plate $Sa_{pA285} = 20000 \cdot psi$. Ignore minor spikes at the boundary. No overstress.

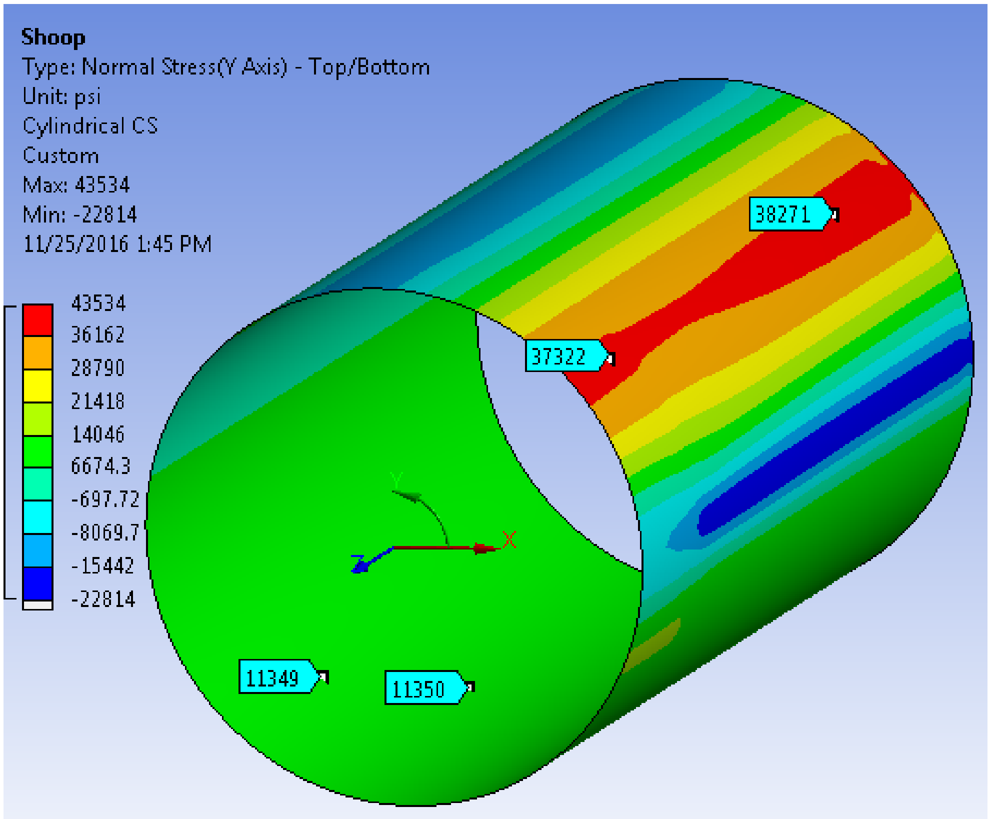


Figure 21: LS3 - Total hoop stress. Allowable for continuous plate $Sa_{IA285I} = 30000 \cdot psi$. 45% overstress, more if longitudinal welded joint efficiency at 3 o'clock is taken into account.

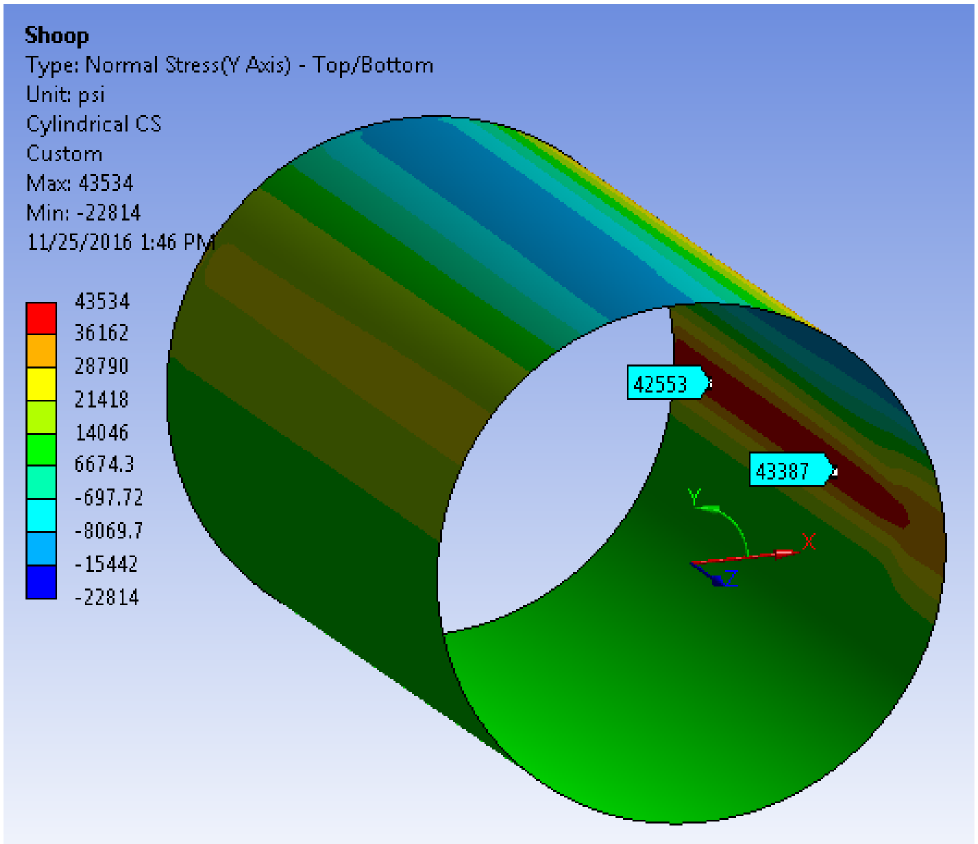
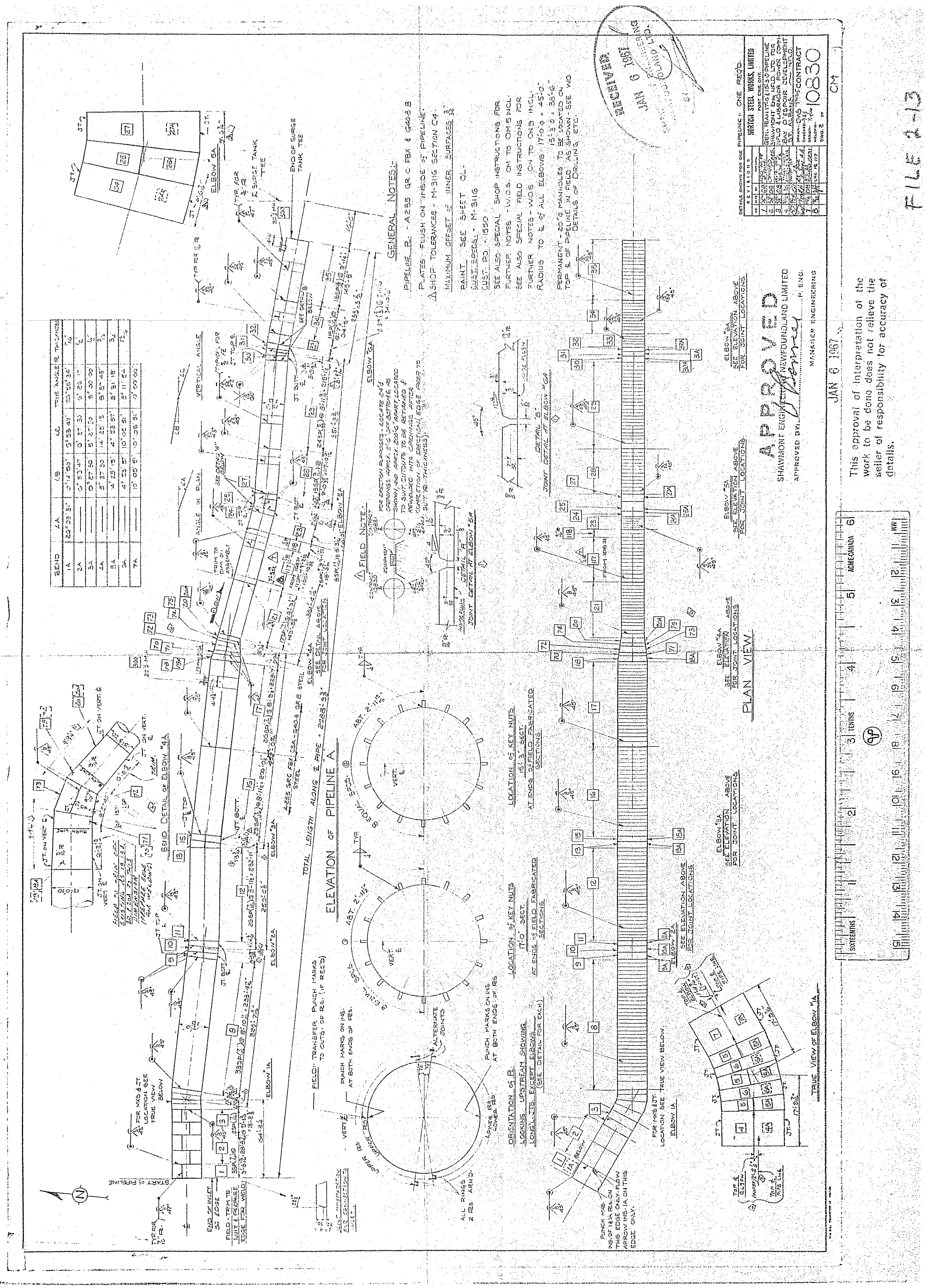


Figure 22: LS3 - Total hoop stress. Allowable for continuous plate $Sa_{|A285|} = 30000 \cdot psi$. 45% overstress, more if longitudinal welded joint efficiency at 3 o'clock is taken into account.

Conclusions and recommendations

Soil cover on top of the penstock plays an important role in reducing the stresses caused by the water + steel weight.
Excavation causes 100% hoop stress increase (from 22,000psi to 43,500 psi) at 3 o'clock.
It is recommended to restore the excavated sections to their original state (as per Ref 5) prior to filling the penstock.
It is recommended to construct a more comprehensive FE model taking into account soil-steel frictions to study the influence of the soil cover at the top half of the pipe on the stresses in the 17ft diameter penstock sections.

Appendix H
NL Hydro Drawing No. 10830-2 Penstock No. 1 Intake to Surge Tank


ELEVATION OF PIPELINE A
PLAN VIEW
GENERAL NOTES:-
BEND DETAIL OF ELBOW #4A
TRUE VIEW OF ELBOW #1A
APPROVED
SHAWINIGAN ENGINEERING NEWFOUNDLAND LIMITED
JAN 6 1967
This approval of interpretation of the work to be done does not relieve the seller of responsibility for accuracy of details.
RECEIVED
10830
FILE 2-13

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Newfoundland & Labrador Hydro
HYDRO GENERATION
EQUIPMENT INVESTIGATION REPORT

HELP

Standing Instruction No. 62
Forced Outage Reporting & Investigation

Location:	Upper Salmon	**Unit No:**	1	**Business Unit:**	1284	**Outage No.:**	2017-07

Equipment Name: Upper Salmon Generating Unit

Brief Description of Event:

Unit was shutdown due to an unusual smell emitting from the unit.

Investigation Assigned to: Dan King

Date of Event: 2017/03/06 **Date of Investigation:** 2017/03/08

Parent Work Order Number: 1245721 **Status of Investigation:** Complete

Dan King	Alvin Crant
Signature of Investigator	Signature of Approver

Detailed Description of Event:

The Operator in the plant observed an unusaul smell emitting from the Generator area and noticibly on Generator floor and on the deck near the office area. Due to a previous issue and similar smell that occurred when the rotor keys had caused damage to unit shrouds the unit was removed from service and an inspection of the Rotor was undertaken. During the inspection four Rotor keys were found loose and had to be re-welded back in place. Several top and bottom shrouds were removed and the rotor was inspected and no signs of damage observed other that the broken welds on the identified keys..

BASIC / ROOT CAUSES:

1. Basic/Root Cause Category: JF - EXCESSIVE WEAR AND TEAR

Basic or Root Cause: N/A

Explanation:

This unit has been subject to the welding on Rotor keys breaking or cracking in the past and have been inspected and welded. The OEM has been consulted on several occasions and have inspected the fretting and corrosiion issues with the unit and have recommended that some major work be completed on the Rotor in 2018 .

2. Basic/Root Cause Category:

Basic or Root Cause:

Explanation:

3. Basic/Root Cause Category:

Basic or Root Cause:

Explanation:

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HYDRO GENERATION
EQUIPMENT INVESTIGATION REPORT

HELP
Standing Instruction No. 62
Forced Outage Reporting & Investigation

Location:	Upper Salmon	Unit No:	1	Business Unit:	1284	Outage No.:	2017-07

Equipment Name: Upper Salmon Generating Unit

Brief Description of Event:

Unit was shutdown due to an unusual smell emitting from the unit.

BASIC / ROOT CAUSES Cont'd:

4. Basic/Root Cause Category:

Basic or Root Cause:

Explanation:

5. Basic/Root Cause Category:

Basic or Root Cause:

Explanation:

6. Basic/Root Cause Category:

Basic or Root Cause:

Explanation:

7. Basic/Root Cause Category:

Basic or Root Cause:

Explanation:

8. Basic/Root Cause Category:

Basic or Root Cause:

Explanation:

Printed on: 3/14/2019

Newfoundland & Labrador Hydro
HYDRO GENERATION
EQUIPMENT INVESTIGATION REPORT

HELP

Standing Instruction No. 62
Forced Outage Reporting & Investigation

Location:	Upper Salmon	Unit No:	1	Business Unit:	1284	Outage No.:	2017-07

Equipment Name: Upper Salmon Generating Unit

Brief Description of Event:

Unit was shutdown due to an unusual smell emitting from the unit.

BASIC / ROOT CAUSES Cont'd:

9. Basic/Root Cause Category:

Basic or Root Cause:

Explanation:

10. Basic/Root Cause Category:

Basic or Root Cause:

Explanation:

11. Basic/Root Cause Category:

Basic or Root Cause:

Explanation:

12. Basic/Root Cause Category:

Basic or Root Cause:

Explanation:

13. Basic/Root Cause Category:

Basic or Root Cause:

Explanation:

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Newfoundland & Labrador Hydro
HYDRO GENERATION
EQUIPMENT INVESTIGATION REPORT

HELP

Standing Instruction No. 62
Forced Outage Reporting & Investigation

Location: Upper Salmon **Unit No:** 1 **Business Unit:** 1284 **Outage No.:** 2017-07

Equipment Name: Upper Salmon Generating Unit

Brief Description of Event:

Unit was shutdown due to an unusual smell emitting from the unit.

BASIC / ROOT CAUSES Cont'd:

14. Basic/Root Cause Category:

Basic or Root Cause:

Explanation:

15. Basic/Root Cause Category:

Basic or Root Cause:

Explanation:

REMEDIAL ACTIONS:

	Action	Work Order	Responsible	Target Completion	Comp ?
1.	Increase inspection frequency of rotor keys until		Dan King	2018/12/31	Yes
2.	Refurbish Rotor 2018 Capital Program.		LTAP	2018/12/31	Yes
3.	Monitor unit for abnormal conditions until		Dan King	2018/12/31	Yes
4.	Add inspection checklist to PM checksheets.		LTAP	2017/05/31	Yes
5.	Follow-up with OEM on findings from event.		R. Willcott	2017/04/30	Yes
6.					
7.					
8.					
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10.					
11.					
12.					
13.					
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15.					
16.					
17.					
18.					
19.					

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Newfoundland & Labrador Hydro
HYDRO GENERATION
EQUIPMENT INVESTIGATION REPORT

HELP

Standing Instruction No. 62
Forced Outage Reporting & Investigation

Location: Hinds Lake **Unit No:** 1 **Business Unit:** 1281 **Outage No.:** 2017-10

Equipment Name: Hinds lake Geneerating Unit

Brief Description of Event:

While completing trending of unit Operator noticed and increased in lower generator bearing oil level.

Investigation Assigned to: Alvin Crant

Date of Event: 2017/04/19 **Date of Investigation:** 2017/04/21

Parent Work Order Number: 1254565 **Status of Investigation:** Complete

Alvin Crant	
Signature of Investigator	**Signature of Approver**

Detailed Description of Event:

While operation staff were completing regular schedule trending information from the unit they noticed an increase in the lower generator bearing oil level. There were no alarms associated leading to any change in the operation of the equipment. Oil was drained from the oil water d detector housing and it showed signs of contamination. More oil was drained and eventualy the water in oil alarm activated.
The unit was allowed to run and was shut down later in preperation for further investiagtion and remedial work. The unit was iolated and the coolere were tested and 2 of 6 were found to be leaking. The unit was returned to serfvice with 4 coolers and all trend data was acceptable.

BASIC / ROOT CAUSES:

1. Basic/Root Cause Category: OTHER

Basic or Root Cause: Improper extension of service life

Explanation:

The coolers are original coolers approx 37 years old and have not been replaced or thoroughly inspected since installation. The service life was not accuratley determined due to lack of information on the cooler design and led to running the coolers to this time period.

2. Basic/Root Cause Category: JF - INADEQUATE MAINTENANCE

Basic or Root Cause: Inadequate preventive maintenance

Explanation:

Due to the unit and cooler design a regular inspection of the coolers has not be completed.

3. Basic/Root Cause Category:

Basic or Root Cause:

Explanation:

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Newfoundland & Labrador Hydro
HYDRO GENERATION
EQUIPMENT INVESTIGATION REPORT

HELP

Standing Instruction No. 62
Forced Outage Reporting & Investigation

Location:	Hinds Lake	Unit No:	1	Business Unit:	1281	Outage No.:	2017-10

Equipment Name: Hinds lake Geneerating Unit

Brief Description of Event:

While completing trending of unit Operator noticed and increased in lower generator bearing oil level.

BASIC / ROOT CAUSES Cont'd:

4. Basic/Root Cause Category:

Basic or Root Cause:

Explanation:

5. Basic/Root Cause Category:

Basic or Root Cause:

Explanation:

6. Basic/Root Cause Category:

Basic or Root Cause:

Explanation:

7. Basic/Root Cause Category:

Basic or Root Cause:

Explanation:

8. Basic/Root Cause Category:

Basic or Root Cause:

Explanation:

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Newfoundland & Labrador Hydro
HYDRO GENERATION
EQUIPMENT INVESTIGATION REPORT

HELP

Standing Instruction No. 62
Forced Outage Reporting & Investigation

Location:	Hinds Lake	Unit No:	1	Business Unit:	1281	Outage No.:	2017-10

Equipment Name: Hinds lake Geneerating Unit

Brief Description of Event:

While completing trending of unit Operator noticed and increased in lower generator bearing oil level.

BASIC / ROOT CAUSES Cont'd:

9. Basic/Root Cause Category:

Basic or Root Cause:

Explanation:

10. Basic/Root Cause Category:

Basic or Root Cause:

Explanation:

11. Basic/Root Cause Category:

Basic or Root Cause:

Explanation:

12. Basic/Root Cause Category:

Basic or Root Cause:

Explanation:

13. Basic/Root Cause Category:

Basic or Root Cause:

Explanation:

Printed on: 3/14/2019

HYDRO THE POWER OF COMMITMENT

Newfoundland & Labrador Hydro
HYDRO GENERATION
EQUIPMENT INVESTIGATION REPORT

HELP

Standing Instruction No. 62
Forced Outage Reporting & Investigation

Location: Hinds Lake **Unit No:** 1 **Business Unit:** 1281 **Outage No.:** 2017-10

Equipment Name: Hinds lake Geneerating Unit

Brief Description of Event:

While completing trending of unit Operator noticed and increased in lower generator bearing oil level.

BASIC / ROOT CAUSES Cont'd:

14. Basic/Root Cause Category:

Basic or Root Cause:

Explanation:

15. Basic/Root Cause Category:

Basic or Root Cause:

Explanation:

REMEDIAL ACTIONS:

	Action	Work Order	Responsible	Target Completion	Comp ?
1.	Source replacement coolers.		R. Willcott	2017/10/30	Yes
2.	Arrange temporary repairs.	1255389	K. Inkpen	2017/04/24	Yes
3.	Create Pm inspection program for coolers		B . Woodman	2017/12/31	Yes
4.	Source external cooling.	1257583	C. Steele		Yes
5.	Engage external contarcator for temp repairs	1258510	R. Willcott	2017/05/24	Yes
6.	Source replacement water in oil detector	1255392	R. Woodman	2017/05/24	Yes
7.	Test existing coolers.	1256311	K. Inkpen	2017/05/15	Yes
8.	Fabricate additioanl lifting mechanism	1255391	K. Inkpen	2017/05/24	Yes
9.					
10.					
11.					
12.					
13.					
14.					
15.					
16.					
17.					
18.					
19.					

Newfoundland and Labrador Hydro – a Nalcor Company
Surge & Trouble Report 6922
Bay d'Espoir Unit 7 Trip – 2017/07/03

Issued Report

Prepared By: Art Bursey
Date: 2017/12/08

Review By: ____________________
Date: ____________________

Approved By: ____________________
Date: ____________________

Review By: ____________________
Date: ____________________

Approved By: ____________________
Date: ____________________

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1. Executive Summary

On July 03, 2017 at 17:39:58 hours, Unit 7 at the Bay d'Espoir (BDE) Generating station tripped resulting in an unplanned 11 minute power outage which affected approximately 53,000 customers. At that time, BDE Unit 7 was generating at 125 MW while the total system load was 732 MW. The loss of generation resulted in the system frequency dropping to approximately 58.1 Hz activating under frequency load shedding protection. The load shed caused outages to 47,506 Newfoundland Power customers and 5,422 NL Hydro customers and Corner Brook Pulp & Paper Limited.

BDE Unit 7 tripped due to activation of Unit 7 Lockout by the instantaneous overcurrent protection (50RT) on the excitation transformer which operated at 17:39:58 hours. A review of the System Sequence of Events log discovered that approximately 36 seconds before the unit lockout there was a G7 Excitation Fault alarm triggered. This alarm had picked up and dropped out 20 times starting at 17:39:22 hours with the last alarm at 17:39:58 hours followed by the unit lockout operation. Refer to Appendix G for the Sequence of Events log of the trip.

Hydro's Energy Control Center (ECC) gave notification within two minutes of the event to Newfoundland Power to its restore customers. All NP and NLH customers were restored within 11 minutes of the event occurring. Corner Brook Pulp & Paper were notified by ECC within five minutes to restore normal loading.

Investigation into the trip of Unit 7 determined that there was a flash over between the positive and negative slip rings which resulted in damage to the brush gear. The brushes wore out and over time developed into multiple brush failures and ultimately a flashover on the slip rings resulting in tripping of the unit.

A Tap Root investigation was completed into the Customer Outage and Bay D'Espoir Unit 7 trip. This investigation revealed two causal factors, eight root causes, and 13 corrective actions to address the root causes.

2. Timeline

The following timeline is extracted from the Tap Root Autumn Snap Chart in Appendix A.

Pre-Event

- PM6 - Annual Inspection (July 12, 2016)
- PM9 - Six Year Inspection (July 12, 2016)
- 2015 Replaced Slip Ring (September 2015)
- 2015 All New Brushes (September 2015)
- Polarity reversed on slip rings (July 12, 2016)

Event Summary

- Generator Failure (July 3, 2017)
- Exciter Protection Operation (July 3, 2017)
- Unit Lockout Trip - unit offline (July 3, 2017)
- Load Shedding resulting in 53,000 customer load loss – activation of UFLS (July 3, 2017)
- Customer Outage (July 3, 2017)
- Unit Testing (July 4 to July 7, 2017)

Post-Event

- Unit Repair, Slip ring repair, re-install, mechanical testing (July 8 – July 9, 2017)
- Unit on-line testing, Unit released to ECC for normal operation (July 9, 2017)
- Tap Root Investigation was initiated (July 11, 2017)

3. Description of Equipment

The slip ring and brushes are part of the generator excitation system. The excitation system provides on a continuous basis, the field current necessary to maintain the proper voltage at the generator terminals under varying conditions of load. The slip ring is a band of electrically conductive material, mounted on a shaft. Although it's insulated from the shaft itself, the slip ring is connected to the rotor through electrical connections. The outer part of this slip ring remains in continuous sliding contact with the stationary brushes which provides

continuous rotating unbroken contact between the rotating assembly and external circuit. This ensures slip rings are able to transmit power at all times.
Slip rings may appear to be complicated devices, yet most all standard mechanical slip rings can be easily broken down into two major components, these are:

The Brush

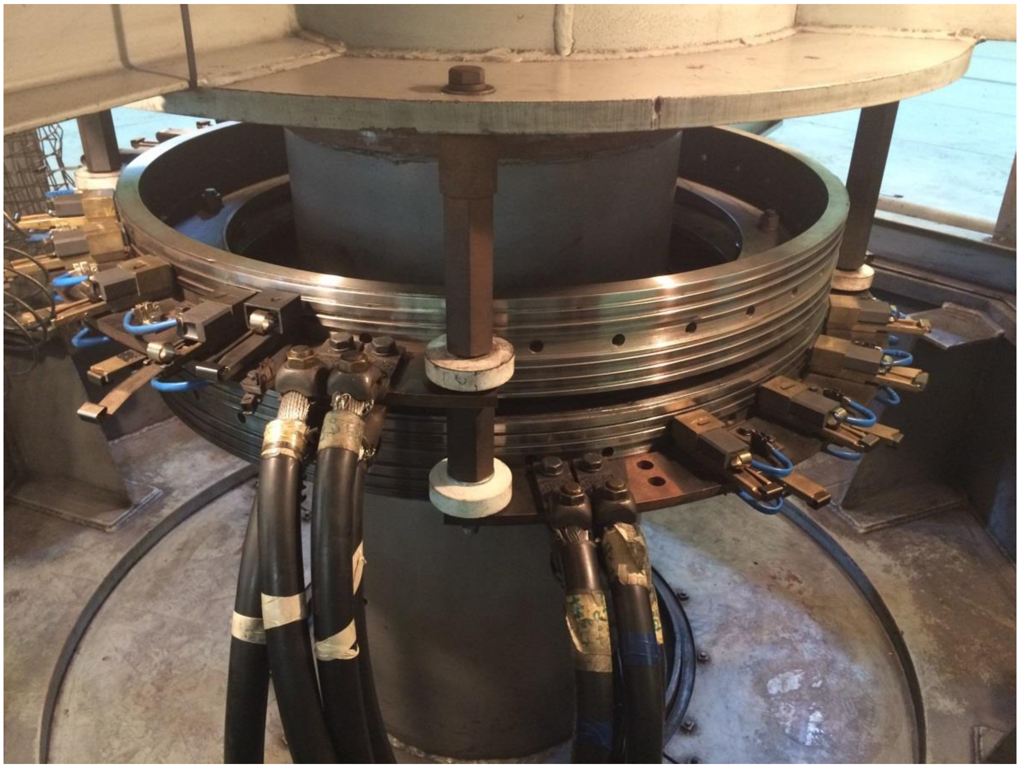
The brush is a stationary contact made of either graphite or metal, which then rubs against the outside of the rotating metal ring.

The Ring

The ring is made of electrically conductive metal, usually brass, and is mounted on but insulted from the center shaft. The insulation between the shaft and ring is generally made of any number of synthetic materials, including nylon and phenolic plastic. As the ring turns, the electric current is conducted through the brush to the ring making connection. The slip ring is properly matched with the right brush, which is why they're often sold as a set, known as a slip ring Assembly.

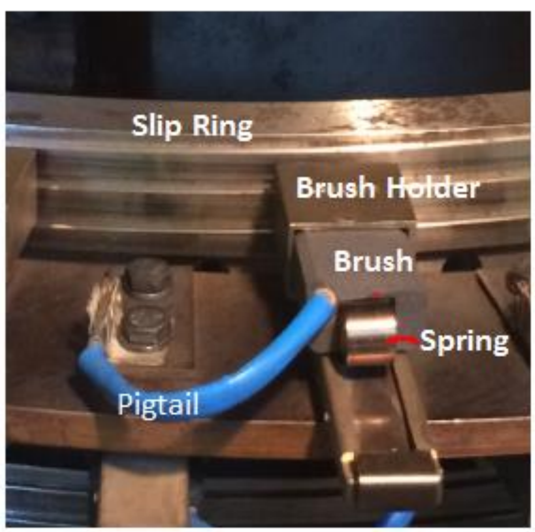
The pictures 1 and 2 show the complete slip ring and brush assembly on Unit 7 with new brushes and a cleaned slip ring.

Picture 1: Cleaned slip ring with new brushes and brush holders



Picture 2: Different angle of complete slip ring brush installation

Picture 3, shows an example of a new slip ring and brush gear assembly and a typical failed assembly. This is a new brush set-up with a cleaned slip ring. Picture 4, shows a typical damaged brush. Refer to Section 9 for additional pictures and Appendix B, for a report outlining the damage to the brush gear and slip ring.



Picture 3 – Slip ring and brush gear assembly

Picture 4 – Typical damage to brush

4. Pre Event Conditions

Unit 7 had been operating continuously since its last annual planned outage (which ended on August 24, 2016) except for a 14 hour planned maintenance outage on June 21, 2017. This maintenance outage was required to work on filters in the governor oil system. Unit 7 has a total operating factor[1] of 99.7% since August 27, 2016 to June 30, 2017. During this period there have been no alarms or issues identified with its operation.

During the last annual unit outage which was performed in July, 2016, using PM9 revision 6, the brushes below the minimum wear level[2] were replaced on the upper ring and the ring polarity was reversed. None of the lower slip ring brushes required replacement. Ring polarity reversal is done to minimize the rate of wear on brushes and rings. This reversal resulted in the lower ring becoming the positive ring and vice versa. In Hydro's experience, the positive ring usually experiences the higher rate of wear compared to the negative ring.

[1] Operating Factor is defined as the total generating time divided by the total period hours.
[2] Minimum brush wear is the point where the brush will lose contact with the slip ring before the next inspection interval

The brush grade had been changed in recent years due to industry consolidation of the brush manufacturers. This item is noted as brush grade can contribute to the wear rate of brushes however they are not considered to be the cause of brush failure in this event.

5. Summary of Event

On July 03, 2017 at 17:39:58 hours, Unit 7 at the Bay d'Espoir Generating station tripped ultimately resulting in an unplanned 11 minute power outage which affected approximately 53,000 customers (583,000 customer minutes). There was no abnormal system or weather conditions at the time of the trip. At that time, BDE Unit 7 was generating at 125 MW which was 17% of the total system load of 732 MW. The loss of generation resulted in the system frequency dropping to approximately 58.1 Hz activating under frequency load shedding protection. The load shed caused outages to 47,506 customers Newfoundland Power and 5,422 customers NL Hydro and Corner Brook Pulp & Paper Limited.

Bay d'Espoir (BDE) Unit 7 tripped due to activation of Unit 7 Lockout. The unit lockout was activated by the instantaneous overcurrent protection (50RT) on the excitation transformer which operated at 17:39:58 hours. A review of the System Sequence of Events log discovered that approximately 36 seconds before the unit lockout there was a G7 Excitation Fault alarm triggered. This alarm had picked up and dropped out 20 times starting at 17:39:22 hours with the last alarm at 17:39:58 hours followed by the unit lockout operation. Refer to Appendix G for the Sequence of Events log of the trip.

Hydro's Energy Control Center (ECC) gave notification within two minutes of the event to Newfoundland Power to restore its customers. All NP and NLH customers were restored within 11 minutes of the event occurring. Corner Brook Pulp & Paper were notified by ECC within five minutes to restore normal loading. Table 1 outlines the customer load loss as a resulted of the under frequency load shedding protection.

Table 1: Customer Load Shed Details

Customer Group	Customers Affected	Load Shed
Corner Brook Pulp and Paper	1	30 MW
NL Hydro	5,422	9.7 MW
Newfoundland Power	47,506	88 MW
Total Load Shed	52,929	127.7 MW

6. Technical Investigation

6.1 Initial Investigation

Plant Operators immediately went to Powerhouse 2 to investigate the tripping of Unit 7. Upon arrival they did not report any visual indication of smoke or any unusual odours.

6.2 Trouble Shooting

An inspection of the protection panels determined the unit had locked out after the operation of the instantaneous over current protection (50RT) on the excitation transformer. This led to the initial thought that an exciter issue had occurred and the damage was the result of an exciter problem. Further investigation determined there was no trip initialized from the exciter and no alarms indicating an exciter fault. This was confirmed by an ABB engineer who arrived at Bay d'Espoir on July 6. The ABB engineer with site assistance from Engineering Services reviewed the exciter operation. This inspection determined there were no problems or components malfunctions with the excitation system[3].

Refer to Appendix E, for additional details on testing which was completed on the unit.

6.3 Brush gear Inspection

Long Term Asset Planning, Hydro Generation completed a mapping of the damage to the slip (collector) rings and brush gear. Refer to Appendix B for the full report with pictures. Highlights from the report are as follows;

- The unit was in service for a little under a year since the last PM6[4] inspection was performed on the unit. (July 2016)
- During the 2016 PM9[5] outage, the brushes were inspected and 11 of 20 brushes on the top slip ring were replaced due to wear, and all brushes on the bottom slip ring were well within the minimum brush wear tolerance and were reused.

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[3] The field service report from ABB is available in Appendix V.

[4] PM6 is defined as Preventive Maintenance Inspection which is completed annually.

Top slip ring: negative ring

- Only one of 20 brushes was below minimum brush wear tolerance. All others brushes were above the minimum wear tolerance but within limits of what was acceptable would have been probably replaced on the next inspection.
- The level of carbon dust on the brush rings was typical of a normally functioning brush and ring assembly operating since the last maintenance.
- There were no obvious signs of heat damage to this ring or the associated brush components.
- The surface was smooth with no signs of irregular wear.

Bottom slip ring: positive ring

- Five brushes were burnt up and severely damaged and fell out of the brush holders The other five brushes were worn below the minimum acceptable wear level
- There were signs of excessive overheating on the full profile of the ring.
- There were no signs of irregular wear prior to the failure – lack of gouging, etc.
- The surface was rough (fine pitting / splatter) around the entire circumference on both the upper and lower sections.

The visual inspection of the slip rings suggested that the lower ring was damaged by electrical arcing between the ring surface and the brushes/brush holders.

6.4 Hydro Generation, LTAP Maintenance Notes

Maintenance notes on slip ring collected by Hydro Generation, LTAP

- Varity of inspection intervals across time and industry. Historically, Hydro's hydraulic units were checked and replaced if necessary semi-annually. Thermal units were checked and replaced on-line weekly. Changed many years ago to an annual inspection and changed based on condition for all sites. No major incident across all units until now.
- Churchill Falls inspects daily/weekly by operators who can see by opening a door.
- Not all units can be inspected on-line. BDE Unit 7 and Cat Arm Units 1 & 2 can. Other units require a shut down and have a cover removed to insert a borescope or pole mirror to view remaining brush length.

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[5] PM9 is defined as Preventive Maintenance Inspection which is completed every five years.

- Most units require a one to two day planned outage to replace brushes
- The planned maintenance schedule was changed from semi-annual to annual. It is not known why this change was made but it's believed to be due in part due to System Operations hesitancy to shut down units during the winter availability season (November 15th to March 31th)

History notes on slip ring failure collected by Hydro Generation, Long Term Asset Planning (LTAP)

- New slip ring installed in September 2015 – all new brushes
- In July 2016, 11 of 20 brushes on the positive ring were replaced due to wear, no negative brushes were replaced. Then the polarity was reversed.
- No brush gear inspections from July 2016 until unit trip on July 3, 2017

6.5 Failure Description

When the failure occurred the lower ring brushes had been in service for almost two years continuous operation. Calculations determined that two years of continuous normal operation would have worn the brushes to the point where replacement was required.

During the investigation the slip ring was dismantled by Hydro Generation and removed for a more detailed inspection and showed the following;

- Damage to the surface of the lower ring was minor, indicating that the ring could be repaired by machining and polishing.
- The two sets of slip ring insulators (four between the upper and lower rings and four between the lower ring and the drive disc) were in acceptable condition as indicated by 5 kV Megger tests.
- The arcing damage between the upper and lower rings was minor and did not require repair.
- And there was no other damage to the unit.

6.6 Conclusion of Investigation

The conclusion of the investigation into the trip of Unit 7 determined that there was a flash over between the positive and negative slip rings which resulted in damage to the brush gear. The brushes wore out and over time developed into multiple brush failures and ultimately a flashover on the slip rings resulting in tripping of the unit.

The cause of the failure was excessive wear (insufficient length) of the brushes operating on the lower slip ring. The brushes were worn to the point where the ends of individual brushes were entering their brush holders. When a brush is worn to this extent, the brush pigtail can interfere with the edge of the brush holder and restrict further inward movement of the brush. Also, at this point, the brush holder spring is at the end of its travel and there is loss of pressure on the brush. The result is that the brush loses proper contact with the slip ring and causes arcing between the brush and the ring. Arcing causes deterioration of both the brush and the ring, which accelerates overtime. This would cause an increase in current on the remaining brushes which resulted in damage to the pigtails and the melting of the brush holders. It is expected that this condition generated gaseous and particulate products in the air surrounding the brush gear resulting in the establishment of electrical arcs between the lower slip ring and the upper slip ring. It is expected that these arcs resulted in overloading of the excitation transformer and subsequent tripping of the unit.

7. Return to Service

Repairs

The slip rings were removed and sent to a machine shop to be cleaned and resurfaced. All other parts required to install the rebuilt slip rings and new brushes and associated brush gear was available in Bay d' Espoir.

Unit Return to Service

The slip ring was installed in the morning of July 8 and the penstock was watered up on July 8 and July 9. The first mechanical run was completed on July 9. During this run some brushes did not make proper contact with the slip ring. The slip ring was realigned and the mechanical run was completed with no issue. After this work was completed the unit was synchronized to the grid and ran under load for approximately 60 minutes. No issues were found and it was released to ECC for normal service on July 9 at 2151 hours.

8. Tap Root Investigation -Causal Factors & Root Causes

The causal factors[6] were identified based on the sequence of events and the associated conditions leading to the incident. They were then analyzed through the Tap Root process. The following is commentary on the Causal Factors and Root Causes[7] of the incident.

The Tap Root investigation into the Customer Outage and Bay D'Espoir Unit 7 trip on July 3, 2017 revealed two causal factors, eight root causes, and 13 corrective actions[8] to address the root causes.

Causal factor 1: Load shedding resulting in 53,000 customer load loss.

This causal factor was identified during the investigation as contributing cause to the unplanned customer outage. The current Interconnected System configuration requires the use of under frequency load shedding (UFLS) to prevent customer equipment damage and damage to NL Hydro's assets. In the future with the Labrador Infeed and the Maritime Link, this could mitigate customer load shedding due to generation loss.

There is a Unit Maximum Load Guideline[9] in place which determines the maximum generating unit loading depending upon total system generation. This guideline is used by the ECC operators to determine maximum loading for the largest unit connected to the system for varying system loads and industrial load availability to avoid a UFLS event. The Unit Maximum Load Guideline was followed correctly by ECC operators.

Root Cause #1: Unit Maximum Loading Guideline allows for customer outages.

Corrective Actions for improvements to Root Cause 1:

1. Review Unit Maximum Loading Guidelines to determine if any improvements can be made to reduce customer outages.

   Person Responsible: Engineering Services – P&C Engineering
   Target Date: March 31, 2018

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[6] Causal Factor - A problem or issue that, if corrected, could have prevented an incident from occurring or significantly reduced the incident's consequences

[7] Root Cause - The most basic cause (or causes) that can reasonably be identified that Management/Leadership has control to fix and, when fixed, will prevent (or significantly reduce the likelihood of) the problem's recurrence. Root Causes are identified using the Tap Root process.

[8] Corrective Action - Action taken to prevent the recurrence of an incident. The responsibility to complete the action is assigned to a single individual along with a target completion date.

[9] System Operating Instruction T-068, refer to Appendix F

Causal Factor 2: Excessive Brush Wear:

This causal factor refers to the fact that the excessive brush wear if detected earlier would have prevented the unit trip.

The following are the major contributors/factors determined during the Tap Root process which led to the failure. These conditions are:

- Semiannual unit inspections cancelled
- No specification for brushes
- Warehouse technical inspection of brushes was not completed
- The brush length changed from 4 ½ inches to 3 inches (same part number and supplier)
- 2016 inspection replaced brushes as per inspection sheets. Leaving some brushes which were not long enough the last until the next PM inspection.
- PM check sheets outline brush replacement at 1/8 inch brush wear remaining however replacement was being done at ½ inch brush wear remaining. Conflicting with the documentation.
- Older revisions of PM check sheet being used on inspections. Only current revision should be used with updated information.
- The slip ring was replaced in 2015 with a new ring and all new brushes. The rate of brush wear is not known with the new slip ring.
- PM check sheets are not being reviewed as per Asset Management procedures for rate of brush wear.
- PM check sheet regularly showed that brushes reached the minimum acceptable length but not flagged or noted for replacement.
- Rate of brushes wear can exceed the current maintenance replacement practice, during this investigation it was estimated that the brush wear was approximately ¾ inch per year.

Root Cause #2: - Wrong information (facts) used on PM inspection sheets

Discussion for Root Cause 2

Specific maintenance items are completed annually and others after five year intervals. Check sheets are completed for each annual PM6 maintenance and PM9 five year maintenance. Document control of check sheets used for inspections needs to be reviewed and revised as required. It should be ensured that only the latest revision is used and the information on the sheets is accurate.

Two of the maintenance check sheets which were inspected during the analysis were found to have errors in that the brush replacement intervals stated on the PM6 and PM9 forms were found to be different. Specifically, the PM6 which is used to record annual maintenance data stipulated that the minimum brush tolerance was ½ inch whereas the PM9 form which records the 5 year maintenance data stipulated 1/8 inch.

Corrective Actions for Root Cause 2:

2. Improve document control procedures for check sheets used for inspections.
   Person Responsible: Hydro Generation - LTAP
   Target Date: March 31, 2018

3. Revise procedures on PM6 (annual) and PM9 (five year) check sheets.
   Person Responsible: Hydro Generation - LTAP
   Target Date: April 30, 2018

4. Review PM check sheets to be determine brush instructions are current.
   Person Responsible: Hydro Generation - LTAP
   Target Date: April 30, 2018

Root Cause #3 - Wrong Revision of PM inspection sheets used

Discussion for Root Cause 3

Workers have been using check sheets of different revision numbers to complete inspections. These check sheets had differing information (Appendix I). There may be a problem with the usage of noncurrent document revisions. Some of the later PMs were conducted using earlier versions of the check sheets.

Corrective Actions for Root Cause 3:

5. Ensure that only the latest revision of PM check sheets is used.
   Person Responsible: Hydro Generation – Work Execution
   Target Date: March 31, 2018

Root Cause #4 – No Engineering standards in procurement of brush and acceptances

No Procurement Policy – Brush Specification purchasing and acceptances

A purchasing standard or specifications for procurement of brushes does not exist.

The purchasing of brushes does not have a document with a detailed description of the brush components or materials composition. It is noted that brushes received were 3" whereas 4 1/2" were listed in JD Edwards inventory. There is no technical inspection of brushes upon receipt at the warehouse. Improvements are required to provide a minimum specification to ensure the receipt of acceptable brushes.

Corrective Action for Root Cause 4:

6. Develop a brush standard and specification.
   Person Responsible: Hydro Generation - LTAP
   Target Date: March 31, 2018

7. Develop a technical inspection document for receipt of brushes at the warehouse.

   Person Responsible: Hydro Generation - LTAP
   Target Date: March 31, 2018

Root Cause #5 - Infrequent review (audits) and evaluation of PM inspection sheets

Inspection sheets review

Previous inspection sheets had brushes recorded as zero wear remaining. A review of these PM inspection sheets by Front Line supervisors would have detected this as a problem with the inspection interval. During the investigation an analysis of the wear rate was performed and indicated that the interval between inspections of brushes for possible replacement was inadequate (Appendix I). Analysis of brush wear rates should be performed regularly with reference to operating hours. Data is available from check sheets on brush wear but no analysis (trending) of the data is being performed.

False assumptions were made in that 1/2" brush remaining was acceptable for operating to the next maintenance interval without confirmation through wear rates analysis. This could have been prevented by review of the PM check sheets with timely corrective actions. In the past check sheets were reviewed by additional levels of supervisors. Asset Management guidelines do outline the current procedures. Improved quality control of check sheets should be provided.

Corrective Action for Root Cause 5:

8. Review Asset Management procedures and responsibilities with front line Hydro Generation personnel to improve or familiarize them with the procedures and inspections results.

   Person Responsible: Hydro Generation – Work Execution
   Target Date: January 31, 2018

Root Cause #6 – Limited or not effective employee feedback on PM inspection sheets

Ensure compliance in checking PM inspection sheets by for process equipment issues by front line employees

Ensure compliance for maintenance technicians to pass feedback to management. However, as noted above, it appears this has been applied somewhat informally as electricians use the ½ inch acceptance criteria even though the check sheet they are using indicates 1/8" acceptance. Additionally, there was an example where zero brush life remaining was not noted on an inspection sheet (Appendix I) for follow up with further investigation.

Corrective Actions for Root Cause 6:

9. Review Asset Management policies with supervisors and LTAP personnel in Hydro Generation to improve or familiarize them with the procedures and review concerns with the inspections results.

   Person Responsible: Hydro Generation – Work Execution
   Target Date: March 31, 2018

Root Cause #7 – No detailed trending of PM inspection sheets

Implement a trending analysis for information on check sheets

There is no formal documented program for maintenance technicians or Hydro Generation LTAPs to trend information collected during unit PMs. This information is required to ensure the units are addressed before deterioration or wear surpass acceptable limits.

Corrective Actions for Root Cause 7:

10. Investigate further the possibility of implement trending analysis to monitor brush wear and determine when replacement should occur.
    Person Responsible: Hydro Generation - LTAP
    Target Date: March 31, 2018

Root Cause #8 – PM6 and PM9 for equipment not fully Implemented

Develop and revise PM check sheets used for generators.

The preventive or predictive maintenance program did not allow or account for brush wear over the shortest maintenance period (annually). The existing program is inadequate as the estimated rate of brush wear is more than the ½ in acceptance allowance that was being used. There is no OEM documentation on file regarding the rate of brush wear or grade of brushes to be used. Brush grade should be approved by the OEM and rate of wear determined by the owner through frequent monitoring with reference against operating hours. Maintenance practices allowed brushes with 1/2" wear to remain however they could

Corrective Actions for Root Cause 8:

11. Develop improved and more detailed procedures for brush replacement.
    Person Responsible: Hydro Generation - LTAP
    Target Date: March 31, 2018

12. Hydro Generation LTAP to determine the rate of wear and minimum brush wear measurement for the brushes.
    Person Responsible: Hydro Generation - LTAP
    Target Date: March 31, 2018

9. Additional Follow-up Actions

As a result of the TapRoot investigation, items were identified which should be considered.

1. Analysis of the brush wear rates for Unit 7 indicated that the brush replacement intervals were not frequent enough to avoid a brush failure. It is advisable to ensure appropriate brush analysis is being conducted on other generators.
   Person Responsible: Hydro Generation - LTAP
   Target Date: March 31, 2018

2. This report should be circulated to all Hydro and Nalcor generating groups.
   Person Responsible: Hydro Generation - LTAP
   Target Date: March 31, 2018

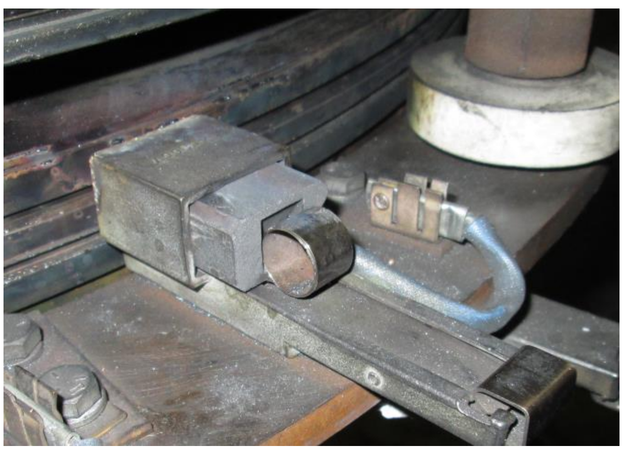
3. Investigate the possibility of adding an additional alarm level to the excitation transformer overcurrent relay to detect an increase in current related to a brush(s) failures
   Person Responsible: Engineering Services – Technical Services
   Target Date: March 31, 2018

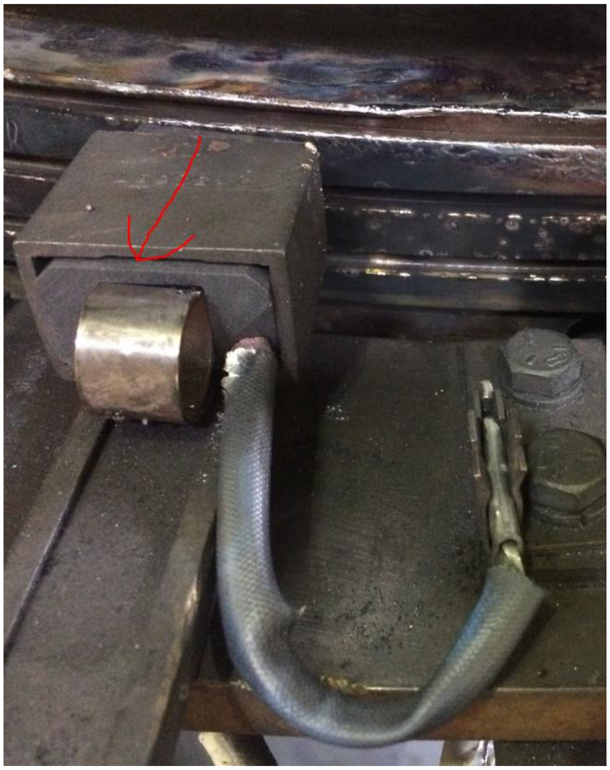
4. Review the annunciation in Powerhouse 2 versus Powerhouse 1, ensure critical alarms are included.
   Person Responsible: Hydro Generation - LTAP
   Target Date: March 31, 2018

10. Pictures

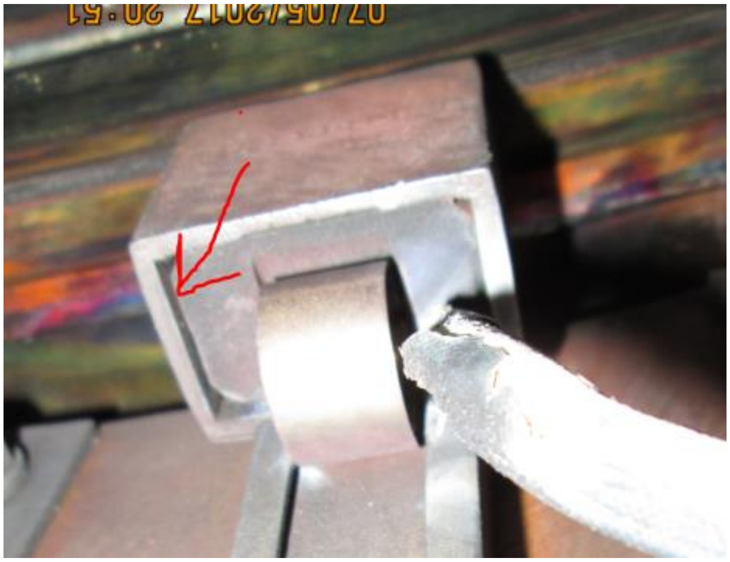
The following pictures are samples, the complete collection of pictures can be found on at: *X:\BDE Unit #7 Trip July 3, 2017\Pictures from Unit 7*

Missing Brush and melted brush holder with lead burnt off

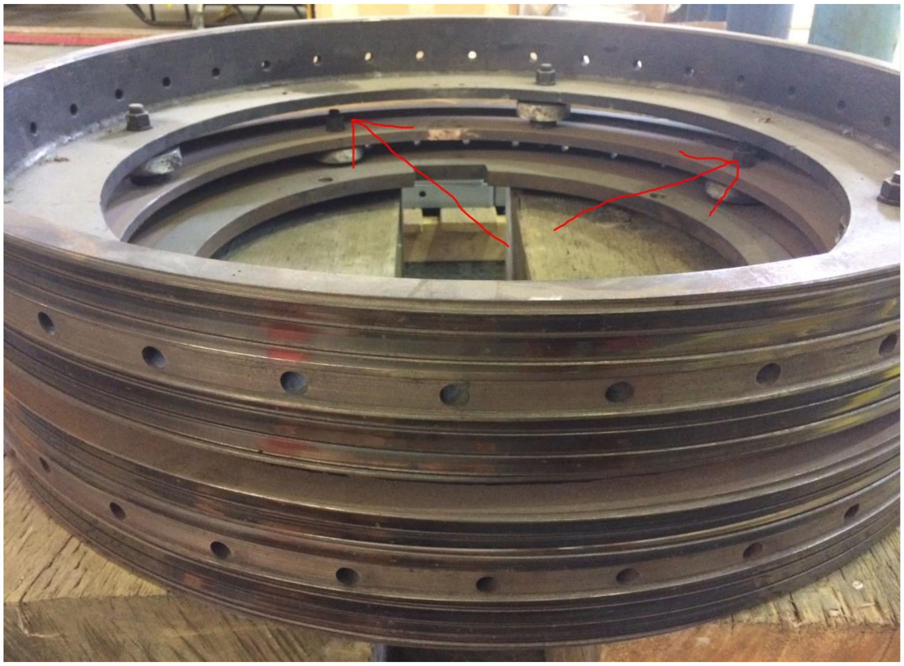

Acceptable brush with remaining wear


Not acceptable brush, less than acceptable wear remaining

Lead burnt off and brush wear at zero remaining life


Brush with zero wear remaining


Close-up of a flashover point between the slip rings



Picture of the slip ring, arrows indicated the flashover points (not all flashover points are indicated)

11. Investigator/Investigation Team

An analysis team was put in place on Wednesday, July 12, 2017 to review the incident to determine the root causes and identify corrective actions to mitigate the event from happening again. The investigation was completed on July 15, 2017. The team members are:

<u>TEAM MEMBERS</u>

Art Bursey	Team Lead	Engineering Services
Brian Tink	TapRooT Facilitator	System Improvements Inc.
Ern Buglar	Investigator	Engineering Services
Alvin Crant	Investigator	Hydro Generation
Charles Ezeoru	Investigator	Hydro Generation

<u>TEAM GOVERNANCE</u>

Nelson Seymour	Sponsor	Engineering Services

12. References & Attachments

Note: Appendix A to H is enclosed in this report, while the others are available in X:\BDE Unit #7 Trip July 3, 2017\Report Appendix

Appendix	Document	Notes
A	TapRoot Snap Chart flow chart	
B	Mapping Report into Slip (collector) Ring Failure	Bob Woodman's notes on the brush failure mapping
C	Causal Factor Root Cause Tree	Load Shedding resulting in 53, 000 customer load loss
D	Causal Factor Root Cause Tree	Excessive Brush wear
E	Testing Report Notes on Unit 7	
F	Guideline for Unit Maximum Loading	
G	System Sequence of Events - Partial	
H	PUB Outage Advisories forms, 2017-H-027-a and 2017-H-028-a	
I	Notes on Slip ring failure information, BDE Planned Maintenance Procedures, inspection forms, PM master form (GEN-52), PM9 inspection sheet (22 pages)	
J	Relay targets – photo of excitation relay ABB SPAJ 140C (NEED TO HAVE RELAY TARGET CARD)	
K	Minutes of update and technical meetings	

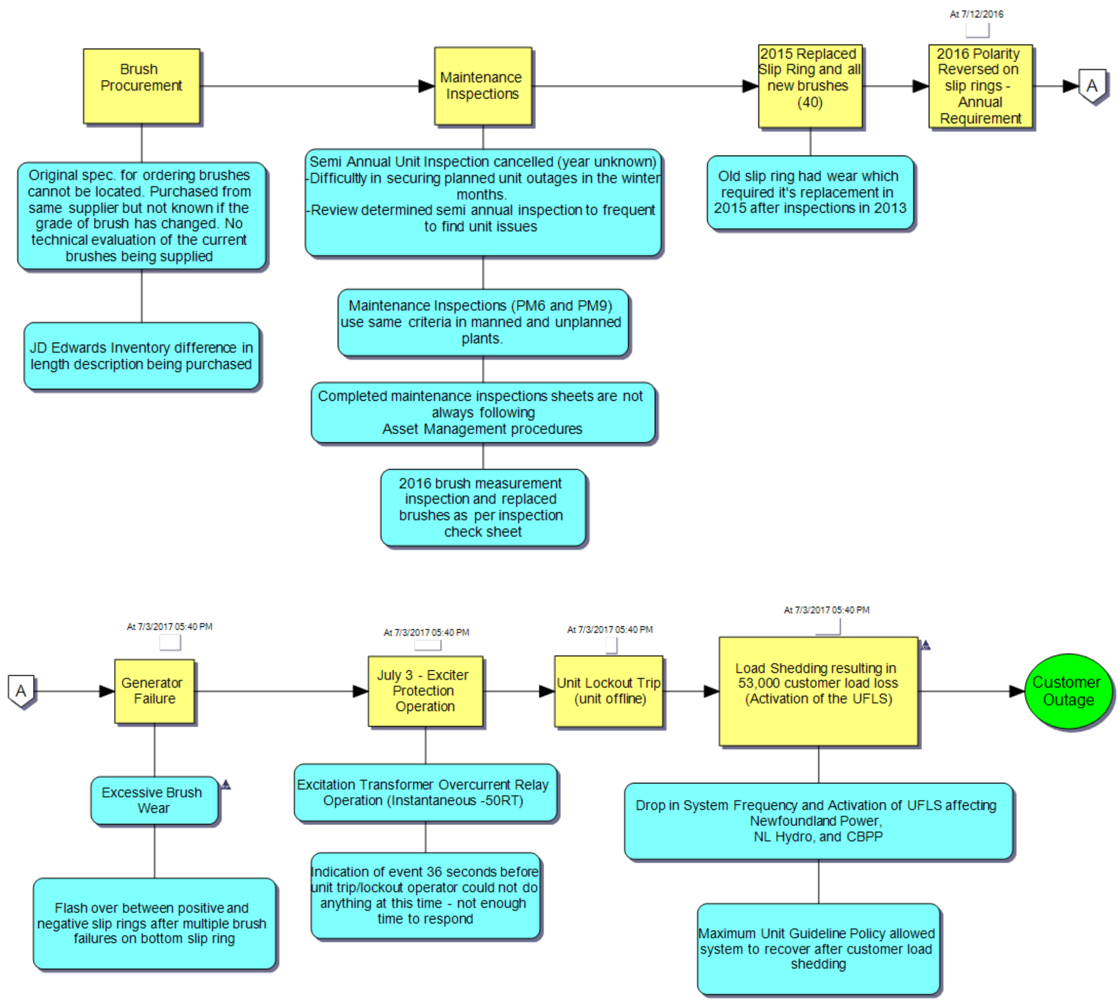
L	Art Bursey email dated July 4, 2017 at 04:31 PM	
M	Question to CEATI and CEA Generation Groups – Root Cause Analysis – Nova Scotia Power May 11, 2016	
N	Churchill Falls PM Program	
O	Complete System Sequence of Event Log for event	
P	Brush Information, Mersen carbon brush guide	
Q	CPM of Unit 7 Repair	
R	Test Results of exciter SCR, exciter PT's, excitation transformer	
S	Test Results of PI, pole drop, slip ring, and annunciator checks	
T	Excitation Transformer test results	
U	ABB Field Service report on Exciter Inspection	

APPENDIX A – TapRoot Snap Chart Flowchart

The Tap Root investigation into the Customer Outage and Bay D'Espoir Unit 7 trip on July 3, 2017 revealed two causal factors, eight root causes, and 13 corrective actions to address the root causes.

The sequence of events leading to the Customer Outage is illustrated in the following diagram.

Diagram 1: Tap Root Winter Snap Chart



The causal factors[10] (CF) include:

1. Under frequency load shedding occurred as a result of the system frequency dropping below 58.8 Hz.

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[10] Causal Factor - A problem or issue that, if corrected, could have prevented an incident from occurring or significantly reduced the incident's consequences

2. Excessive Brush wear resulting in a flashover between the positive and negative slip rings

The following root cause[11] was identified based on a Tap Root analysis of Casual factor 1:

1. Unit Maximum Loading Guideline allows for customers outages.
   (Standards, Policies, or Administrative Controls – Not Strict Enough – CF1)

The corrective action[12] plan to correct the Causal factor 1:

Review Unit Maximum Loading Guidelines to determine if any improvements can be made to reduce customer outages.

The following root causes[13] were identified based on a Tap Root analysis of Casual factor 2:

2. Wrong information (facts) used on PM inspection sheets (CF 2)
3. Wrong revision of PM inspection sheets used (CF 2)
4. No Engineering standard in procurement of brush and acceptances (CF 2)
5. Infrequent review (audits) and evaluation of PM inspection sheets (CF 2)
6. Limited or not effective employee feedback on PM inspection sheets (CF 2)
7. No detailed trending of PM inspection sheets (CF 2)
8. PM6 and PM9 for equipment not fully implemented (CF 2)

The corrective action[14] plan to correct the root causes for Causal Factor 2:
Root Cause 2 & 3

- Improve document control procedures for check sheets used for inspections
- Revise procedures on PM6 (annual) and PM9 (five year) check sheets.

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[11] Root Cause - The most basic cause (or causes) that can reasonably be identified that Management/Leadership has control to fix and, when fixed, will prevent (or significantly reduce the likelihood of) the problem's recurrence. Root Causes are identified using the Tap Root process.
[12] Corrective Action - Action taken to prevent the recurrence of an incident. The responsibility to complete the action is assigned to a single individual along with a target completion date.

[13] Root Cause - The most basic cause (or causes) that can reasonably be identified that Management/Leadership has control to fix and, when fixed, will prevent (or significantly reduce the likelihood of) the problem's recurrence. Root Causes are identified using the Tap Root process.
[14] Corrective Action - Action taken to prevent the recurrence of an incident. The responsibility to complete the action is assigned to a single individual along with a target completion date.

- Enforce that only the latest revision of PM check sheets is used.
- Review PM check sheets to be determine instructions are current.

Root Cause 4

- Develop a brush standard and specification.
- Develop a technical inspection document for receipt of brushes at warehouse.

Root Cause 5

- Review Asset Management roles and responsibility with front line Hydro Generation personnel. (RC5)

Root Cause 6

- Review Asset Management procedures with second line supervisors and LTAP personnel Hydro Generation personnel to improve or familiarize with the procedures and review concerns with the inspections results.

Root Cause 7

- Investigate further the possibility of implement trending analysis to monitor brush wear and determine when replacement should occur.

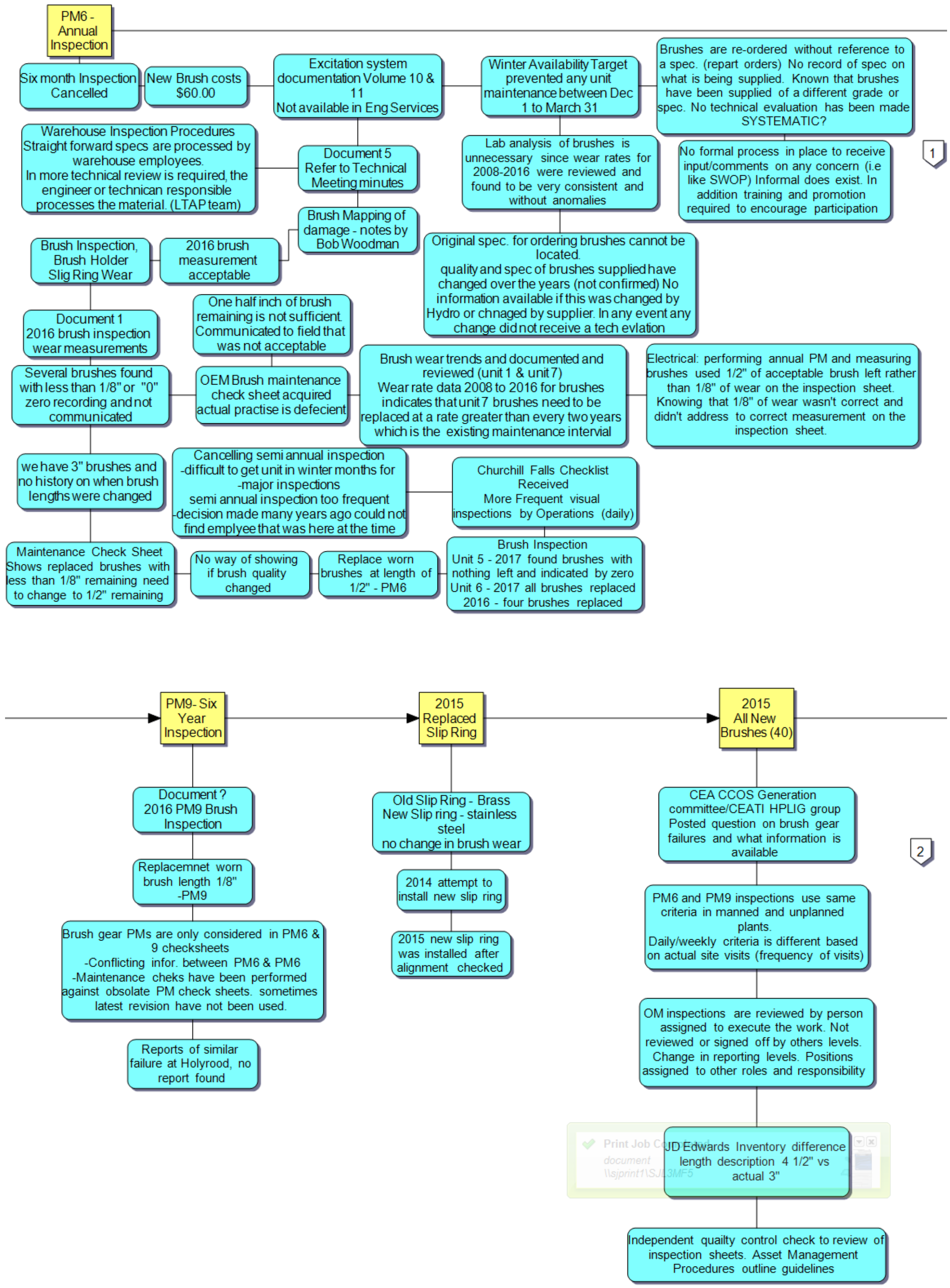
Root Cause 8

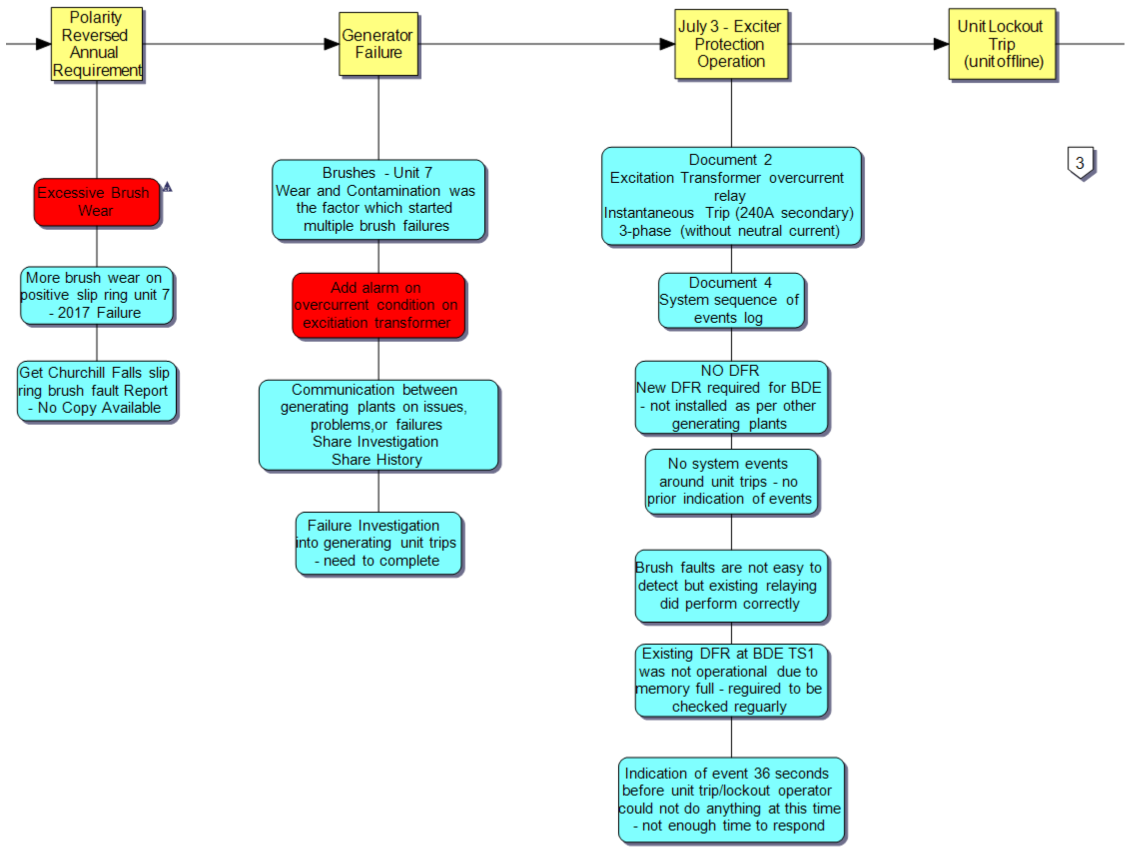
- Develop improved and more detailed procedures for brush replacement.
- Hydro Generation LTAP to determine the rate of wear and minimum brush wear[15] measurement for the brushes.

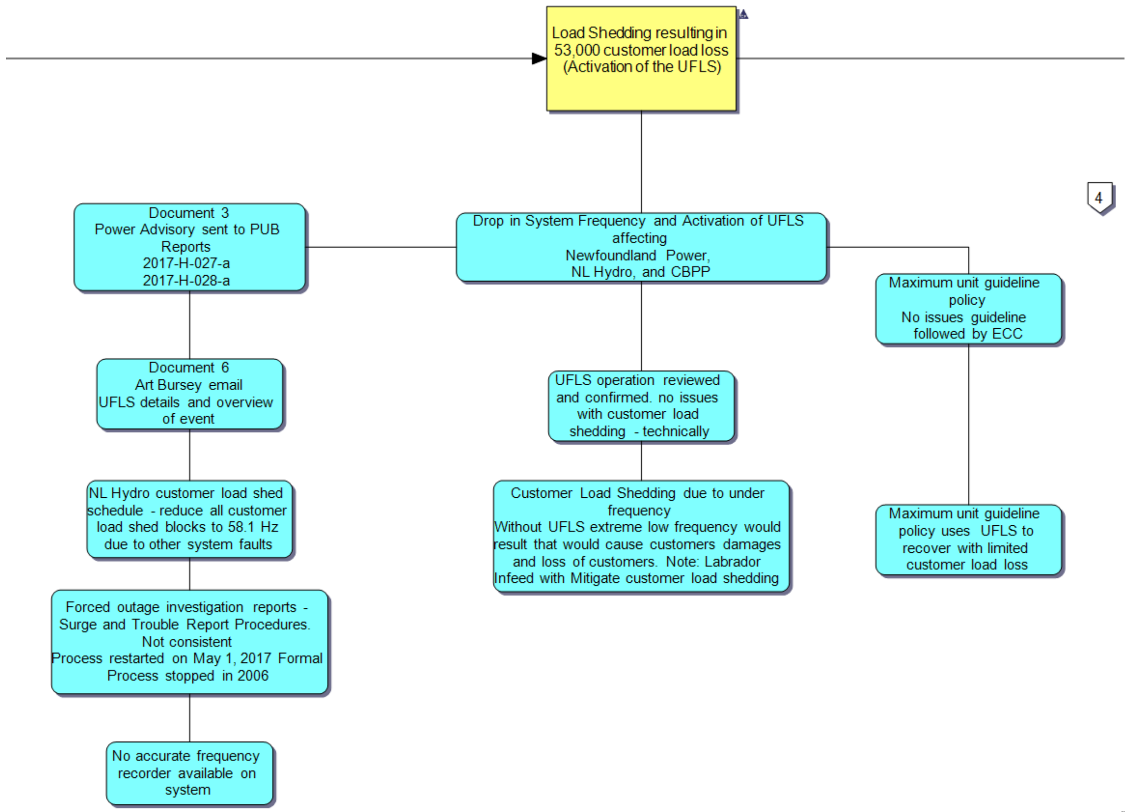
Additional corrective actions not related to a specific root cause:

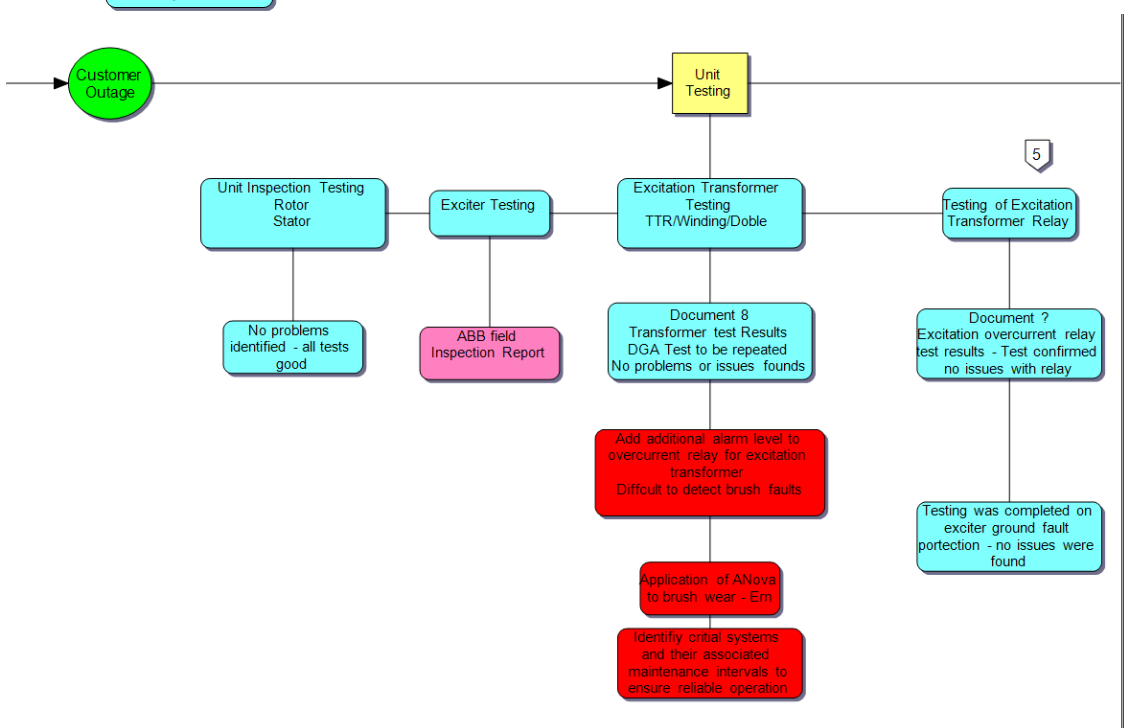
- Add an additional alarm level to the excitation transformer overcurrent relay to detect an increase in current related to brush(s) failures.
- Review the annunciation in Powerhouse 2 and Powerhouse 1, ensure critical alarms are included.

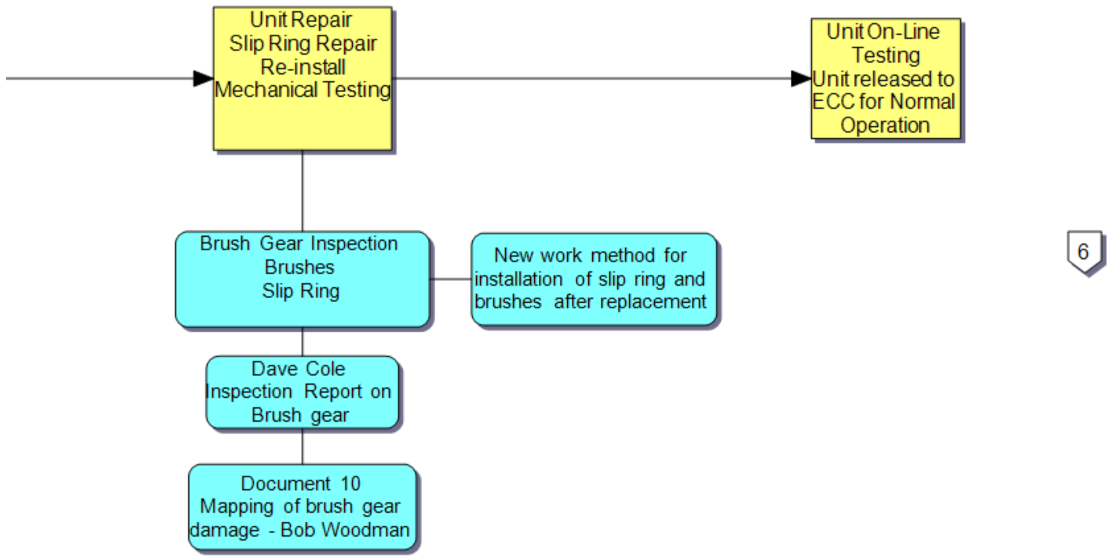
[15] Minimum brush wear is the point where the brush will lose contact with the slip ring before the next inspection interval


PM6 - Annual Inspection
Six month Inspection Cancelled
New Brush costs $60.00
Excitation system documentation Volume 10 & 11 Not available in Eng Services
Winter Availability Target prevented any unit maintenance between Dec 1 to March 31
Brushes are re-ordered without reference to a spec. (repart orders) No record of spec on what is being supplied. Known that brushes have been supplied of a different grade or spec. No technical evaluation has been made SYSTEMATIC?
1
Warehouse Inspection Procedures Straight forward specs are processed by warehouse employees. In more technical review is required, the engineer or technican responsible processes the material. (LTAP team)
Document 5 Refer to Technical Meeting minutes
Lab analysis of brushes is unnecessary since wear rates for 2008-2016 were reviewed and found to be very consistent and without anomalies
No formal process in place to receive input/comments on any concern (i.e like SWOP) Informal does exist. In addition training and promotion required to encourage participation
Brush Mapping of damage - notes by Bob Woodman
Brush Inspection, Brush Holder Slig Ring Wear
2016 brush measurement acceptable
Original spec. for ordering brushes cannot be located. quality and spec of brushes supplied have changed over the years (not confirmed) No information available if this was changed by Hydro or chnaged by supplier. In any event any change did not receive a tech evlation
Document 1 2016 brush inspection wear measurements
One half inch of brush remaining is not sufficient. Communicated to field that was not acceptable
Several brushes found with less than 1/8" or "0" zero recording and not communicated
OEM Brush maintenance check sheet acquired actual practise is defecient
Brush wear trends and documented and reviewed (unit 1 & unit 7) Wear rate data 2008 to 2016 for brushes indicates that unit 7 brushes need to be replaced at a rate greater than every two years which is the existing maintenance interval
Electrical: performing annual PM and measuring brushes used 1/2" of acceptable brush left rather than 1/8" of wear on the inspection sheet. Knowing that 1/8" of wear wasn't correct and didn't address to correct measurement on the inspection sheet.
we have 3" brushes and no history on when brush lengths were changed
Cancelling semi annual inspection -difficult to get unit in winter months for -major inspections semi annual inspection too frequent -decision made many years ago could not find emplyee that was here at the time
Churchill Falls Checklist Received More Frequent visual inspections by Operations (daily)
Maintenance Check Sheet Shows replaced brushes with less than 1/8" remaining need to change to 1/2" remaining
No way of showing if brush quality changed
Replace worn brushes at length of 1/2" - PM6
Brush Inspection Unit 5 - 2017 found brushes with nothing left and indicated by zero Unit 6 - 2017 all brushes replaced 2016 - four brushes replaced
PM9- Six Year Inspection
2015 Replaced Slip Ring
2015 All New Brushes (40)
Document ? 2016 PM9 Brush Inspection
Old Slip Ring - Brass New Slip ring - stainless steel no change in brush wear
CEA CCOS Generation committee/CEATI HPLIG group Posted question on brush gear failures and what information is available
2
Replacemnet worn brush length 1/8" -PM9
2014 attempt to install new slip ring
PM6 and PM9 inspections use same criteria in manned and unplanned plants. Daily/weekly criteria is different based on actual site visits (frequency of visits)
2015 new slip ring was installed after alignment checked
Brush gear PMs are only considered in PM6 & 9 checksheets -Conflicting infor. between PM6 & PM6 -Maintenance chets have been performed against obsolate PM check sheets. sometimes latest revision have not been used.
OM inspections are reviewed by person assigned to execute the work. Not reviewed or signed off by others levels. Change in reporting levels. Positions assigned to other roles and responsibility
Reports of similar failure at Holyrood, no report found
JD Edwards Inventory difference length description 4 1/2" vs actual 3"
Independent quailty control check to review of inspection sheets. Asset Management Procedures outline guidelines


Polarity Reversed Annual Requirement
Generator Failure
July 3 - Exciter Protection Operation
Unit Lockout Trip (unit offline)
3
Excessive Brush Wear
More brush wear on positive slip ring unit 7 - 2017 Failure
Get Churchill Falls slip ring brush fault Report - No Copy Available
Brushes - Unit 7 Wear and Contamination was the factor which started multiple brush failures
Add alarm on overcurrent condition on excitiation transformer
Communication between generating plants on issues, problems,or failures Share Investigation Share History
Failure Investigation into generating unit trips - need to complete
Document 2 Excitation Transformer overcurrent relay Instantaneous Trip (240A secondary) 3-phase (without neutral current)
Document 4 System sequence of events log
NO DFR New DFR required for BDE - not installed as per other generating plants
No system events around unit trips - no prior indication of events
Brush faults are not easy to detect but existing relaying did perform correctly
Existing DFR at BDE TS1 was not operational due to memory full - reguired to be checked reguarly
Indication of event 36 seconds before unit trip/lockout operator could not do anything at this time - not enough time to respond


Load Shedding resulting in 53,000 customer load loss (Activation of the UFLS)
4
Document 3
Power Advisory sent to PUB
Reports
2017-H-027-a
2017-H-028-a
Drop in System Frequency and Activation of UFLS affecting
Newfoundland Power,
NL Hydro, and CBPP
Maximum unit guideline policy
No issues guideline followed by ECC
Document 6
Art Bursey email
UFLS details and overview of event
UFLS operation reviewed and confirmed. no issues with customer load shedding - technically
NL Hydro customer load shed schedule - reduce all customer load shed blocks to 58.1 Hz due to other system faults
Customer Load Shedding due to under frequency
Without UFLS extreme low frequency would result that would cause customers damages and loss of customers. Note: Labrador Infeed with Mitigate customer load shedding
Maximum unit guideline policy uses UFLS to recover with limited customer load loss
Forced outage investigation reports - Surge and Trouble Report Procedures. Not consistent
Process restarted on May 1, 2017 Formal Process stopped in 2006
No accurate frequency recorder available on system


Customer Outage
Unit Testing
5
Unit Inspection Testing
Rotor
Stator
Exciter Testing
Excitation Transformer Testing
TTR/Winding/Doble
Testing of Excitation Transformer Relay
No problems identified - all tests good
ABB field Inspection Report
Document 8
Transformer test Results
DGA Test to be repeated
No problems or issues founds
Document ?
Excitation overcurrent relay test results - Test confirmed no issues with relay
Add additional alarm level to overcurrent relay for excitation transformer
Diffcult to detect brush faults
Testing was completed on exciter ground fault portection - no issues were found
Application of ANova to brush wear - Ern
Identifiy critial systems and their associated maintenance intervals to ensure reliable operation


Unit Repair
Slip Ring Repair
Re-install
Mechanical Testing
Unit On-Line
Testing
Unit released to
ECC for Normal
Operation
Brush Gear Inspection
Brushes
Slip Ring
New work method for
installation of slip ring and
brushes after replacement
Dave Cole
Inspection Report on
Brush gear
Document 10
Mapping of brush gear
damage - Bob Woodman
6

APPENDIX B – Mapping Report into Slip (Collector) Ring Failure

Unit 7 Collector Mapping:

This document is a description of the collector slip ring and brush assemble after the July 3rd, 2017 failure.
The unit was in service for a little under a year since the last PM inspection was performed on the unit.
During the 2016 PM9 outage, the brushes were inspected, an 11 of 20 brushes on the top ring were replaced due to wear, and all brushes on the bottom ring were well within tolerance and were reused.
Metal filings found in the pit were removed prior to this inspection to perform mapping.

Top ring (currently –ve)
Only 1 of the 20 brushes in service is boarder line with the tolerance. All others exceed tolerance by a large margin. The level of carbon dust on the brush ring is typical for this duration of operation since the last maintenance. There are no obvious signs of heat damage to this ring or the associated brush components. The overall condition of the top ring is excellent. The surface is smooth with no signs of irregular wear. This condition is exactly what one would hope to find during the annual PM.

Bottom ring (currently +ve):

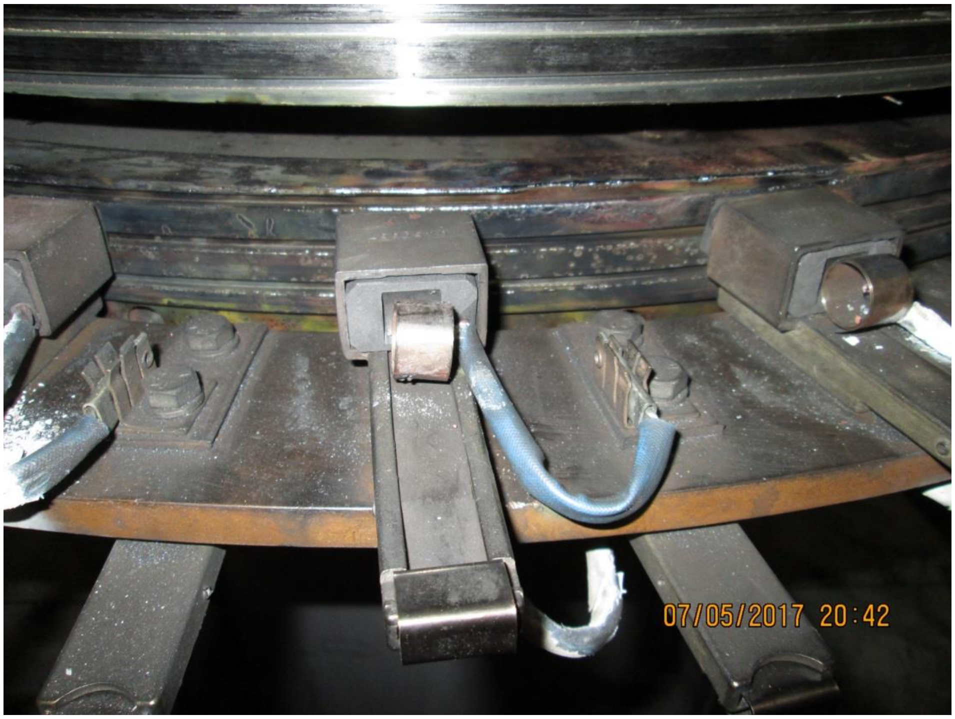
- There are signs of excessive overheating on the full profile of the ring.
- There are no signs of irregular wear prior to the failure – lack of gouging, etc.
- The surface is rough (fine pitting / splatter) around the entire circumference on both the upper and lower sections.

Each ring contains two rows of 10 brushes. Based on the sketch that shows orientation of the brushes for the lower ring the following observations were made for each brush / holder (T = top, and B = bottom):

T1: The brush holder has pits / splatter on the top, and some metal loss on the surface adjacent to the ring (all signs of arching and overheating). The brush face shows signs of abnormal carbon loss. About 20% was making poor contact, and the rest was not making any contact with the ring. The brush wear is at the threshold for replacement. The pigtail is not damaged. (Pictures 2 and 3)

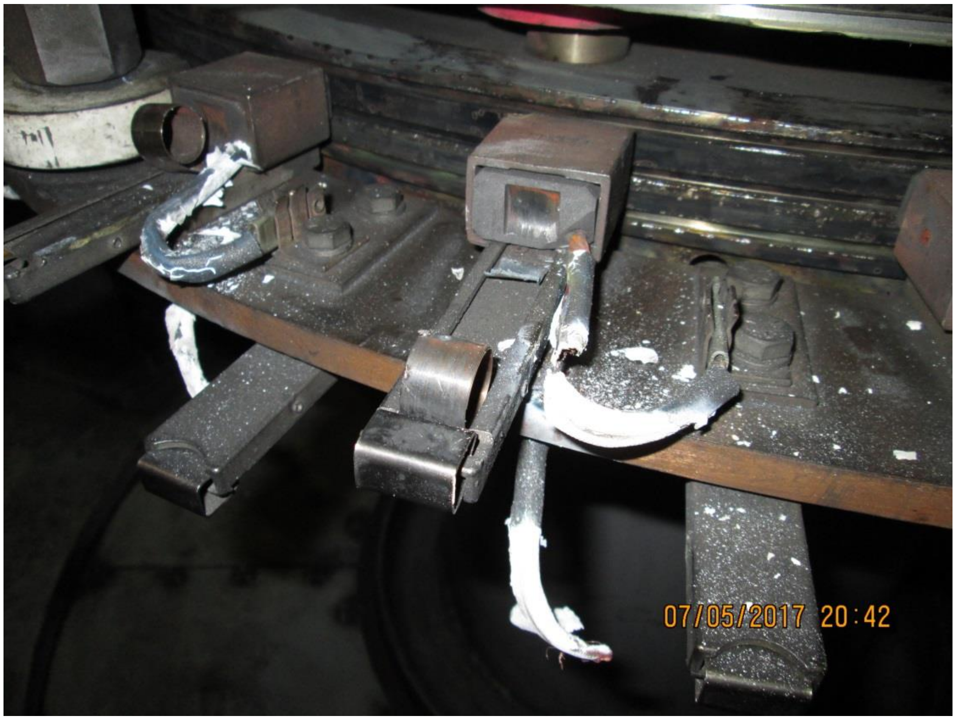
T2: The brush holder has some metal loss on the surface adjacent to the ring. The brush wear is a little below the threshold for replacement. The pigtail is melted off at the brush connection. (Picture 4)

T3: The brush wear is at the threshold for replacement. The pigtail is melted off at the brush connection. (Picture 5)



T4: There is minor damage to the brush holder. The brush wear is at the threshold for replacement. The pigtail is melted off in the middle (between the brush and the connector). (Picture 6)

T5: There is arcing damage on one corner of the brush holder. The brush wear is at the threshold for replacement. The pigtail is melted off. The spring is broken. (Picture 7)



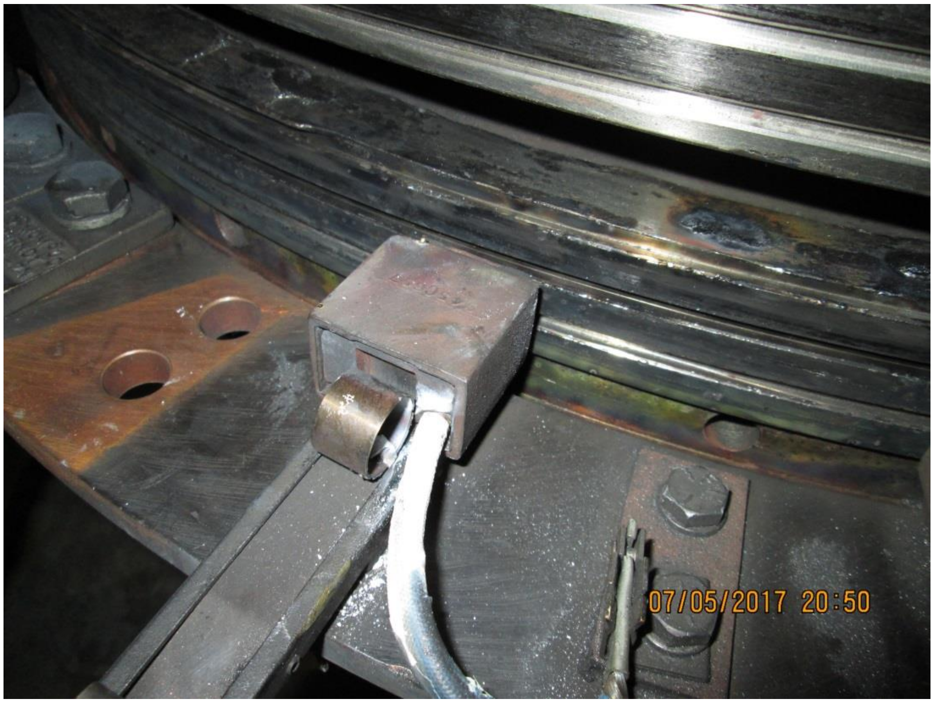
T6: The brush wear is at the threshold for replacement. The pigtail insulation is severely damaged, and the copper is intact. There is no spring tension. (Picture 1)

T7: The brush holder sides have holes melted in them, and some metal loss on the surface adjacent to the ring. The brush wear is at the threshold for replacement. The pigtail is melted off. (Pictures 8, 9 & 10)

T8: The brush holder has pits / splatter on the top, and some metal loss on the surface adjacent to the ring. The brush wear is at the threshold for replacement. The pigtail is melted off in the middle (between the brush and the connector). The spring is broken. (Picture 11)

T9: The brush holder has pits / splatter on the top. The brush wear is at the threshold for replacement. The pigtail is melted off in the middle. There is full (poor) contact at the brush face. (Picture 12)

T10: The brush holder has a small melt area on one top corner. The brush wear is at the threshold for replacement. The pigtail insulation is melted through and copper is intact. (Picture 13)

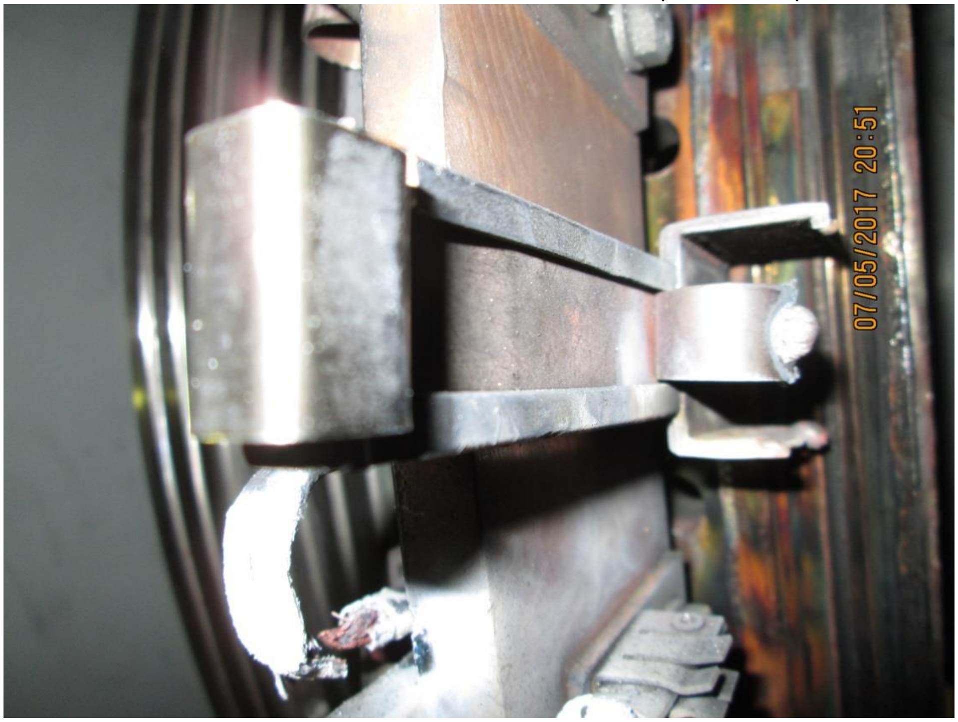


B1: Heavy heat damage to brush, pigtail and holder. The brush wear is less than the threshold for replacement. (Picture 14)

B2: The brush holder melted and the brush fell out. (Picture 15)

B3: Heavy heat damage to brush, pigtail and holder. The brush wear is less than the threshold for replacement. (Picture 16)

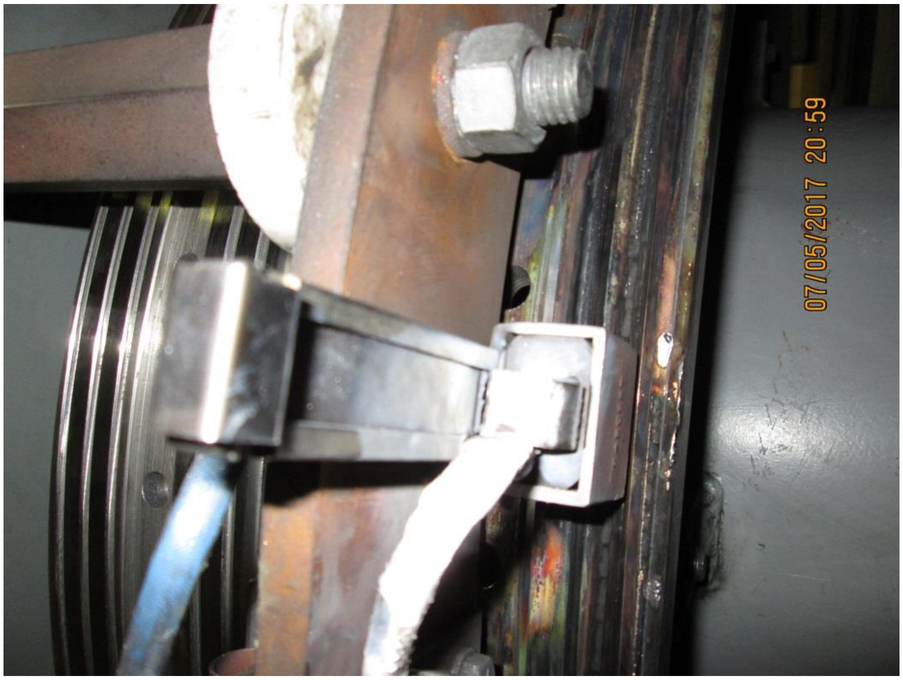
B4: The brush holder melted and the brush fell out. (Picture 17)



B5: Heavy heat damage to brush, pigtail and holder. The brush wear is less than the threshold for replacement. (Picture 18)

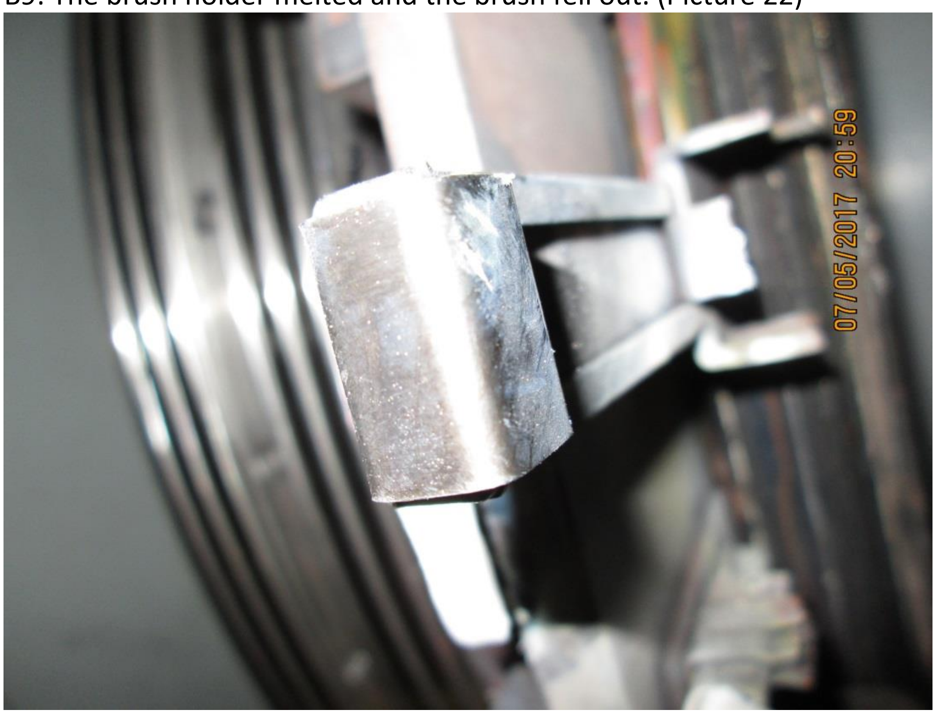
B6: Heavy heat damage to brush, pigtail and holder. The brush wear is less than the threshold for replacement. (Picture 19)

B7: Heavy heat damage to brush, pigtail and holder. The brush wear is less than the threshold for replacement. (Picture 20)



B8: The brush holder melted and the brush fell out. (Picture 21)

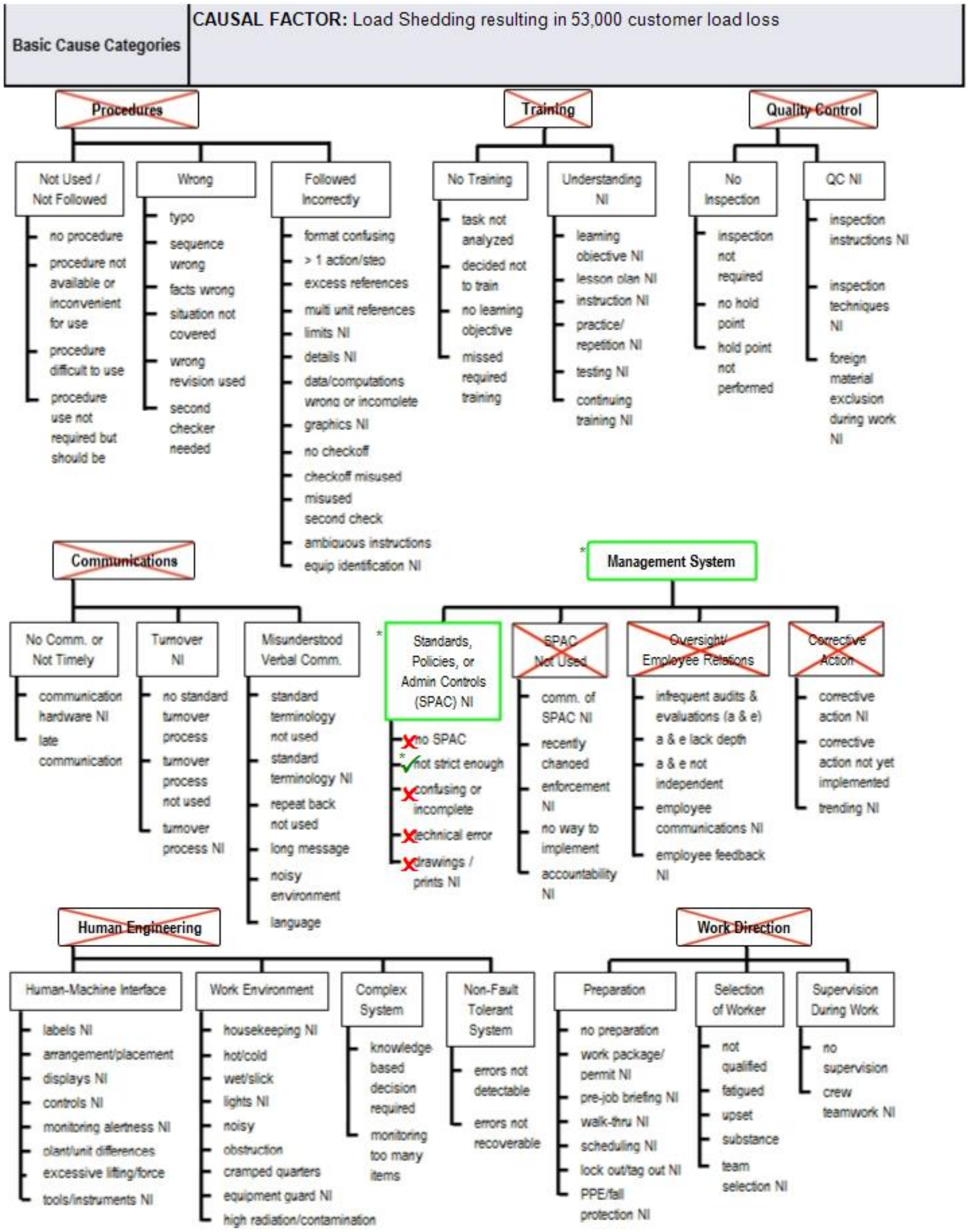
B9: The brush holder melted and the brush fell out. (Picture 22)



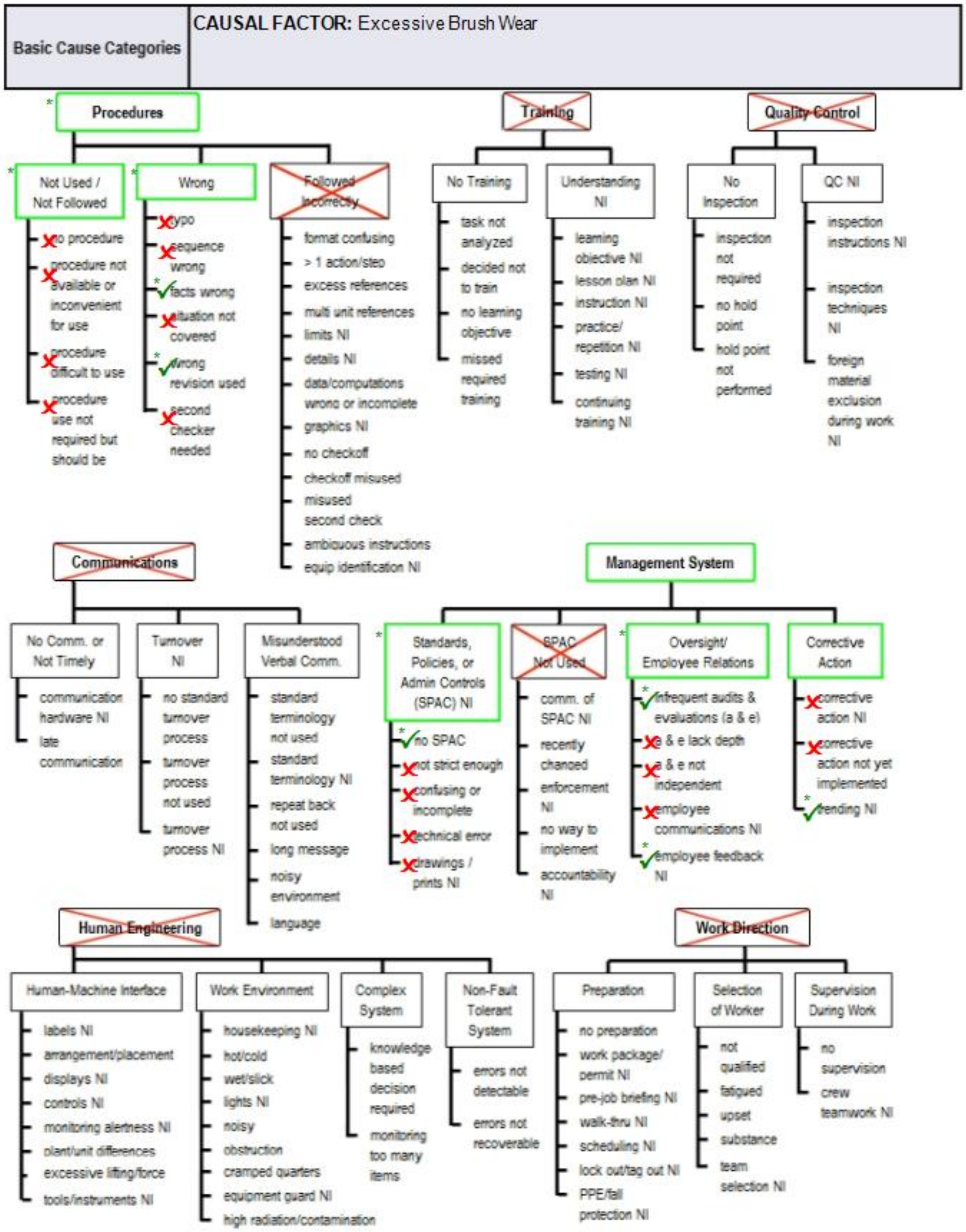
B10: The brush holder melted and the brush fell out. (Picture 23)

The insulator near the cable connection to the slip ring has splatter damage. (Picture 24)

APPENDIX C – Causal Factor –
Load Shedding resulting in 53, 000 customer load loss


Basic Cause Categories
CAUSAL FACTOR: Load Shedding resulting in 53,000 customer load loss
Procedures
Not Used / Not Followed
no procedure
procedure not available or inconvenient for use
procedure difficult to use
procedure use not required but should be
Wrong
typo
sequence wrong
facts wrong
situation not covered
wrong revision used
second checker needed
Followed Incorrectly
format confusing
> 1 action/step
excess references
multi unit references
limits NI
details NI
data/computations wrong or incomplete
graphics NI
no checkoff
checkoff misused
misused second check
ambiguous instructions
equip identification NI
Training
No Training
task not analyzed
decided not to train
no learning objective
missed required training
Understanding NI
learning objective NI
lesson plan NI
instruction NI
practice/ repetition NI
testing NI
continuing training NI
Quality Control
No Inspection
inspection not required
no hold point
hold point not performed
QC NI
inspection instructions NI
inspection techniques NI
foreign material exclusion during work NI
Communications
No Comm. or Not Timely
communication hardware NI
late communication
Turnover NI
no standard turnover process
turnover process not used
turnover process NI
Misunderstood Verbal Comm.
standard terminology not used
standard terminology NI
repeat back not used
long message
noisy environment
language
Management System
Standards, Policies, or Admin Controls (SPAC) NI
no SPAC
not strict enough
confusing or incomplete
technical error
drawings / prints NI
SPAC Not Used
comm. of SPAC NI
recently changed
enforcement NI
no way to implement
accountability NI
Oversight/ Employee Relations
infrequent audits & evaluations (a & e)
a & e lack depth
a & e not independent
employee communications NI
employee feedback NI
Corrective Action
corrective action NI
corrective action not yet implemented
trending NI
Human Engineering
Human-Machine Interface
labels NI
arrangement/placement
displays NI
controls NI
monitoring alertness NI
plant/unit differences
excessive lifting/force
tools/instruments NI
Work Environment
housekeeping NI
hot/cold
wet/slick
lights NI
noisy
obstruction
cramped quarters
equipment guard NI
high radiation/contamination
Complex System
knowledge based decision required
monitoring too many items
Non-Fault Tolerant System
errors not detectable
errors not recoverable
Work Direction
Preparation
no preparation
work package/ permit NI
pre-job briefing NI
walk-thru NI
scheduling NI
lock out/tag out NI
PPE/fall protection NI
Selection of Worker
not qualified
fatigued
upset
substance
team selection NI
Supervision During Work
no supervision
crew teamwork NI

APPENDIX D – Causal Factor – Excessive Brush Wear


Basic Cause Categories
CAUSAL FACTOR: Excessive Brush Wear
Procedures
Not Used / Not Followed
no procedure
procedure not available or inconvenient for use
procedure difficult to use
procedure use not required but should be
Wrong
typo
sequence wrong
facts wrong
situation not covered
wrong revision used
second checker needed
Followed Incorrectly
format confusing
> 1 action/step
excess references
multi unit references
limits NI
details NI
data/computations wrong or incomplete
graphics NI
no checkoff
checkoff misused
misused second check
ambiguous instructions
equip identification NI
Training
No Training
task not analyzed
decided not to train
no learning objective
missed required training
Understanding NI
learning objective NI
lesson plan NI
instruction NI
practice/ repetition NI
testing NI
continuing training NI
Quality Control
No Inspection
inspection not required
no hold point
hold point not performed
QC NI
inspection instructions NI
inspection techniques NI
foreign material exclusion during work NI
Communications
No Comm. or Not Timely
communication hardware NI
late communication
Turnover NI
no standard turnover process
turnover process not used
turnover process NI
Misunderstood Verbal Comm.
standard terminology not used
standard terminology NI
repeat back not used
long message
noisy environment
language
Management System
Standards, Policies, or Admin Controls (SPAC) NI
no SPAC
not strict enough
confusing or incomplete
technical error
drawings / prints NI
SPAC Not Used
comm. of SPAC NI
recently changed
enforcement NI
no way to implement
accountability NI
Oversight/ Employee Relations
infrequent audits & evaluations (a & e)
a & e lack depth
a & e not independent
employee communications NI
employee feedback NI
Corrective Action
corrective action NI
corrective action not yet implemented
trending NI
Human Engineering
Human-Machine Interface
labels NI
arrangement/placement
displays NI
controls NI
monitoring alertness NI
plant/unit differences
excessive lifting/force
tools/instruments NI
Work Environment
housekeeping NI
hot/cold
wet/slick
lights NI
noisy
obstruction
cramped quarters
equipment guard NI
high radiation/contamination
Complex System
knowledge based decision required
monitoring too many items
Non-Fault Tolerant System
errors not detectable
errors not recoverable
Work Direction
Preparation
no preparation
work package/ permit NI
pre-job briefing NI
walk-thru NI
scheduling NI
lock out/tag out NI
PPE/fall protection NI
Selection of Worker
not qualified
fatigued
upset
substance
team selection NI
Supervision During Work
no supervision
crew teamwork NI

APPENDIX E – Testing Report Notes on Unit 7

An inspection of the protection panels determined the unit had locked out after the operation of the instantaneous over current protection (50RT) on the excitation transformer. This led to the initial thought that an exciter issue had occurred and the damage was the result of an exciter problem. A protection and control technologist from Hydro Generation reviewed the event log in the exciter and determined there was no trip initialized from the exciter and no alarms indicating an exciter fault. This was confirmed by an in depth review of the complete event log from the exciter by an ABB engineer who arrived at Bay d'Espoir on July 6. The ABB engineer with site assistance from Engineering Services reviewed the exciter operation. This inspection determined there were no problems or components malfunctions with the excitation system[16].

The rectifying transformer overcurrent relay (50RT) was tested by TRO Central Protection and Control department and was found to be in good working order. There was no issue with its operation for this fault and the relay settings were confirmed to be as per commissioning report and setting letter. Engineering Services had reviewed the relay settings and confirmed the setting was appropriate for this application.

The exciter's rectifying transformer was inspected and tested by Hydro Generation and TRO Central personnel who determined no abnormal conditions were found.

Hydro Generation personnel checked all external connections in the exciter and rectifying transformer for damage or loose connections which could be providing a false indication of a fault to the protection. No problems were found and all connections were tight.

Additional testing was completed on the unit 7 generator which included the following:

1. The rotor winding insulation resistance test and results were acceptable.
2. The rotor winding resistance test results and were acceptable.
3. The rotor winding impedance test results and were acceptable.
4. The stator winding insulation resistance test and results were acceptable.

The following listing is action items which were completed to investigate the unit tripping.

[16] The field service report from ABB is available in Appendix V.

Listing of Action Items which were completed.	
No.	**Action Item(s)**
1	Visual inspection of rotor and stator
2	Megger test on rotor
3	Conduct pole drop test
4	Inspection of Isolated Phase Bus was conducted and megger tested
5	Test annunciator circuits associated with generator and exciter
6	Exciter was fully tested and fault log was retrieved and reviewed
7	Conduct a PI test on the stator to look for a fault to ground.
8	Excitation transformer – turn to turn ratio and winding and doble testing
9	Over current relay checked on excitation transformer
10	Check grounding brush assembly
11	Bridge test to test the continuity and resistance of the stator windings. From the terminals, test A-B, B-C, and C-A. The resistance values should be pretty much the same.
12	Testing of ground fault relay in exciter
13	Complete a mapping of brush gear failure
14	Review vibration readings, temperature's during shutdown
15	Resistance test of the stator winding
16	Further inspection of the brush gear assembly
17	Damaged slip ring to be removed and shipped to St. John's repair shop
18	Slip ring to arrive at Bay d' Espoir for inspection
19	Inspection of the unit for any signs of other damage not presently identified.
20	Unit covers to be installed before the re-installation of the rebuild slip ring and brush gear

21	Oil sample to be taken from excitation transformer
22	Mechanical start-up of unit and testing
23	Monitoring of excitation transformer for the first few days of operated after the unit has been released for service

APPENDIX F – Guideline for Unit Maximum Loading

newfoundland labrador hydro
a nalcor energy company

SYSTEM OPERATING INSTRUCTION

STATION:	General	**Inst. No.**	T-068
TITLE:	Guideline for Unit Maximum Loading	**Page** 1	**of** 2

Introduction

The underfrequency load shedding scheme provides loads which will trip when a large generator trips on the system. In this way the load and generation are matched and the system remains stable. Once additional generation is brought on line the load can be restored.

Under light loading conditions and high loading on the units at Holyrood or Unit 7 at Bay d' Espoir there is a risk of having insufficient load available to cover-off the loss of one of these units. In the extreme light load condition this could result in the system stalling. To minimize the probability of this occurring it is recommended that the largest units on the system be limited in their maximum output depending on the total system load. The total system load is indicative of the amount of inertia and the amount of load available for load shedding.

Procedure

The attached guideline shall be used to determine maximum loading for the largest unit connected to the system for varying system loads and industrial load availability. Following this guideline will prevent loads set to trip at 58.0 Hz from tripping if the largest unit trips. The loss of the largest unit when following this guideline will result in the frequency staying above 58 Hz. In this way customer load interruptions are minimized on loss of large generating units.

The following table shall be followed whenever possible with consideration of unit availability and system security.

newfoundland labrador hydro
a nalcor energy company

SYSTEM OPERATING INSTRUCTION

STATION: General		**Inst. No.**	T-068
TITLE: Guideline for Unit Maximum Loading		**Page** 2	**of** 2

System Generation	Maximum Unit Loading
816	175
794	170
772	167
750	162
728	157
706	152
684	146
662	142
640	137
618	134
596	130
574	124
552	120
530	115
508	111
486	106
464	101
442	97
420	92
398	87
376	83
354	78
332	73

REVISION HISTORY

Version Number	Date	Description of Change
0	1996-02-08	Original Issue
3	2011-08-31	Replace table

PREPARED: Bob Butler

APPROVED:

APPENDIX G – System Sequence of Events - Partial

DATE		ORIGIN	DESCRIPTION	EVENT	VALUE
2017/07/03	17:39:21.943	Bay d'Espoir PH2	G7 Voltage Reg Ready to Transfer	OFF	SOE
2017/07/03	17:39:22.111	Bay d'Espoir PH2	G7 Voltage Reg Ready to Transfer	ON	SOE
2017/07/03	17:39:22.174	Bay d'Espoir PH2	G7 Excitation Fault	ALARM	SOE
2017/07/03	17:39:22.195	Bay d'Espoir PH2	G7 Excitation Fault	NORMAL	SOE
2017/07/03	17:39:23.323	Bay d'Espoir PH2	G7 Voltage Reg Ready to Transfer	OFF	SOE
2017/07/03	17:39:24.832	Bay d'Espoir PH2	G7 Voltage Reg Ready to Transfer	ON	SOE
2017/07/03	17:39:33.494	Bay d'Espoir PH2	G7 Excitation Fault	ALARM	SOE
2017/07/03	17:39:33.595	Bay d'Espoir PH2	G7 Excitation Fault	NORMAL	SOE
2017/07/03	17:39:33.674	Bay d'Espoir PH2	G7 Excitation Fault	ALARM	SOE
2017/07/03	17:39:33.695	Bay d'Espoir PH2	G7 Excitation Fault	NORMAL	SOE
2017/07/03	17:39:33.854	Bay d'Espoir PH2	G7 Excitation Fault	ALARM	SOE
2017/07/03	17:39:33.995	Bay d'Espoir PH2	G7 Excitation Fault	NORMAL	SOE
2017/07/03	17:39:34.034	Bay d'Espoir PH2	G7 Excitation Fault	ALARM	SOE
2017/07/03	17:39:34.055	Bay d'Espoir PH2	G7 Excitation Fault	NORMAL	SOE
2017/07/03	17:39:35.123	Bay d'Espoir PH2	G7 Voltage Reg Ready to Transfer	OFF	SOE
2017/07/03	17:39:35.253	Bay d'Espoir PH2	G7 Voltage Reg Ready to Transfer	ON	SOE
2017/07/03	17:39:37.074	Bay d'Espoir PH2	G7 Excitation Fault	ALARM	SOE
2017/07/03	17:39:37.175	Bay d'Espoir PH2	G7 Excitation Fault	NORMAL	SOE
2017/07/03	17:39:37.354	Bay d'Espoir PH2	G7 Excitation Fault	ALARM	SOE
2017/07/03	17:39:37.375	Bay d'Espoir PH2	G7 Excitation Fault	NORMAL	SOE
2017/07/03	17:39:37.654	Bay d'Espoir PH2	G7 Excitation Fault	ALARM	SOE
2017/07/03	17:39:37.675	Bay d'Espoir PH2	G7 Excitation Fault	NORMAL	SOE
2017/07/03	17:39:37.894	Bay d'Espoir PH2	G7 Excitation Fault	ALARM	SOE
2017/07/03	17:39:37.955	Bay d'Espoir PH2	G7 Excitation Fault	NORMAL	SOE
2017/07/03	17:39:38.843	Bay d'Espoir PH2	G7 Voltage Reg Ready to Transfer	OFF	SOE
2017/07/03	17:39:39.192	Bay d'Espoir PH2	G7 Voltage Reg Ready to Transfer	ON	SOE
2017/07/03	17:39:40.574	Bay d'Espoir PH2	G7 Excitation Fault	ALARM	SOE
2017/07/03	17:39:40.595	Bay d'Espoir PH2	G7 Excitation Fault	NORMAL	SOE
2017/07/03	17:39:40.674	Bay d'Espoir PH2	G7 Excitation Fault	ALARM	SOE
2017/07/03	17:39:40.815	Bay d'Espoir PH2	G7 Excitation Fault	NORMAL	SOE
2017/07/03	17:39:41.968	Bay d'Espoir PH2	G7 Voltage Reg Ready to Transfer	OFF	SOE
2017/07/03	17:39:42.577	Bay d'Espoir PH2	G7 Voltage Reg Ready to Transfer	ON	SOE
2017/07/03	17:39:44.074	Bay d'Espoir PH2	G7 Excitation Fault	ALARM	SOE
2017/07/03	17:39:44.095	Bay d'Espoir PH2	G7 Excitation Fault	NORMAL	SOE
2017/07/03	17:39:44.354	Bay d'Espoir PH2	G7 Excitation Fault	ALARM	SOE
2017/07/03	17:39:44.415	Bay d'Espoir PH2	G7 Excitation Fault	NORMAL	SOE
2017/07/03	17:39:44.494	Bay d'Espoir PH2	G7 Excitation Fault	ALARM	SOE
2017/07/03	17:39:44.515	Bay d'Espoir PH2	G7 Excitation Fault	NORMAL	SOE
2017/07/03	17:39:44.594	Bay d'Espoir PH2	G7 Excitation Fault	ALARM	SOE
2017/07/03	17:39:44.615	Bay d'Espoir PH2	G7 Excitation Fault	NORMAL	SOE
2017/07/03	17:39:44.694	Bay d'Espoir PH2	G7 Excitation Fault	ALARM	SOE
2017/07/03	17:39:44.915	Bay d'Espoir PH2	G7 Excitation Fault	NORMAL	SOE
2017/07/03	17:39:44.994	Bay d'Espoir PH2	G7 Excitation Fault	ALARM	SOE
2017/07/03	17:39:45.295	Bay d'Espoir PH2	G7 Excitation Fault	NORMAL	SOE
2017/07/03	17:39:45.374	Bay d'Espoir PH2	G7 Excitation Fault	ALARM	SOE
2017/07/03	17:39:45.475	Bay d'Espoir PH2	G7 Excitation Fault	NORMAL	SOE
2017/07/03	17:39:45.574	Bay d'Espoir PH2	G7 Excitation Fault	ALARM	SOE
2017/07/03	17:39:45.595	Bay d'Espoir PH2	G7 Excitation Fault	NORMAL	SOE

DATE		ORIGIN	DESCRIPTION	EVENT	VALUE
2017/07/03	17:39:46.000	Bay d'Espoir PH2	G7 kV kV	LOW LIMIT 1 EXCEEDED	12.9
2017/07/03	17:39:46.853	Bay d'Espoir PH2	G7 Voltage Reg Ready to Transfer	OFF	SOE
2017/07/03	17:39:47.702	Bay d'Espoir PH2	G7 Voltage Reg Ready to Transfer	ON	SOE
2017/07/03	17:39:48.000	Bay d'Espoir PH2	G7 kV kV	RETURNED TO NORMAL	13.5
2017/07/03	17:39:50.233	Bay d'Espoir PH2	G7 Voltage Reg Ready to Transfer	OFF	SOE
2017/07/03	17:39:54.262	Bay d'Espoir PH2	G7 Voltage Reg Ready to Transfer	ON	SOE
2017/07/03	17:39:58.404	Bay d'Espoir PH2	G7 Excitation Fault	ALARM	SOE
2017/07/03	17:39:58.407	Bay d'Espoir PH2	86-G7/T7	OPERATED	SOE
2017/07/03	17:39:58.418	Bay d'Espoir GS	T-B11L06	OPERATED	SOE
2017/07/03	17:39:58.424	Bay d'Espoir PH2	PH2 Station Service	ALARM	SOE
2017/07/03	17:39:58.430	Bay d'Espoir PH2	G7 Electrical Fault	ALARM	SOE
2017/07/03	17:39:58.437	Bay d'Espoir GS	B11L06-3 PH.	OPEN	SOE
2017/07/03	17:39:58.443	Bay d'Espoir PH2	G7 Run	OFF	SOE
2017/07/03	17:39:58.451	Bay d'Espoir GS	B11L06	OPEN	SOE
2017/07/03	17:39:58.453	Bay d'Espoir GS	B10B11	OPEN	SOE

HATCH

Newfoundland and Labrador Hydro

Final Report

For

Repair and Failure Investigation

H356043-00000-240-230-0003
Rev. 0
March 29, 2018

Newfoundland and Labrador Hydro

Final Report

For

Repair and Failure Investigation

H356043-00000-240-230-0003
Rev. 0
March 29, 2018

Repair and Failure Investigation Final Report

H356043-00000-240-230-0003

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GREG SAUNDERS
SIGNATURE
29/03/2018
DATE
NEWFOUNDLAND & LABRADOR

2018-03-29	0	Approved for Use	M. Pyne	S. Bhan	G. Saunders
DATE	**REV.**	**STATUS**	**PREPARED BY**	**CHECKED BY**	**APPROVED BY**

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1. Executive Summary

A third rupture of Penstock No. 1 at Bay d'Espoir (BDE) occurred on November 4, 2017. The rupture occurred in the form of a 2' long crack just below the crack that was repaired only 14 months earlier (September 2016) in Can 35.

In general, the penstock cans are approximately 9' long; each can is fabricated from two steel plates rolled to a semi-cylindrical shape that are welded together longitudinally to form one can. Cans are numbered starting from Can 1 at the manhole, located approximately 1,050' from the intake, positive numbers towards the intake and negative numbers towards the surge tank, see Figure 4-2 and Figure 4-3.

The first crack occurred in the adjacent can (downstream, Can 34) in May 2016. This crack also occurred at the longitudinal weld on the north side of the penstock. All three ruptures have occurred in the upper section of the penstock which is fabricated out of 7/16" thick ASTM A285 Gr. C carbon steel plate.

Hatch mobilized a team to assist Newfoundland and Labrador Hydro (Hydro) in the repair and commissioning/testing of the penstock. The penstock was inspected visually and laser surveyed. Hatch designed a repair for the ruptured penstock which involved removal of a longitudinal strip of the penstock can with the crack in the middle and welding in place a 1/2" thick pre-rolled plate. Similarly, the repaired weld (May 2016) on Can 34 was removed as a precaution and a new pre-rolled plate welded in place. To reinforce the new repaired area and the one from May 2016, reinforcing plates (8' 6" radius, 1/2" thick) were welded on the exterior of Cans 33, 34 (ruptured in 2016), Can 35 (ruptured in 2016 and 2017) and Can 36. These plates were then welded to each other to operate as one large reinforcement over the entire area. Figure 1-1 and Figure 1-2 show the rupture area before and after repair, respectively.

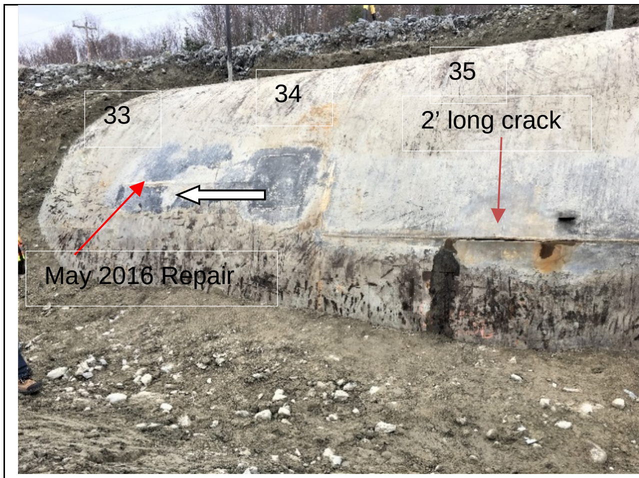


Figure 1-1: Failure Location Can 35 - Backfill Removed	**Figure 1-2: Strain Gauges & Wiring**

A metallurgical analysis of the failed section confirmed that the latest rupture in Can 35 initiated at the toe of the 2016 repair weld and then propagated into the parent plate material in an orientation parallel to the weld. Extensive material tests did not indicate any defects in plate material or the welds.

During the original repairs in September 2016 on Penstock No.1, defects found in many longitudinal seams on the inside lead to the repair of all 346 internal weld seams (approximately 1,500' of the total 3,900' length of penstock), from the intake to Can -44. All repaired cans (approximately 40% of the total penstock) were inspected visually and with magnetic particle examination, prior to return to service.

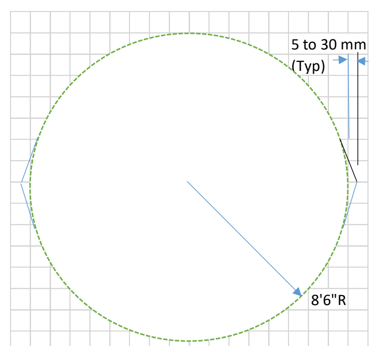
During the repair of the latest penstock rupture in November 2017, the majority of the longitudinal welds inside the penstock, from the intake to the surge tank (approximately 2272'or 690 m of the total 3,900' (1190 m) length of penstock), underwent Non-Destructive Testing (NDT) utilizing Magnetic Particle Testing (MT). The 2017 NDT extended beyond the examination completed in 2016 and utilized the same MT inspection method. Twenty-nine (29) of the 346 seams (8.4%) repaired previously in 2016 exhibited defects (potential crack initiation), within 14 months of the previous refurbishment (this includes the two ruptured seams). Two (2) new seams with cracks were discovered beyond the 2016 refurbished cans, for a total of 31 seams. Any defects or cracks found during this inspection (29 longitudinal seams excluding the ruptured welds that were removed and replaced) were repaired and a 22" wide 9' long 1/2" thick rolled reinforcing plate was welded on the inside over the top of the refurbished longitudinal welds.

To assist in determining the root cause of the penstock ruptures, strain gauges were installed inside and outside on the already exposed sections of the repaired penstock (Cans 33-36) and another upstream location (Can 65). Pressure transducers were also installed to monitor pressure inside the penstock at Cans 33 and 65. The exposed sections of the penstock with external strain gauges were backfilled and additional backfill was placed over approximately 328' (100 m) of penstock length 164' (50 m) upstream and 164' (50 m) downstream from Can 33). The additional backfill was placed to a higher level (2' or 600 mm) and in a more symmetrical configuration as was recommended by Hatch. The existing backfill profiles (original backfill design) were unsymmetrical and had lesser overburden (1' or 300 mm), and therefore it was more susceptible to sloughing and preferential deflection of the penstock towards the north side.

The instrumentation was monitored during filling of the repaired penstock and during a planned part-load rejection test of Unit No. 2 which took place on December 8, 2017. Data was collected for nearly two months after unit testing and compared to the data collected from unit testing. Hatch has carried out a detailed analysis of the measured data and also carried out a finite element (FE) analysis of the penstock geometry interaction with the backfill.

The investigations to-date indicate that the latest rupture was most likely caused by a combination of the following factors:

1. High residual stress due to re-welding of the ruptured seam under high pre-load used to bring the two edges of the ruptured joint together in September 2016.
2. High localized bending stresses under internal pressure (measured and verified by FE modeling) due to the non-circular shell geometry at the longitudinal weld seam from original fabrication ("peaking"- due to insufficient plate rolling radius at start and end resulting in deviation of surface at the seam from a smooth arc; exaggerated illustration right).



Fabrication Flaw at the Longitudinal Welds

3. Fatigue caused by high-cycle low-amplitude stresses due to pressure fluctuations in the penstock transmitted from the turbine. The pressure fluctuations introduce cyclic stresses in the penstock shell in addition to the stresses due to internal pressure, further intensified by peaking at the weld seam. The surge pressures transmitted up the penstock have a varying amplitude depending on the flow rate at the associated generator output. The source of surge pressures is predominantly the draft tube flow instability inherent in these units during normal operation. The pressure fluctuations are more severe during part-load or "Rough Zone" operation. Units No. 1 and No. 2 have a

"Rough Zone" between 25 and 45 MW. Extended operation of the units in the Rough Zone over the last five years are likely to have accelerated fatigue in the weld seams. Opening and closing of the spherical valves and the wicket gates during unit starts and stops, as well as load rejections are additional sources of pressure surges in the penstock, but likely minor contributors to fatigue due to the fewer number of cycles.

4. The as-built backfill was prone to sloughing due to insufficient depth of overburden (1' on top) and the shape of the backfill was unsymmetrical leading to unsymmetrical deformation of the penstock shell when empty.

Hatch believes that the risk of failure of the repaired Penstock No. 1 from now until the next inspection (summer 2018) is relatively low. However, it should be noted that very high stresses were measured in the vicinity of the welds under normal operation and that the penstock has accumulated damage over its life time in other areas not detectable by the inspections carried out.

Several alternatives for a long-term solution to achieve safe and reliable operation of the penstock were examined. Replacement of the entire length of the affected penstock (between the intake and the surge tank) is the most reliable solution and is also most likely the most expensive solution. The least cost solution is to continue inspecting the penstock annually and repair any defects as they occur. There are several solutions in between with lower costs but higher risks. It is recommended that a separate study should be carried out to evaluate the relative costs and benefits of different long-term solutions. Until then we recommend the following:

Penstock No. 1, Unit No. 1 and Unit No. 2 operation may be continued with the following considerations:

- Operation of the units in the rough zones should be limited to that absolutely necessary. Additionally, transitioning through the rough zone should be as quickly as practical; there is no limit on the maximum load that the units can be operated at.
- Walk the penstock once a day and after unusual pressure transients, such as load rejections, and monitor regularly by camera for evidence of leaks.
- Internal inspection of Penstock No. 1 during the summer of 2018 and determine inspection frequency based on findings.

Penstock No. 1 remedial work:

- Backfill and re-coating operations should be postponed until completion and evaluation of inspection summer 2018.

Inspection of Penstock No. 2 and Penstock No. 3 is also recommended since they are of similar design and vintage as Penstock No. 1.

2. Introduction

Hydro engaged Hatch's engineering services in response to a rupture in Penstock No. 1 at the Bay d'Espoir (BDE) hydroelectric generating station on November 4, 2017.

Hatch designed a repair solution and mobilized to oversee inspection and repairs. A test program was prepared to monitor pressure and stresses in the rupture area of the penstock. The penstock was placed back in service on December 8, 2017. An interim report was issued on December 21, 2017 and presented results of the site inspection, repair design and execution, testing, FE analysis and interpretation of the test measurements to-date. Since then further analysis of the test data has been carried out and used in a fatigue analysis.

The instrumentation installed on the penstock for the commissioning tests on December 8, 2017 continued to collect data after the tests until February 20, 2018 when the data acquisition system was returned to the National Research Council. Measurements taken over a six-week period showed insignificant change indicating that the penstock repair remains stable. Further analysis of the data during opening of the spherical valves on December 8, 2017 was analyzed to investigate potential contribution from this operation on the cause of penstock rupture.

Several alternatives for a long-term solution were examined at a preliminary level. This final report includes details of our investigation (also reported in the interim report), as well as further analysis of data including a fatigue analysis. Various alternatives considered for a long-term solution and recommendations are also presented. The recommendations include considerations for inspection and evaluation of Penstock No. 2 and Penstock No. 3.

3. Background

The BDE main powerhouse consists of six generating units fed from three penstocks. Penstock No.1 feeds Units No. 1 & No. 2, Penstock No. 2 feeds Unit No. 3 & No. 4 and Penstock No. 3 feeds Unit No. 5 & No. 6. Each penstock bifurcates near the powerhouse to feed water to two separate units through two spherical valves. Units No.1 & No. 2 along with Penstock No. 1 were built in 1967. Penstocks No. 2 & No. 3 were built in 1968 and 1969, respectively, and, based on project As Built Drawings, were thought to have identical designs to Penstock No. 1. However, there are two key differences that have been discovered during repairs, analysis, and investigation.

1. Penstock No. 1 design and as-built backfill depth on top (1 ft) is less than as-built backfill depth on Penstock No.2 (2 ft) and Penstock No. 3 (2 ft). This may cause Penstock No.1 to undergo larger deformation than the other penstocks during dewatering.
2. In 2016, during an inspection external stiffening rings (rolled angles, not shown on the design drawings) were discovered in the upper sections of Penstock No. 2. These rings may have been installed as construction and lifting aids for handling. It is unknown if Penstock No. 3 was also built with external ribs (none shown on design drawings).

Penstock No. 1 is approximately 3,900 feet long and is constructed from a series of carbon steel cans that vary in length depending on location, but in general the cans are approximately 9’ long. Each can consists of two rolled semi-cylindrical steel plates welded together longitudinally. There are no circumferential stiffener rings except in areas such as bends and concrete embedded sections. The penstock is supported on a prepared granular bedding and covered with backfill.

The penstock diameter varies from 17’ near the intake to 13’6” near the powerhouse, and the wall thickness varies from 7/16” near the intake to 1-7/16” near the powerhouse. The upper 1100 feet of the penstock steel conforms to ASTM A285 Gr. C and the remainder CSA G40.8 Gr. B. Cracks in longitudinal welds have been discovered in both ASTM A285 Gr. C and CSA G40.8 Gr. B sections. However, all the ruptures have occurred in the sections constructed of ASTM A285 Gr. C. All cracking the CSA G40.8 section have occurred in the sections fabricated with 7/16” plates.

The penstock sections are subject to varying internal pressure starting from 43.5’ of water (18.8 psi or 130 kPa) near the intake to 590’ (255.7 psi or 1,763 kPa) at the powerhouse under static hydraulic conditions.

During the era (1965-1966) in which Penstock No. 1 was constructed, plate rolling was generally accomplished utilizing a three-roll single pinch point roll. When rolling plates with this type of roller, the start and end of each plate will be flat (unless other techniques are used such as pre-bending or by cutting off the flat section). This causes the cross-section of cans at the longitudinal weld seams to appear as a cone rather than a circular arc, which is termed as “peaking” for the purpose of discussion in this report. The level of peaking is characterized by the radial gap between the longitudinal joint and the theoretical circular arc. Peaking (10 to 30 mm) was noted on all Cans inspected. Peaking is not normal in the fabrication of penstock shells today due to better plate rolling techniques. This discontinuity in the circular geometry at the longitudinal seam induces localized bending stresses under internal pressure (confirmed by FE modeling).

On May 21, 2016, BDE Penstock No. 1 was found to have a leak from a two-foot (600 mm) long rupture along a longitudinal weld seam in Can 34. The crack was repaired and the penstock was put back into service. On September 14, 2016, Penstock No. 1 experienced another longitudinal seam rupture in Can 35, approximately 16’ (5 m) upstream from the previous rupture in the adjacent can. The rupture was repaired by Hydro. Hatch was engaged on September 22, 2016, to assess the penstock, at which time it was discovered that nearly 2000 ft of interior weld in the upper section of the penstock showed erosion and deterioration with partial depth cracking. Hatch provided a refurbishment method and construction assistance during the repair work. The penstock was put back into service on November 30, 2016.

A third rupture was discovered on November 4, 2017. This rupture was on the same can just below the rupture that was last repaired (September 2016). Hydro immediately engaged the services of Hatch to assist in the inspection, repair and assessment of the penstock.

Upon completion of inspections in September 2016, it was confirmed that the majority of longitudinal weld joints from the intake down to Section 117 (Dwg.10830, approximately 3000’ of penstock length), had experienced a significant amount of weld metal loss due to corrosion. A total of three hundred and forty-six (346) longitudinal seam welds (3114’) in this section of the penstock were gouged out, repair welded and inspected before the penstock was put back in service.

The root cause analysis conducted by Hatch in 2016 concluded that the 2016 failures occurred most likely due to stress corrosion cracking resulting from the presence of high stresses at the corroded longitudinal welds and the corrosive environment resulting from the loss of internal penstock coating. The report also attributed the higher stresses to insufficient backfill on top of the penstock and high residual stresses induced during penstock fabrication.

4. Inspection

The latest penstock rupture on November 4, 2017 was inspected visually (Figure 1-1). The entire length of the affected can around the crack was cut and shipped to a metallurgical laboratory for metallurgical analysis and material testing (Figure 4-1). The majority of longitudinal welds on the interior of the penstock from the intake to the surge tank (2272' or 690 m) were inspected visually, by magnetic particle, and using laser survey. Laser survey of the interior of the penstock was used to determine the interior shape of the penstock and confirm the level of peaking present. Cracks or defects were discovered on twenty-nine (29) longitudinal welds out of 430 seams inspected. Twenty-seven (27) of these were on 2016 repairs and two (2) were on original welds. Including the 2 longitudinal weld seams from the ruptured portion of the penstock makes the total 31 repaired seams. A detailed inspection chart is shown on the following page that shows 2016 repairs, 2017 repairs, cleared cans, cans that exhibited new indications, and cans that exhibited extensive cracking in 2016. The backfill and settlement monitoring posts over the same length of penstock were surveyed and the data is presented.

None of the circumferential welds were inspected as no cracks were found in 2016 and these joints only have half the stress due to internal pressure as compared to the longitudinal joints.

Hatch investigated if there was any loss of support at the bottom of the failed cans and adjacent area by drilling through 3" couplings welded to the bottom of the penstock at four different longitudinal locations. The visual examination of the bedding below the penstock, and the laser survey of the penstock invert and external settlement monitoring posts showed insignificant bedding loss.

The penstock between the surge tank and the powerhouse was not inspected as no cracks were found in this section in 2016. The plate in these sections is thicker and the penstock diameter is smaller. Additionally, no significant weld seam corrosion was found during the 2016 inspections. Absence of peaking at the longitudinal welds in the penstock downstream of the surge tank should be confirmed at the next inspection.

Figure 4-1: Close-up View of the Rupture in Can 35 (in the Laboratory for Material Tests)

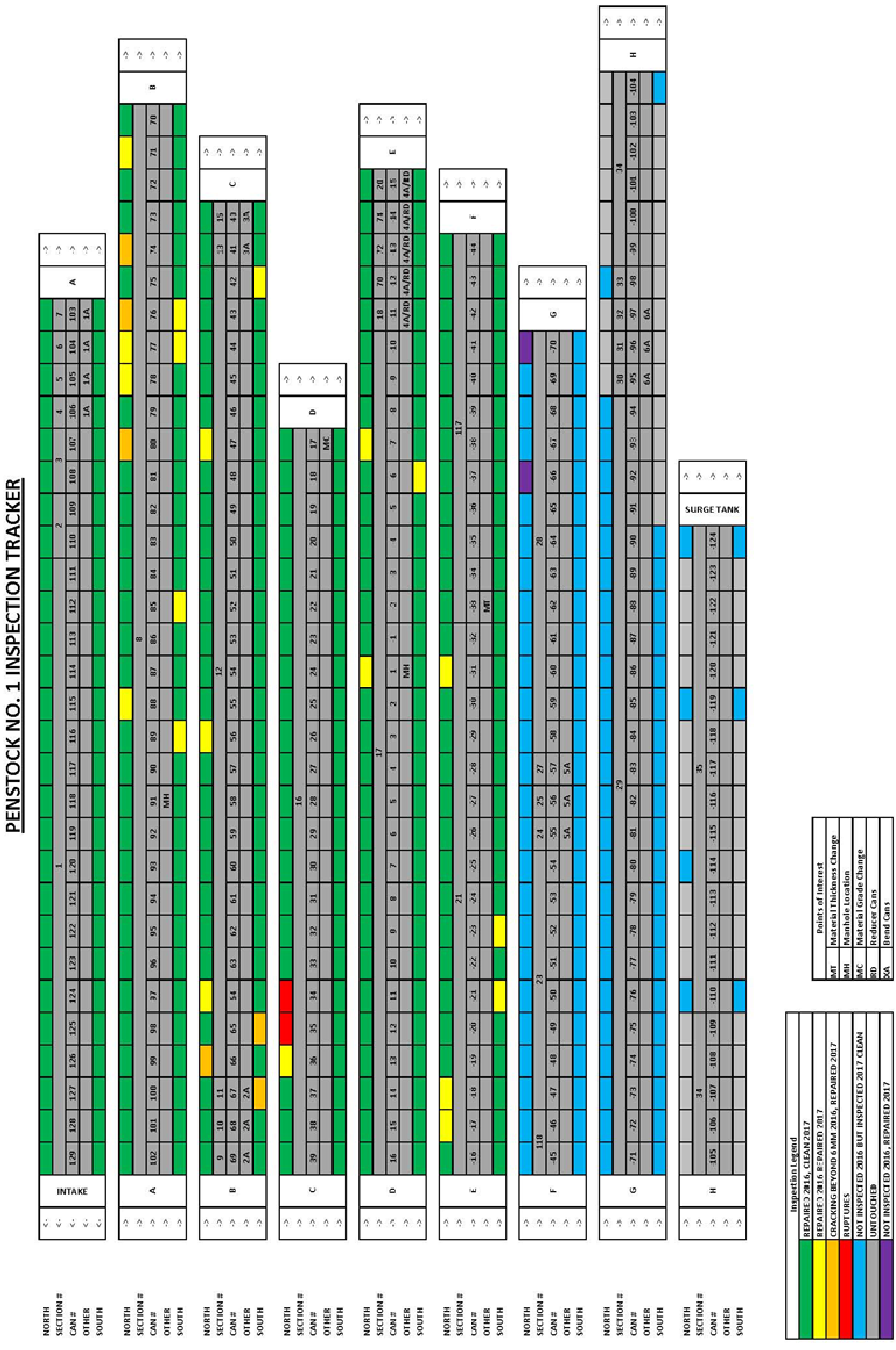
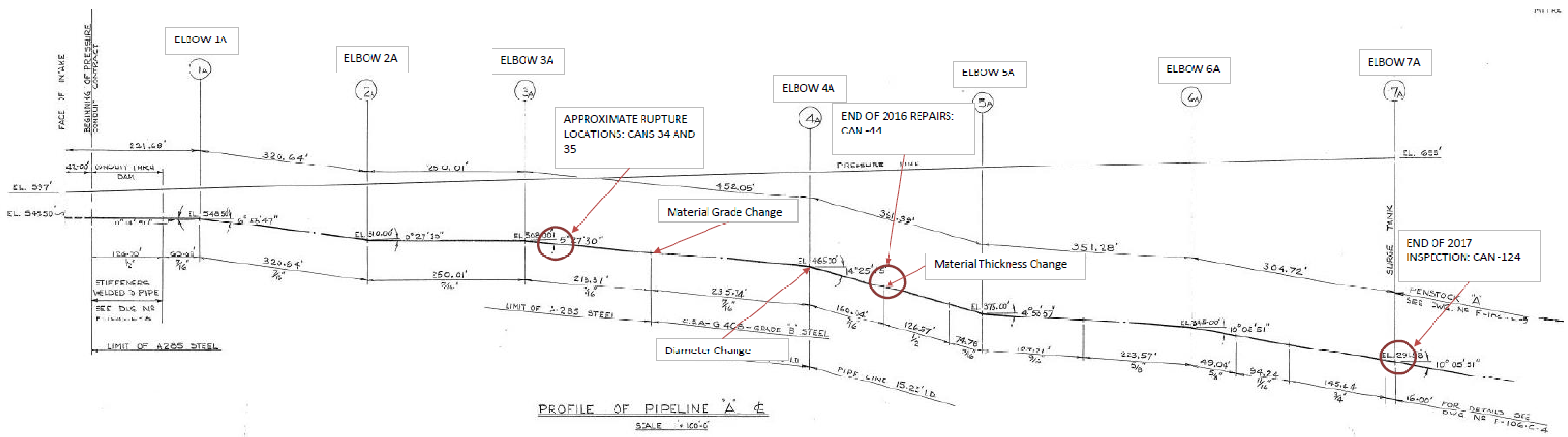


Figure 4-2: Inspection Tracker



Bay d'Espoir Penstock No.1- Profile from Intake (left) to Surge Tank

Figure 4-3: Penstock Profile

5. 2017 Repairs

Hatch designed the repairs of the ruptured penstock can. It involved removal of a 2' wide 9' long longitudinal strip of the penstock can with the crack in the middle (Figure 4-1) and inserting a 1/2" thick pre-rolled (8'6" radius) plate (CSA G40.21 350WT-CAT 4, which is superior to existing) and welding it in place according to the procedure provided by Hatch. For safety, the longitudinal weld in Can 34, repaired originally in May 2016, was also removed and replaced by inserting another 1/2" thick pre-rolled plate. To reinforce the new repaired area and the one from May 2016, spliced reinforcing plates (8'6" radius, 1/2" thick) were welded on the exterior of cans 33, 34, 35 and 36 (see Hatch drawing 352666-D-M-0001.1, rev B).

For the 29 longitudinal seams in other cans with defects or cracks, existing weld metal was removed from inside of the penstock and repair welded. Prior to the installation of the reinforcing plates, the excess weld reinforcement on the longitudinal welds was ground flush. To reduce the stress concentration at the welds and allowed the reinforcing plates to sit tighter to the existing plate surface. In each case a 22" wide 9' long rolled patch plate (8'6" radius, 1/2" thick) was welded in place on the inside of the repaired longitudinal welds, as shown schematically in Figure 5-1 below. Figure 5-1 also shows peaking at the weld.

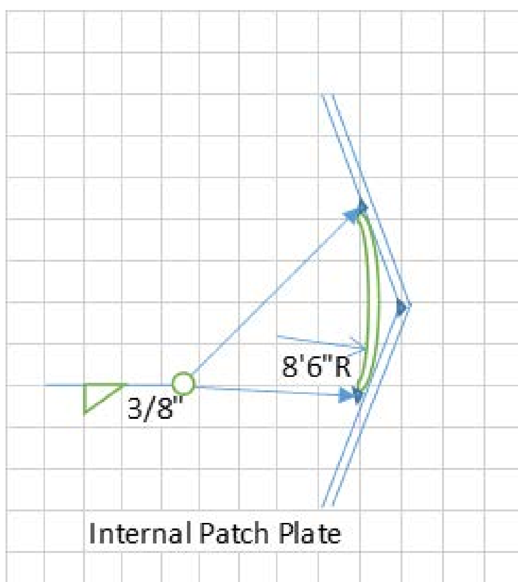


Figure 5-1: Weld Repair of Internal Longitudinal Seams

Table 5-1 shows the statistics of the longitudinal weld inspection and repair.

There were 346 weld seams refurbished in 2016. Comparing the 2017 refurbishment to that of 2016, there is a recurrence of 8.38% and the majority of these defects occurred on the north side of the penstock. All ruptures to date have occurred on the north side.

Table 5-1: Longitudinal Weld Repair Statistics

Item	Description	Number	Units
1	2017 Internal Longitudinal Seams with Defects	31	Count
2	2017 South Internal Seams with Defects	10	Count
3	2017 North Internal Seams with Defects	21	Count
4	2016 Total Seams Repaired	346	Count
5	2016 Total South Seams Repaired	173	Count
6	2016 Total North Seams Repaired	173	Count
7	Approximate Seam Total (Intake to Powerhouse)	870	Count
8	Seams Inspected 2017	430	Count
9	Approximate Total Longitudinal Seam Length	7830	ft
10	Approximate Visual (VT) & Magnetic Particle (MT) Length 2017	3870	ft
11	Approximate Seam Repair Length 2017	279	ft
12	Approximate Seam Repair Length 2016	3114	ft
13	2017 Defects Vs Inspection	7.21	%
14	2017 Inspection Percentage	49.43	%
15	2017 South Internal defects vs total	32.26	%
16	2017 North Internal defects vs total	67.74	%
17	2017 defects on 2016 repairs	8.38	%
18	Approximate 2016 Repairs Vs Total Penstock	39.77	%
19	Approximate 2017 Repairs Vs Total Penstock	3.56	%

6. Testing

To investigate the cause of penstock cracking, Hatch developed a test program to monitor pressure and stresses in the penstock during penstock filling and operation. The penstock was instrumented with strain gauges on the inside and outside adjacent to the penstock failures (T33, T35 and T36) and at a randomly selected location (T65) about 280’ (85m) upstream from the last rupture location. Backfill was partially removed at T65 to expose the external surface of the penstock for applying the strain gauges (see Appendix A for location of strain gauges at T33-T36, T65, and pressure transducers at T33 and T65).

A data acquisition system was installed to record measurements of strains and pressure in the penstock at T33 and T65. Hydro Operations also recorded unit operating parameters and penstock pressure at the powerhouse.

Data was recorded for the following milestones:

- base measurement with strain gauges installed but no backfill at uncovered penstock
- after backfill to original profile per as-built drawing and after additional backfill per Hatch recommendations.
- water at the bottom and top of test locations T33 and T65 (during penstock filling)
- penstock full of water at intake forebay level
- during Unit No. 2 start up and speed-no-load
- during Unit No. 2 rough zone operation
- Unit No. 2- 40 MW load rejection
- Unit No. 1 start up
- Unit No. 1 and No. 2 in rough zone
- Unit No. 1 and No. 2 operating at 70 MW.

Measurement on the inside of the penstock adjacent to the longitudinal weld seam indicates high stresses (280 MPa), above yield (206 MPa) but still below the ultimate tensile strength (380 MPa), with penstock under normal pressure. The increase in local stresses measured adjacent to the longitudinal welds was confirmed by another FE model of the non-circularity (peaking) at the longitudinal welds which is exhibited by all cans. In addition to the high localized stress, cyclic (alternating) stresses of the order of ±15 MPa (2.2 ksi) and ±7 MPa (1 ksi) were measured at the same location during load rejection and rough zone operation, respectively.

A spectral analysis of the measured stresses showed that a few frequencies were predominant in the measurements of internal pressure as well as strains. Further detailed analysis of the data measured shows the penstock is subject to cyclic stresses of lower amplitude and frequency during other events as discussed in Section 8.4.

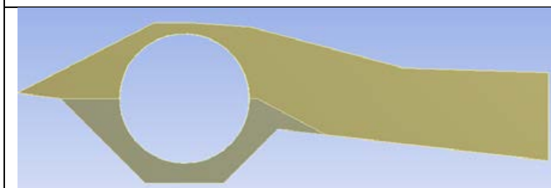
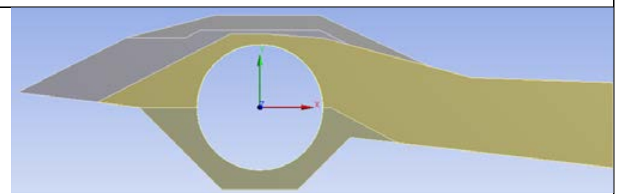
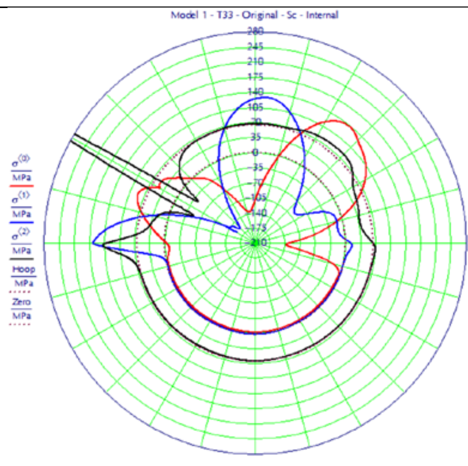
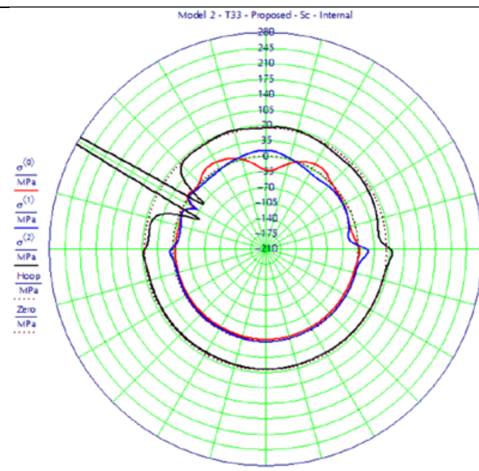
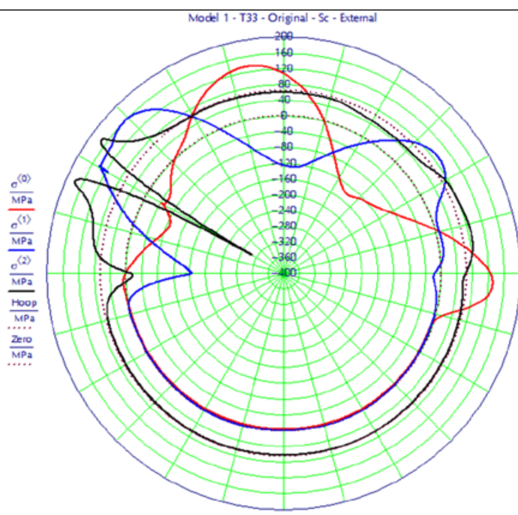
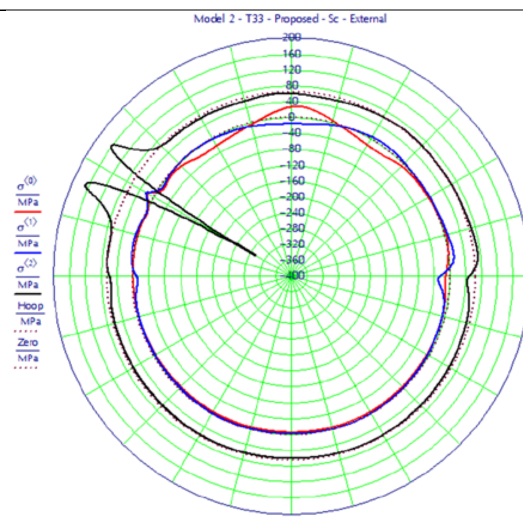
7. Numerical Analysis

A two-dimensional FE model of the steel shell with the abnormal peaking at the longitudinal weld seam and the surrounding backfill was analyzed using the commercially available software ANSYS. The behavior of the backfill was modeled using large deflection non-linear characteristics of the soil.

The results of the FE analysis are shown graphically in Figures 7-1 to 7-4 (see also Appendix C for enlarged view) and the principal conclusions are:

- The geometrical discontinuity due to peaking at the longitudinal weld seam creates very high localized bending stresses.
- The unsymmetrical as-built backfill creates unsymmetrical backfill loads resulting in large deflection of the empty shell and higher stresses during penstock filling (σ_0-red line and σ_1-blue line in Figure 7-1); however, the stresses in penstock under full pressure are not impacted in the same manner by the unsymmetrical backfill (σ_2-black line in Figure 7-1).
- Additional backfill recommended by Hatch creates uniform support of the shell and reduces overall stresses with penstock empty and during filling (σ_0-red line and σ_1-blue line in Figure 7-2 vs Figure 7-1); however, there is only a small reduction in stresses with penstock under full pressure (σ_2-black line Figure 7-2 vs Figure 7-1). Also, increasing the backfill more than that recommended by Hatch (>2') has no incremental benefit in reducing the stresses in the penstock shell when empty, filling or under full pressure.
- Additional backfill beyond the 2 ft cover recommended by Hatch, does not reduce the high local bending stresses in the vicinity of the longitudinal weld seam (30^{o} position in Figure 7-2 vs Figure 7-1) under internal pressure.
- Figure 7-4: shows that when the penstock is empty and filling with no internal pressure (t=1) the maximum bending stress reduces from 250 MPa to 150 MPa if the backfill is symmetrical relative to the as-is unsymmetrical backfill. However, with internal pressure applied, the maximum bending stress at the weld seam reverses to about 650 MPa and the backfill has little or no impact on the amplitude. However, variations in pressure (30 to 45 psi) increases the maximum bending stress from 450 MPa to 650 MPa. It is concluded from this analysis that improving the backfill significantly reduces circumferential bending stress during de-watering/watering up and when the penstock is empty but has insignificant effect on a pressurized penstock. This information was extracted from a theoretical linear elastic model. This allows a comparison of stresses only as the material thickness remains constant and the material does not self-relieve stresses that exceed yield. In reality, material strain hardening takes place progressively in ductile materials once the stresses exceed the yield stress of the material. This would mean the stresses would not be as high as calculated above from strain measurements and the strains

increase progressively as the material is deforming plastically. In essence, at the location of high stress the material permanently stretches slightly which reduces the localized stress.

<table>
<tr><td>FE Model Looking downstream-Backfill-original</td><td>FE Model-Recommended Backfil</td></tr>
<tr><td></td><td></td></tr>
<tr><td colspan="2">Legend: 0=empty penstock (soil + steel weight); 1=filled with water (soil + steel + water weight) 2= pressurized (soil + steel +water weight + 38.21 psi internal pressure</td></tr>
<tr><td></td><td></td></tr>
<tr><td></td><td></td></tr>
<tr><td>Figure 7-1: Circumferential Stresses - As is Backfill - (looking downstream)</td><td>Figure 7-2: Circumferential Stresses - Additional Backfill by Hatch</td></tr>
</table>

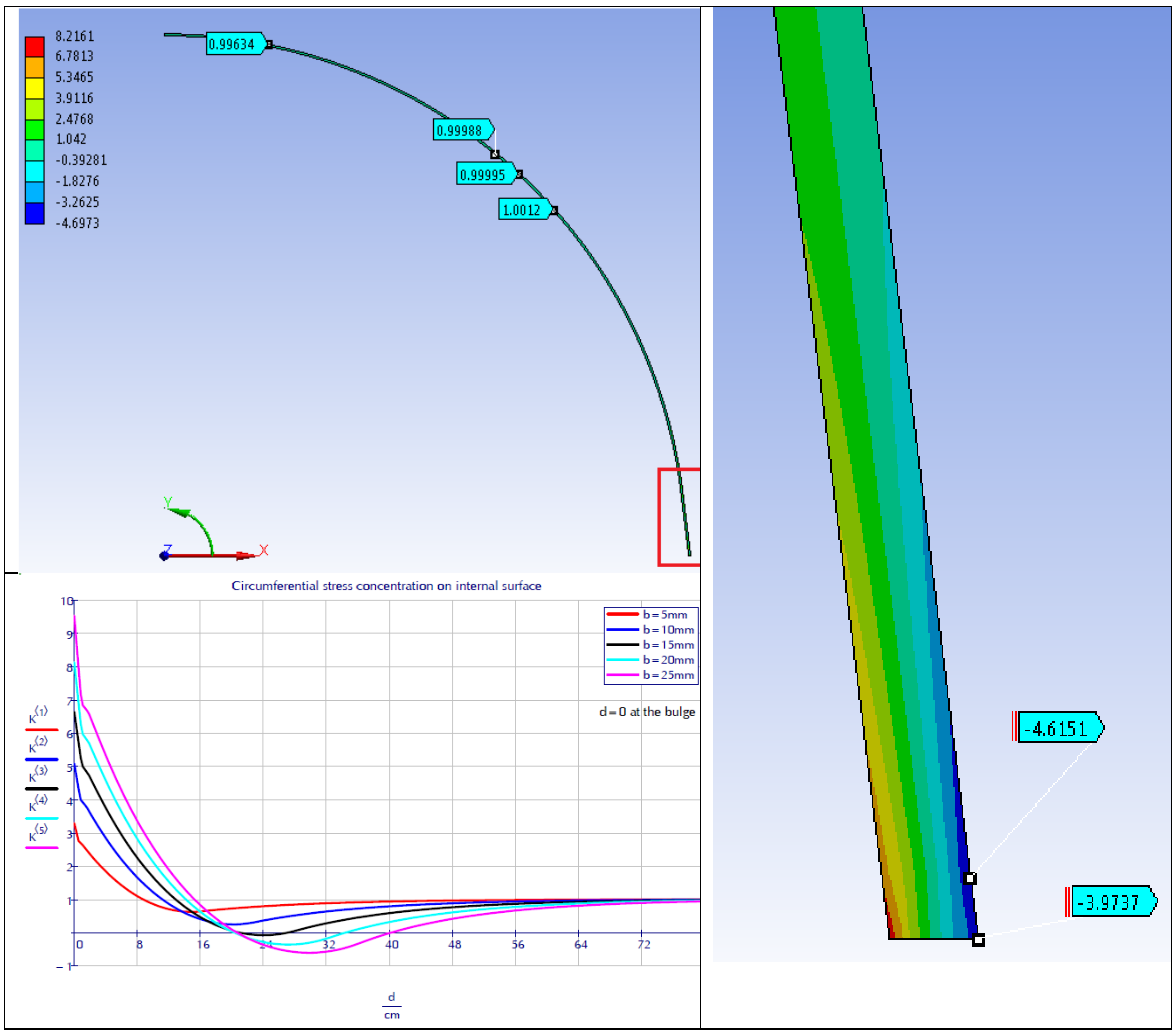
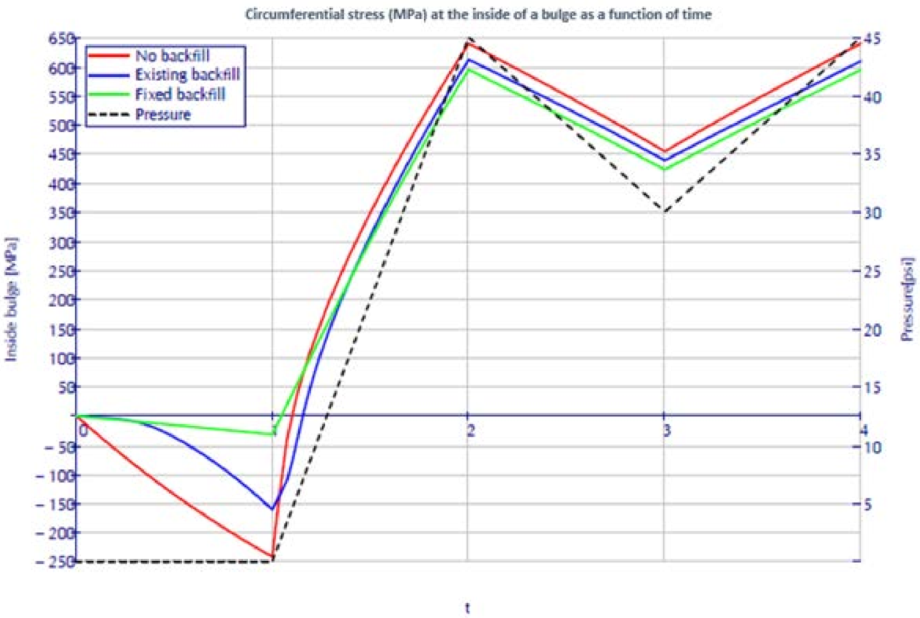


Figure 7-3: Influence of Non-Circular Geometry at Longitudinal Welds Under Pressure



Water weight = hydrostatic pressure gradient with 0psi at the top and 7.4psi at the bottom applied at the internal surface

Pressure = a constant pressure applied at the internal surface

t=1 : Water weight + Backfill weight + 0psi

t=2 : Water weight + Backfill weight +45 psi

t=3 : Water weight + Backfill weight +30 psi

t=4 : Water weight + Backfill weight +45 psi

Figure 7-4: Linear Variation of Maximum Bending Stress at the Weld with Pressure and Change in Backfill

8. Failure Analysis

8.1 Metallurgical Analysis

The penstock shell strip containing the latest rupture was shipped to Atlantic Metallurgical Consulting and Wayland Engineering for metallurgical analysis and material testing. These samples yielded similar material properties to those determined in the 2016 metallurgical analysis completed by Cambridge Materials Testing. The shell material for the penstock was confirmed to be compliant with 1982 chemical requirements for ASTM A 285 Grade C. Additionally, the chemical compositions from both 2016 and 2017 tests noted the presence of higher than normal sulphur content (0.032%) within the shell material by todays standards (0.025%). The AMC report is included in Appendix E.

Initial visual inspection of the fracture surface showed (Figure 4-1) that the crack was approximately 43 inches long and propagated along the toe of the weld for a large portion of the seam and veered into the base metal along one end. During sample removal, the crack continued to propagate parallel to the weld. This would indicate large residual stresses being present within the weld joint. Figure 8-1 maps out different areas of a weld cross section for clarity with regards to the metallurgical summary.

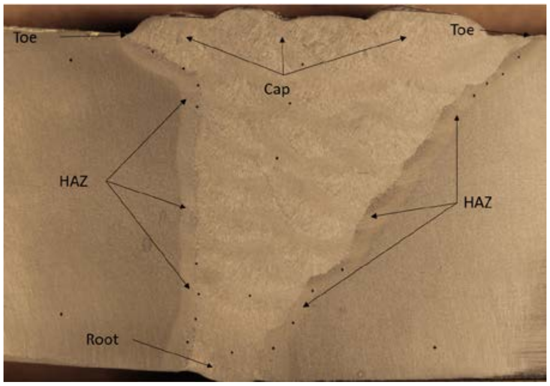


Figure 8-1: Weld Nomenclature

Macroscopic examination of numerous cross-sectional samples showed no evidence of appreciable weld defects or anomalies (porosity, lack of fusion, incomplete penetration). Several macro samples had additional hardness readings completed. The hardness values ranged from 151-164 Hv10 for the base metal, 175-183 Hv10 for the weld metal, and 175-182 Hv10 in the area close to the cracks. The Hv10 hardness test is the Vickers diamond indenter method with 10 kg load on the indenter. Additionally, the microstructures were pearlitic (which is a ductile crystalline structure) in nature and showed no signs of a martensitic (which is a brittle crystalline structure) structure. These results indicate there was no formation of hard phases (that could cause brittleness or accelerated corrosion), that can be caused by rapid cooling after welding.

Two different types of cracks were discovered through macro examination and are shown in Figure 8-2. The primary cracks (through thickness) generally propagate from the toe of the weld through the heat affected zone (HAZ). All observed crack micro examinations had pearlitic structures which is a desirable trait and would indicate that the cracks were not caused by brittle structures. There is evidence of bending and high tensile loading when analyzing the micro photographs. Several of the samples had secondary cracking (interplanar) present. The secondary cracks appear to follow sulphide inclusions that are present within the base material and can likely be attributed to the presence of said inclusions. The sulphide inclusions are most likely caused by the higher than normal sulphur content found in the parent material. Additional testing is being considered to determine if this can be verified. It seems unlikely the secondary cracking is the primary cause of the rupture but could have accelerated the failure.

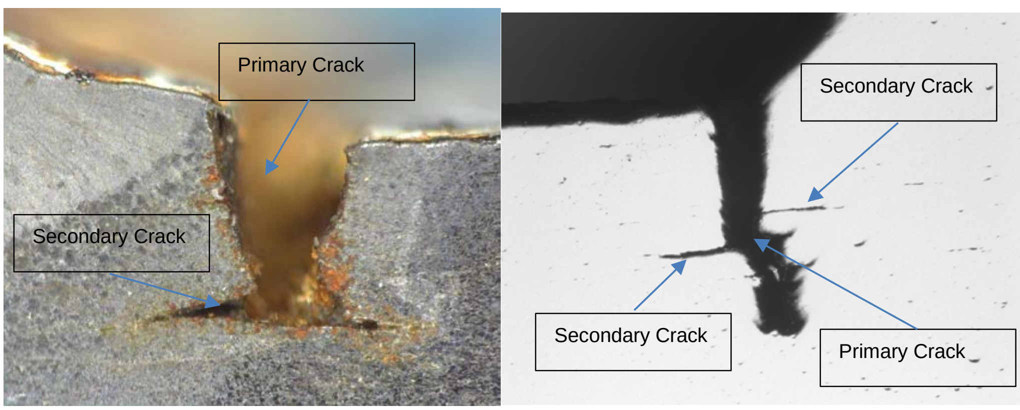


Figure 8-2: Primary Cracks (Vertical) and Secondary Cracks (Horizontal)

Further to the visual, macro, micro and chemical analysis, a set of mechanical testing was completed. The testing consisted of tensile testing for the base metal and the weld metal. The tensile samples failed within the base metal and were also ductile in nature (similar to the results determined in the 2016 investigation). This is further evidence that brittle fracture was not involved and that the material and weld metal is ductile, which is preferred practice for design of steel structures. The tensile test in Figure 8-3 shows an extensive reduction in area and significant cupping which is typical of a ductile failure.

Figure 8-3: Ductile Failure Tensile Tests Penstock No. 1

8.2 Analysis of Test Data

A detailed analysis of the measured data is presented in Appendix A. The following is a summary of key observations. Since the strain gauges were installed with no backfill at the gauge locations but the penstock was already under stress from backfill on adjacent sections, the measurements do not represent accurately the stresses due to the backfill in other sections of the penstock. Similarly, the gauges do not measure residual stress already in the material at the time of gauge installation. The same is not true with the changes in measurements due to internal pressure. It may be observed in Figure 7-1 that the stresses due to backfill (σ_0-red line) are substantially lower than stresses under pressure (σ_2-black line). This would imply that measured stresses may actually be slightly lower than true values. However, this does not affect the measurements of alternating stresses from pressure fluctuations, which appear to be the more likely cause of metal fatigue contributing to penstock rupture.

The principal stresses calculated based on the strain measurements at Can 65 are shown graphically in Figures C-1 to C-2 (Appendix C). The blue line represents stresses on the external surface and the red dotted line represents the stresses on the inside. It may be observed that there is a significant increase in the stresses from Figure C-1 to C-2 due to the static internal pressure of (38 psi). The stresses vary slightly from Figure C-2 to C-3 with unit operating (lower dynamic pressure).

The following are some observations from the recorded measurements:

- As would be expected, the maximum stresses occur when the penstock is under dynamic pressure and subject to a load rejection. The highest measured stress was on the inside in the vicinity of the longitudinal weld seams by gauge T65_INT_P105. Stresses of the order of 280 MPa (41 ksi (283 MPa) > Yield Strength 30 ksi (207 MPa) but < UTS 55 ksi (380MPa)) were measured in the ASTM A285 Gr. C section with the penstock full and during a load rejection. The measured values suggest that the operational stresses were 25% less than the ultimate strength and 37% above the yield strength of ASTM A285

Gr. C. The high stress is attributed to the penstock peaking at the longitudinal weld caused by the lack of rolling radius of the two mating edges.

- A load rejection results in pressure rise of 10% at the powerhouse (259 psi+26 psi). The corresponding pressure waves up the penstock cause fluctuations in pressure at T33 of the order of ±17% (±6.8 psi) in the area where the rupture occurred (Figure 8-4). The corresponding fluctuation in the maximum stress is 280 ± 25 MPa during load rejection (Figure 8-5). Load rejection occurs between 1500 and 3500 seconds and the peak was at approximately 2700 seconds.
- The fluctuations in maximum stress during rough zone operation are of the order of ±7 MPa (1.0) ksi) and ±5 MPa (0.7 ksi) with two units and one unit in the rough zone, respectively (Figures8-5 and 8-6). This is interesting as it was not anticipated that the rough zone operations would result in significant stress fluctuations in the penstock. Rough zone occurs from approximately 4500 seconds onward. Refer to Appendix D for additional detail.

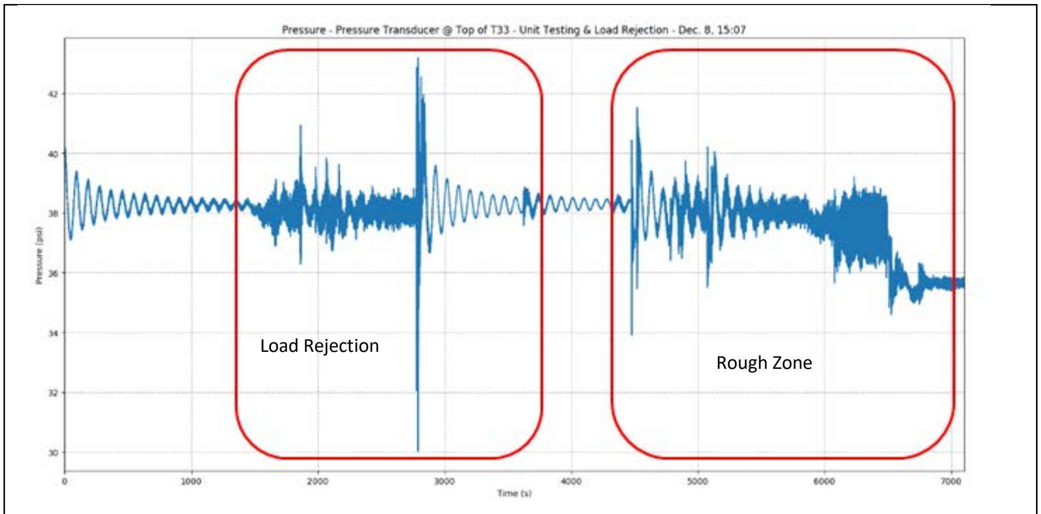


Figure 8-4: Pressure Measurement in Penstock at Can 33 during Rough Zone and Load Rejection

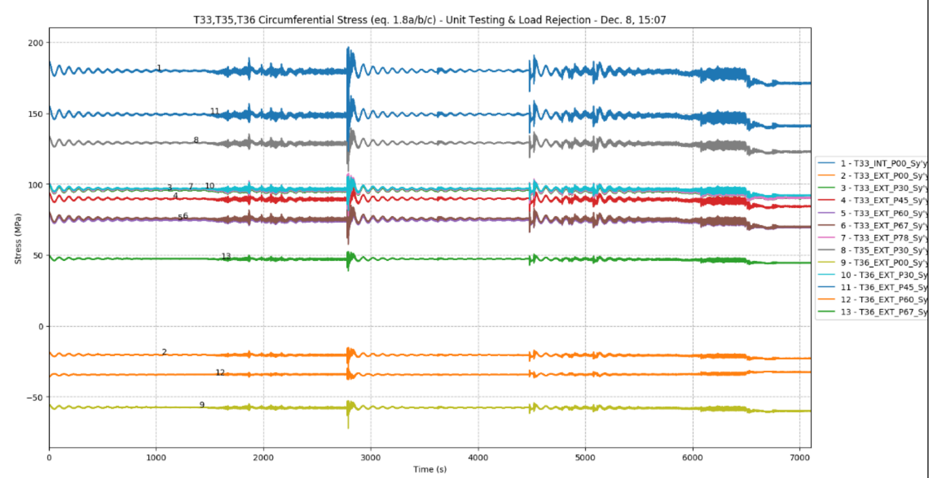


Figure 8-5: Circumferential Stresses in Penstock at Can 33 - Rough Zone & Load Rejection

Figure 8-6: Circumferential Stresses in Penstock at Can 65 - Rough Zone & Load Rejection

8.3 Operational History

Hydro provided the last 5 years of operational data to Hatch to help determine if any operational changes contributed to the failures. The operational data shows high hourly operation in the rough zone for each unit and decreasing start/stop modulation. In general, eliminating unnecessary starts/stops is a common recommendation to increase the life of a system. However, transitioning from stop/start to modulation shows an increased amount of rough zone operation and it appears that the penstock may be spending substantially more time in the rough zone. Based on the measured test results the hydraulic rough zone occurs between 25 to 40 MW. Analyzing the data and approximating the total hydraulic rough zone time shows that recently Penstock No. 1 spends more than 400 hours in the hydraulic rough zone per year. Additionally, 2014 had the highest amount of rough zone operation to date at over 800 hours. The rough zone hours, Figure 8-7, and starts, Figure 8-8, are presented from 2013 to 2017. Additionally, it should be noted that 2016 and 2017 had significant down time for repairs and the duration of rough zone operation would be reduced.

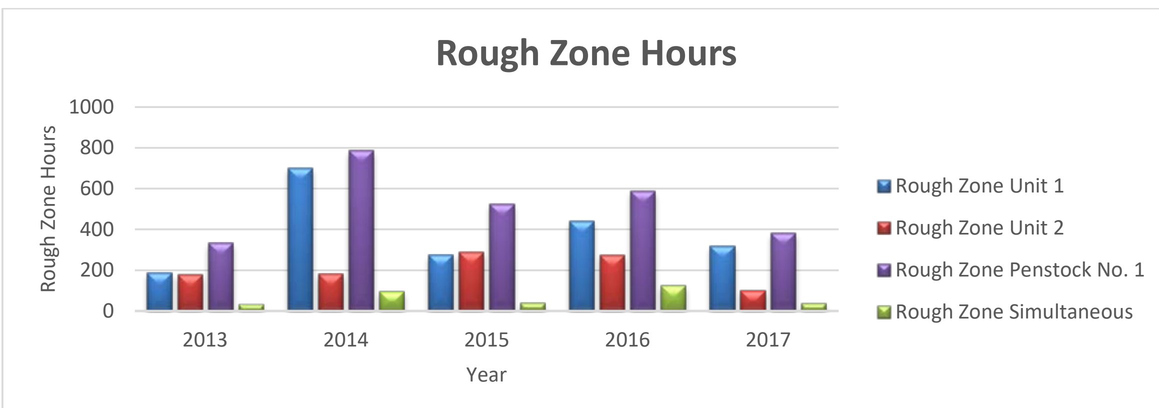


Figure 8-7: Rough Zone Trends

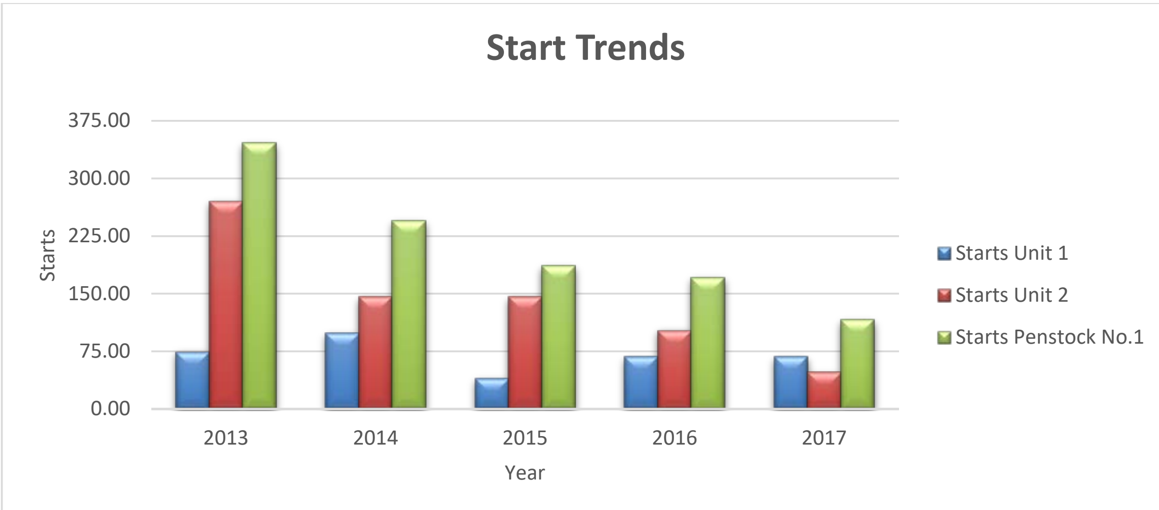


Figure 8-8: Start Trends

8.4 Fatigue Analysis

A comprehensive elastic fatigue analysis was carried out using the measured strains inside the penstock by the gauge closest to the longitudinal weld. The procedure prescribed in Section VIII Division 2 of the ASME Boiler and Pressure Vessel Code (Annex 3F) was used. A detailed account of the analysis is included in Appendix D.

The maximum stress in the weld was calculated by extrapolating the measurements by the strain gauge and a factor (1.42) determined from finite element analysis (Appendix D, 2.1.1). The contribution to fatigue by the various modes of operations and associated cyclic stress and number of cycles is summarized in Table 8-1 below.

Table 8-1: Fatigue Assessment – Total Cycle Damage (No Environmental Factor)

Zone	Fatigue Damage, D
Spherical Valve Opening	0.0025
2 Unit Rough Zone	0.1606
1 Unit Rough Zone	0.4512
Spherical Valve Closing	0.0036
Load Rejection	0.002389
Wicket Gate Opening	0.02583
Wicket Gate Closing	0.04327
Normal Operation	0.24279
Sum	**0.932179**

The above table used a lifetime of cycles (~50 years) for all zones except the rough zones. The only available data for rough zone operation was from 2013-2017, therefore 5 years of rough zone data was used for the assessment.

ASME BPVC VIII.2 notes an environmental modification factor should be applied to the allowable design cycles calculation to account for fluid environment, loading frequency, temperature, and material variables. ASME BPVC VIII does not outline permissible environmental modification factors for this application. Literature research shows that magnitude of the environmental factor as high as 4 has been used in design for extremely corrosive environments with high oxygen content. ASME nuclear codes make reference to the environmental factor and these codes can be considered for general reference but do not directly relate to penstock design. NUREG/CR-6815 ANL-02/39 equates F_{EN} = 1.74 for carbon steels with temperatures less than 150°C. NUREG/CR-6815 also defines a factor of 4 for “moderate or acceptable environmental effects”. As the internal penstock environment is known to be corrosive, the environmental factor >1.07 is considerably more than likely, resulting in a fatigue damage factor greater than 1.00. When the factor reaches a value of 1.00 the design life has been reached.

Additionally, this analysis does not consider the fact that the penstock has undergone stresses exceeding the elastic limit of the material. This would increase the damage factor as well.

The fatigue analysis shows that metal fatigue is a large contributing factor of the most recent failure of Penstock No. 1.

A FE elastic perfectly plastic model was used to determine the plastic strain induced in the penstock at the peaking region from the first pressurization and each consecutive de-water and water up (de-pressurization to re-pressurization). The model used a pressure range of 0 psi (uniform pressure) to 45 psi (maximum pressure during high level head pond and load rejection). The elastic perfectly plastic model works providing no resistance once yield is reached and therefore does not account for strain hardening. This is conservative in nature as strain hardening would increase the yield stress upon each successive cycle until failure. The penstock is able to withstand approximately 15% plastic strain induced before failure. Upon the first pressurization, the penstock has an induced strain of approximately 1.5%. Once plastic strain is induced, each successive cycle only adds a small additional amount of plastic strain until the point of failure. This amounts to ~0.15% plastic strain increase for the existing backfill or ~0.026% increase for repaired backfill, which amounts to approximately 100 cycles for existing backfill or approximately 580 cycles for repaired backfill.

8.5 Probable Cause of Failure

The strain gauge measurements have confirmed the presence of very high stresses (>Yield Strength) in the vicinity of the penstock longitudinal welds on the inside. It is not uncommon for ductile materials to redistribute high localized stress by yielding locally. A failure in such circumstances can result from fatigue due to cyclic loading. The cyclic stresses measured during load rejection and rough zone operation are most likely the cause of fatigue failure.

Based on recent discussions, we understand the September 2016 repair was carried out by forcing the split plates together in order to close the gap to allow it to be welded together. This would have caused very high residual stresses in the parent material and the weld. The combination of the residual stress, the high localized stresses due to internal pressure and newly discovered cycling loading from rough zone operation are likely to have resulted in the November 4, 2017 failure. The failure occurred within 14 months of the original 2016 failure so corrosion would not have played a role in this failure.

Although the magnitude of stress range due to load rejection is higher (2 to 3 times) than that due to rough zone operation, the number of high stress cycles at each load rejection is less than 10, whereas the rough zone operation involves many more cycles (hundreds of thousands to upwards of millions each year).

It is unlikely that a repeat failure such as that occurred at Can 35, only 14 months after the previous repair, can occur within the next 6 months. This conclusion is based on the following:

- The residual stresses introduced by the method of repairing the failure in Sept 2016 are absent in the current repair;
- The reinforcing plate welded over the repair weld seam shares the pressure load and reduces stress in the repair weld by nearly 50%;
- The high localized stress due to peaking at the original longitudinal weld in Cans 34 and 35 does not exist as peaking is not there any more; a new plate was inserted which blends well with the radius of the penstock shell.

- The 29 cans with weld defects were repaired and have a reinforcing plate to reduce the localized stress due to peaking geometry. It is noted that not all longitudinal welds were repaired and a majority of them still exhibit peaking from original fabrication and the accompanying high localized stress. However, with no previous signs of cracking in these longitudinal seams it is not anticipated there will be problems over the next 6 months.
- With the discovery of rough zone impact on the penstock, the number of alternating load cycles while operating in the rough zone is expected to be reduced significantly as operation in the rough zone will be reduced significantly to suit these new findings.

Fatigue analysis indicates that a combination of alternating stresses in the penstock measured during rough zone operation combined with the operation of the spherical valves, wicket gate opening and closing, and operation of the units outside the rough zone have contributed to significant fatigue of the penstock. Amongst these the highest contribution is from rough zone operation (61%), followed by operation outside the rough zone (21%). It should be noted that the latter (normal operation outside the rough zone) is accumulated over the 50-year life-time and is caused by inherent draft tube instability of these units.
Appendix D.2.3.8 shows a measured stress range of about 1.1 MPa at a frequency of 0.4 Hz during normal operation.

9. Risk Assessment

This section examines the risk of penstock failure during the 2018 year.

	Description of Risk	Mitigation	Risk Ranking	Consequences	Actions
1	Cracks develop at the location of previous repairs	Peaking geometry causing high local stresses has been removed. An overlapping patch plate has been welded to cover the longitudinal welds and thus share the load due to internal pressure. All welds have been inspected by magnetic particle examination (MT).	Low	Failure resulting in Units No.1 & No. 2 being unavailable for power generation	None
2	Cracks develop at other longitudinal welds in the upper section of the penstock.	All welds were MT inspected. Defects were removed and repaired by welding followed by MT. A 22' wide patch plate was welded on top of each repaired longitudinal weld on the inside to reduce high local bending stresses caused by peaking geometry.	Low	Failure resulting in Units 1 & 2 being unavailable for generation	Inspect Penstock No. 1 during the 2018 summer and determine future inspection frequency.
3	Accelerated growth of cracks in longitudinal welds due to cyclic Loading	It is recommended that Units No. 1 & No. 2 are operated in the rough zone no longer than necessary during load ramp up and shut-downs.	Low	Failure resulting in Units No. 1 & No. 2 being unavailable for generation	Do not operate in the rough zone.
4	Other sources of transient pressure due to unknown events such as malfunction of spherical valve operation	Investigate spherical valve operation; measure pressure at the valve and in the penstock during valve closing, closed and opening. Remove any potential of hunting in the seal controls which may cause pressure transients.	Low	Failure resulting in Units No. 1 & No. 2 being unavailable for generation	None – investigation complete.
5	Inadequate bedding support for the penstock	Backfill has been added on top and the backfill profile on the penstock has been upgraded to reduce risk of sloughing or unsymmetrical loading on the penstock.	Very Low	High stresses in the penstock due to longitudinal bending	None
6	Penstock Failure resulting in loss of bedding due to erosion by release of water	Based on the lower pressures and history of previous ruptures, this section of the penstock exhibits "Leak before catastrophic failure" characteristics. Therefore, monitoring can reduce consequences of failure. It is recommended that the penstock be inspected visually every day for water leakage. Cameras should be used to give the plant operator a view of the upper reaches of the penstock. Installation of an infra-red camera should be explored.	Low	High stresses in the penstock due to longitudinal bending could result in a massive failure	Daily inspection; install camera for monitoring; investigate leak source.

	Description of Risk	Mitigation	Risk Ranking	Consequences	Actions
7	Damage caused by Load Rejection	The penstock was commissioned and tested for one-unit load rejection. Theoretically, a simultaneous two-unit load rejection could double the range of pressure cycles and hence the localized stresses near the longitudinal welds. It is recommended that a visual inspection of the penstock be carried out after each load rejection (one or both units).	Very Low	Premature penstock failure causing unavailability of the units	Visually inspect penstock after each load rejection.

10. Long-Term Solutions for Penstock No. 1

The repair of Penstock No. 1 in November 2017 was carried out with the primary purpose of reinstating it into service at the earliest possible date while ensuring penstock rupture would not occur during the winter months. The investigation into the cause of recent failures, discussed in this report, leads to the conclusion that there is a structural problem with Penstock No.1 which is the deviation from the circular geometry at the longitudinal welds. ASME BPVC VIII.1 states the permissible out-of-roundness of cylindrical shells shall not have a cross sectional difference exceeding 1% between the maximum and minimum diameter (1% of 17’ diameter equals ~50.8 mm; measurements of peaking is upwards of 30 mm or 60 mm on the diameter), therefore the penstock is not within the permissible limits. This combined with the pressure fluctuations resulting from turbine operation, the corrosiveness of the water and the age have all contributed to the recent ruptures. While the penstock may last several more years before the next failure, long-term solutions should be examined.

Table 10-1 is a preliminary list of possible long-term solutions with advantages and disadvantages of each.

The scope of this study and time constraints do not permit an analysis or discussion of these alternatives at this time. The identification of a long-term solution requires further study.

Table 10-1: Long Term Solution Matrix

Item Number	Description	Advantages	Disadvantages
1	Run parallel penstock for sections or entire length	1. Low risk of failure 2. New penstock can be constructed to meet current standards 3. Existing penstock can remain in operation until final tie ins	1. High cost 2. Large amount of civil work required 3. Encroaching on Penstock No. 2 backfill and cover is likely 4. Heavy machinery, lifting activities, and excavation around two operational penstocks. 5. High likelihood of weather delays 6. High likelihood of requiring rock blasting.
2	Replace sections of penstock in phases in-situ	1. Low risk of failure 2. New penstock can be constructed to meet current standards 3. Construction can be phased 4. Not disturbing Penstock No. 2	1. High cost 2. Multiple outages required 3. Cost of removal of existing penstock will be incurred 4. High likelihood of weather delays
3	Install internal weld seam reinforcing similar to temporary repairs	1. Lower risk of failure 2. Construction can be phased 3. Work is all internal and weather delays would be minimal 4. Not disturbing Penstock No. 2	1. High cost 2. Multiple outages required 3. Work is confined space 4. Extensive scaffolding requirement 5. Possible flow disturbances caused by plates protruding into flow contributing to head loss 6. Long-term effectiveness not predictable
4	Install external weld seam reinforcing similar to temporary repairs	1. Low risk of failure 2. Construction can be phased	1. High cost 2. Requires removal and reinstatement of backfill for exterior shell access. 3. High likelihood of weather delays 4. Long-term effectiveness not predictable
5	Form around penstock and encase in concrete	1. Low risk of failure 2. Construction can be phased 3. No outages required 4. Not disturbing Penstock No. 2	1. High cost 2. High likelihood of weather delays 3. Corrosion due to moisture between steel and encasement could lead to premature failure
6	Install external stiffener rings	1. Low risk of failure 2. Construction can be phased	1. High cost 2. Requires removal and reinstatement of backfill for exterior shell access. 3. Extensive excavation and shoring requirements to install full 360 degree stiffeners. 4. High likelihood of weather delays. 5. Due to extensive excavation requirements there is a possibility of encroaching on Penstock No. 2. 6. Existing material is prone to sloughing which presents a large safety risk to personnel working inside extensive trenches. 7. Requires multiple outages 8. Does not eliminate the stress intensification at the bulge except in the vicinity of the stiffener rings
7	Install internal stiffener rings	1. Low risk of failure 2. Construction can be phased 3. Work is all internal and weather delays would be minimal 4. Not disturbing Penstock No. 2	1. High cost 2. Multiple outages required 3. Work is confined space 4. Extensive scaffolding requirements 5. Increased head loss due to flow disturbances caused by rings protruding into flow. 6. Does not eliminate the stress intensification at the bulge except in the vicinity of the stiffener rings 7. Potential output reduction

Item Number	Description	Advantages	Disadvantages
8	Install new steel liner inside existing penstock	1. Low risk of failure 2. Construction can be phased 3. Work is all internal and weather delays would be minimal 4. Not disturbing Penstock No. 2	1. High cost 2. Multiple outages required 3. Work is confined space 4. Extensive scaffolding requirements. 5. Risk of corrosion due to moisture trapped between the two shells. 6. No access for full penetration welds of circumferential joints. 7. Higher head loss due to reduced cross-section
9	Install Fiberglass liner	1. Low risk of failure 2. Construction can be phased 3. Work is all internal and weather delays would be minimal 4. Not disturbing Penstock No. 2	1. High cost 2. Multiple outages required 3. Work is confined space 4. Extensive scaffolding requirements
10	Install concrete liner	1. Low risk of failure 2. Construction can be phased 3. Work is all internal and weather delays would be minimal 4. Not disturbing Penstock No. 2	1. High cost 2. Multiple outages required 3. Work is confined space 4. Extensive scaffolding requirements 5. Possibility of concrete becoming dislodging during operation and migrating into the turbine 6. Higher head loss due to reduced X-section.
11	Cut top off of existing penstock and install new penstock inside	1. Low risk of failure 2. New penstock can be constructed to meet current standards 3. Construction can be phased 4. Not disturbing Penstock No. 2 5. Reduced excavation costs	1. High cost 2. Multiple outages required 3. Cost of removal of existing penstock material will be incurred 4. High likelihood of weather delays 5. The material of the lower half of the old penstock has corroded and has been subjected to cyclic loading which could shorten its life.
12	Increase inspection frequency (once per year) and keep existing penstock in service	1. Medium risk of failure 2. No capital cost incurred 3. Existing penstock can remain in operation	1. Increased operational cost 2. Possibility of failures occurring in heating season 3. Units not available for production during inspection outages.
13	Cut out a section of the shell plate around each longitudinal seam and weld in place a rolled plate section, similar to the manner in which the 2017 repair was carried out but without any external reinforcing plates	1. Lower risk of failure 2. The stress concentration at the longitudinal weld due to non-circular geometry is reduced significantly. 3. Construction can be phased 4. Not disturbing Penstock No. 2	1. Labor intensive with higher cost 2. Multiple outages required 3. Cost of removal of existing penstock material and backfill will be incurred 4. High likelihood of weather delays 5. Longevity of the solution is not predictable.
14	Combination of Alternatives (12) and (13): Inspect the penstock annually and if defects continue to show up, remove section of plate with the longitudinal weld and weld in place a new inserted rolled plate	1. Medium risk of failure 2. Moderate capital cost incurred to allow deferment of high capital requirement for total replacement 3. Existing penstock can remain in operation	1. Increased operational cost 2. Reduced possibility of failures occurring in heating season 3. Units not available for production during inspection outages.
15	Installation of Unit number 8 on Penstock No.4 and utilizing Penstock No.1 as back up and repair on an as needed basis	1. Lower risk of failure 2. Operational time of failure prone penstock is greatly reduced. 3. Construction can be phased 4. Not disturbing Penstock No. 2 5. Allows reserve capacity for more maintenance flexibility which is required for aging assets.	1. High cost 2. Large amount of civil work required 3. Heavy machinery, lifting activities, and excavation around one operational penstock. 4. High likelihood of weather delays 5. Higher head loss = less output

11. Penstock No. 2 and No. 3

Penstock No. 2 was built to the same design and specifications as Penstock No. 1 and was constructed a year later. External rings were discovered during inspection in 2016. However, there are no drawings showing these rings. Under similar operating conditions and depending on their design, a penstock with external rings would be expected to last longer. NDT of internal longitudinal welds in 2016 showed significantly lower defects as compared to Penstock No.1.

Penstock No. 3 which is a similar design was built a couple of years later than Penstock No.2. However, the drawings show a symmetrical and improved backfill design. These drawings, and those for the other two penstocks, do not show any external reinforcing rings.

Considering the similarity in the design and operating conditions of the three penstocks and the recent ruptures in Penstock No. 1, it is prudent to have a comprehensive inspection and assessment program for Penstocks No. 2 and 3. This should include measurement of any deviations from circularity of the penstock profiles at the longitudinal welds. This can be performed by laser survey similar to Penstock No. 1 as completed in 2017. Backfill should be removed at a few locations to ascertain the size and spacing of any external stiffener rings. NDT of the longitudinal seams and shell thickness measurements should be carried out inside the penstock. Since all 6 of the BDE units are known to suffer from instability due to draft tube surges, instrumentation should be installed to determine the pressure variations in the penstock during start, stops and regular operation.

12. Conclusions

Visual inspection of the November 4, 2017 failure and metallurgical examination of the material indicates that the failure originated at the toe of the previous repair weld and progressed through the parent material. Metallurgical testing completed by Atlantic Metallurgical Consulting and Wayland Engineering concluded the material in the penstock met the criteria for the specifications on the design drawings and there were no brittle microstructures induced by the welding process. No metallurgical contribution can be attributed to the rupture. This failure was most likely caused by a combination of the following factors:

- High residual stress due to re-welding of the failed seam under high load used to bring the two edges of the ruptured joint together.
- Highly localized bending stresses due to the geometry (peaking) at the longitudinal weld seam under internal pressure (measured and verified by FE modeling).
- Fatigue caused by high cycle low amplitude stresses due to extended operation in the rough zone over the last year.
- Fatigue caused by high cycle low amplitude stresses due to pressure fluctuations originating from inherent draft tube instability during normal operation over the 50-year life-time.

Hatch believes that the risk of failure of Penstock No. 1 from now until the next inspection, which will take place in the summer of 2018, is relatively low. Based on the observation in November 2017 that showed defects appear in 8% of the longitudinal welds repaired the previous year, it is possible that similar cracks may begin to form but is unlikely they will progress to a critical depth to cause a rupture within this timeframe. However, it should be noted that very high stresses were measured in the vicinity of the longitudinal welds under normal pressure and that the penstock has accumulated damage over its life time in other areas not detectable by the inspections carried out.

Backfill has only a marginal improvement of stresses for a pressurized penstock but significantly reduces the circumferential bending stresses when de-watering, empty, and watering up the penstock.

13. Recommendations

The following recommendations, have been already implemented.

- Repair the section of the failed penstock (Can 34) by removing the entire canned segment with the crack, insert a new ½" thick plate and weld in place followed by MT. Install a reinforcing overlap plate over the previously repaired longitudinal welds (Cans 34 & 35).
- MT all longitudinal welds between the intake and the surge tank on the inside. Remove defects, repair weld & MT. Install a 22" wide patch plate over the repaired weld on the inside to reduce the localized bending stress due to the peaking at the weld.
- Add backfill to make it symmetrical and prevent sloughing over part of the penstock.
- Install strain gauges and pressure transducers in the vicinity of the affected areas of the penstock and monitor during commissioning and periodically thereafter (unusual events such as load rejections until February 2018.
- Investigate the operation of the spherical valves and any adverse impact it may have in causing pressure transients with potential to cause damage to the penstock.
- Examine alternatives for long-term mitigation.

It is recommended that Penstock No.1 which serves Unit No. 1 & No. 2 operation may be continued with the following considerations:

- Operation of the units in the rough zones should be limited to that necessary to ramp up and down through the rough zone.
- Walk the penstock once a day and after unusual pressure transients, such as load rejections, for evidence of leaks and regularly observe the area by camera.
- Verify integrity of existing strain gauge signals by testing continuity. Purchase a data acquisition system capable of receiving data from the existing instrumentation. Continue to monitor the remaining strain gauges and pressure transducer periodically.
- Inspect Penstock No. 1 during the summer of 2018 and determine inspection frequency based on findings. Inspection procedure should be as follows:
  - Inspect interior re-pad welds using visual and magnetic particle. Welds need to be cleaned, visually inspected and then inspected by magnetic particle. Suggest high pressure water washing prior to inspection.
  - Inspect 5 additional cans upstream and downstream of the ruptured area (Cans 34-36). Once complete, inspect every 5th can upstream of the rupture area to the intake and similarly downstream to the surge tank. Inspect visually and with magnetic particle.

- Inspect the penstock downstream of the surge tank for out of roundness at the longitudinal welds for 'peaking' which is present in the upper reaches of the penstock.

Penstock No. 2 should be inspected at the next available outage as follows:

- Inspect all previously repaired welds with visual and with magnetic particle. Prior to inspection, welds need to be cleaned.
- Inspect 5 cans upstream and downstream of this area followed by every 5th can upstream of the repair area to the intake and similarly downstream to the surge tank with visual and with magnetic particle.
- Complete internal laser survey to check ovality and peaking.
- Install a pressure transducer to determine if pressure variations similar to Penstock No. 1 exist.

Penstock No. 3 should be inspected at the next available outage as follows:

- Starting from the manhole, close to Can 0. Inspect 10 cans upstream and downstream by visual and with magnetic particle. Prior to inspection, welds need to be cleaned with de-scalers and flapper style grinding disks.
- From the last inspected can, inspect every 10th can upstream and downstream until intake to the surge tank has been fully inspected. Based on this inspection, we can establish the extent of the required refurbishment, if required.
- Complete shell thickness measurements.
- Complete laser survey to check ovality and peaking.
- Depending on findings, we may recommend mechanical testing to determine mechanical and chemical properties of penstock material.
- Install a pressure transducer to determine if pressure variations similar to Penstock No. 1 exist.

Penstock No. 1 planned remedial work:

- Backfill and re-coating operations should be postponed. Based on findings from planned inspections, if no further deterioration of the welds is discovered, replacement of the penstock would likely be unnecessary. Backfill and re-coating would then be required for long term operation. If further deterioration is encountered, the long-term solutions should be revisited.

Appendix A
Data Collection and Analysis

A.1 Introduction

The following is a presentation of the tests and analysis of data carried out on Penstock No. 1 at the Bay d'Espoir Hydroelectric Generating Facility (BDE) after its repair in November 2017. Hatch was involved in the repair procedure and as part of the root cause analysis, recommended installation of strain gauge rosettes and pressure transducers in the affected area of the penstock. Data was collected before, during and after filling of the penstock, and during operation at various loads followed by a 40% load rejection.

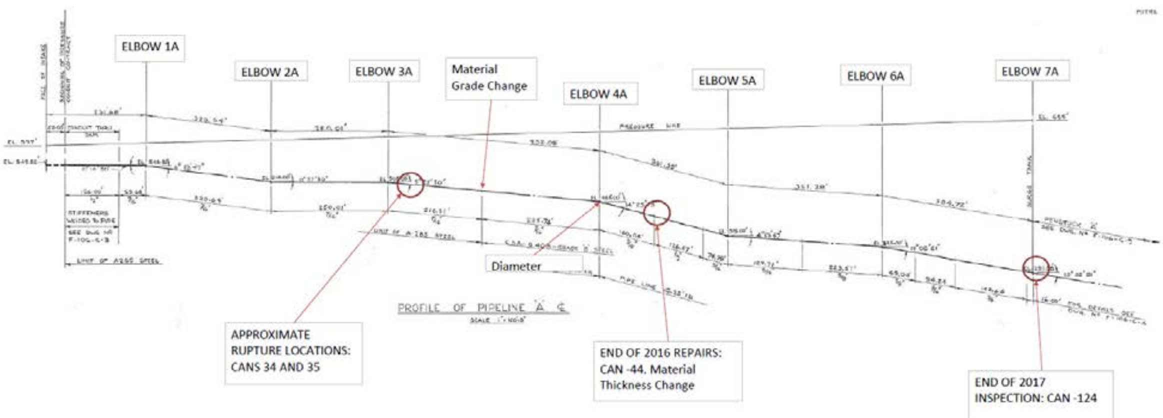


Figure A-1: Penstock Profile – Intake to Surge Tank

Figure A-1 shows the location of the failures in upper section of the penstock. Figures A-2, A-3 and A-4 show the location of the strain gauges and the pressure transducers around the penstock. Strain gauge rosettes (350Ω 6mm gauge length) of the 0/45/90 pattern were installed from Nov. 29, 2017 to Dec. 6, 2017. The strain gauge and data acquisition equipment installation was completed by personnel from the National Research Council (NRC) as a subcontractor to Cahill.

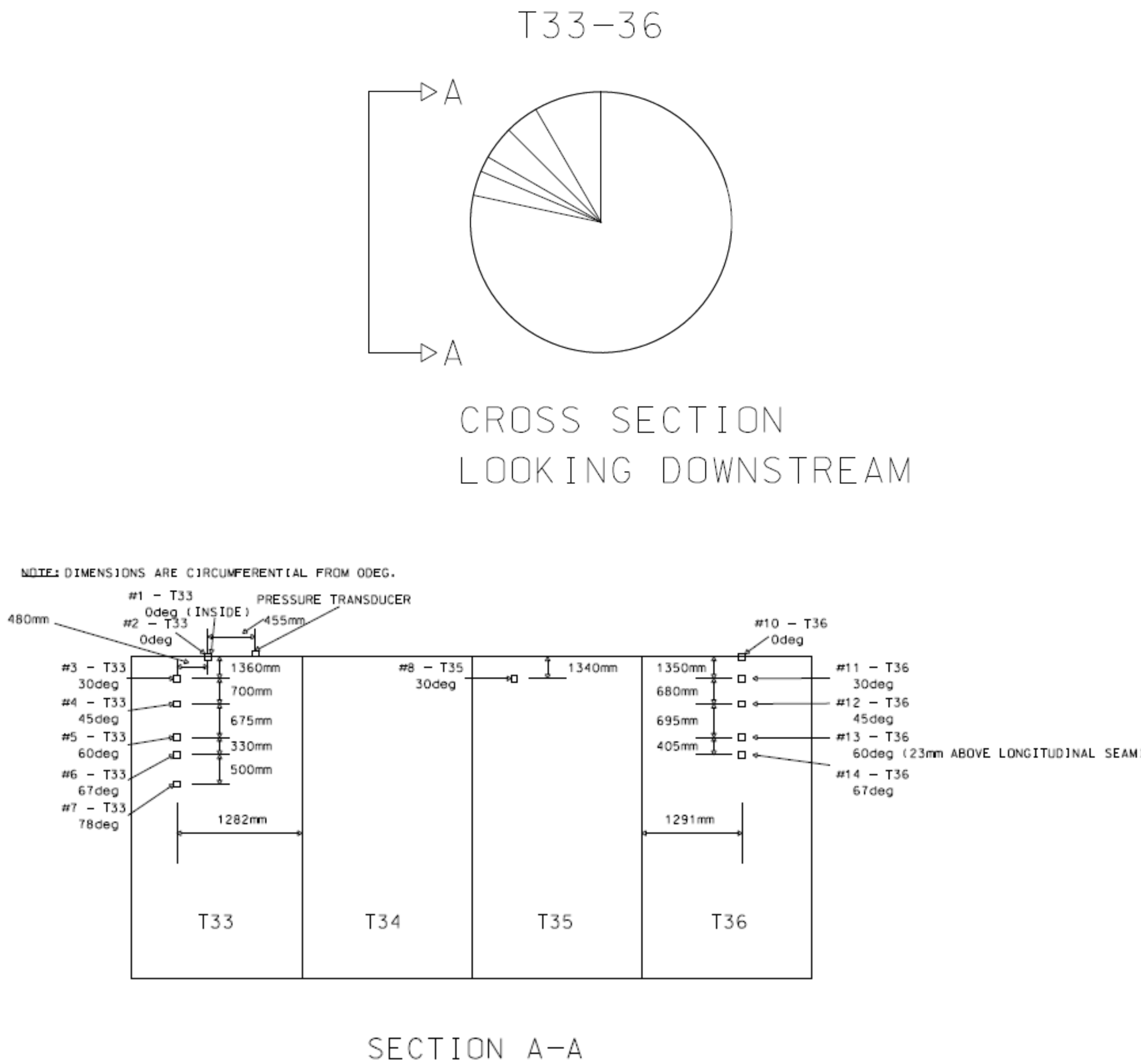


Figure A-2: T33-T36 Strain Gauge Layout

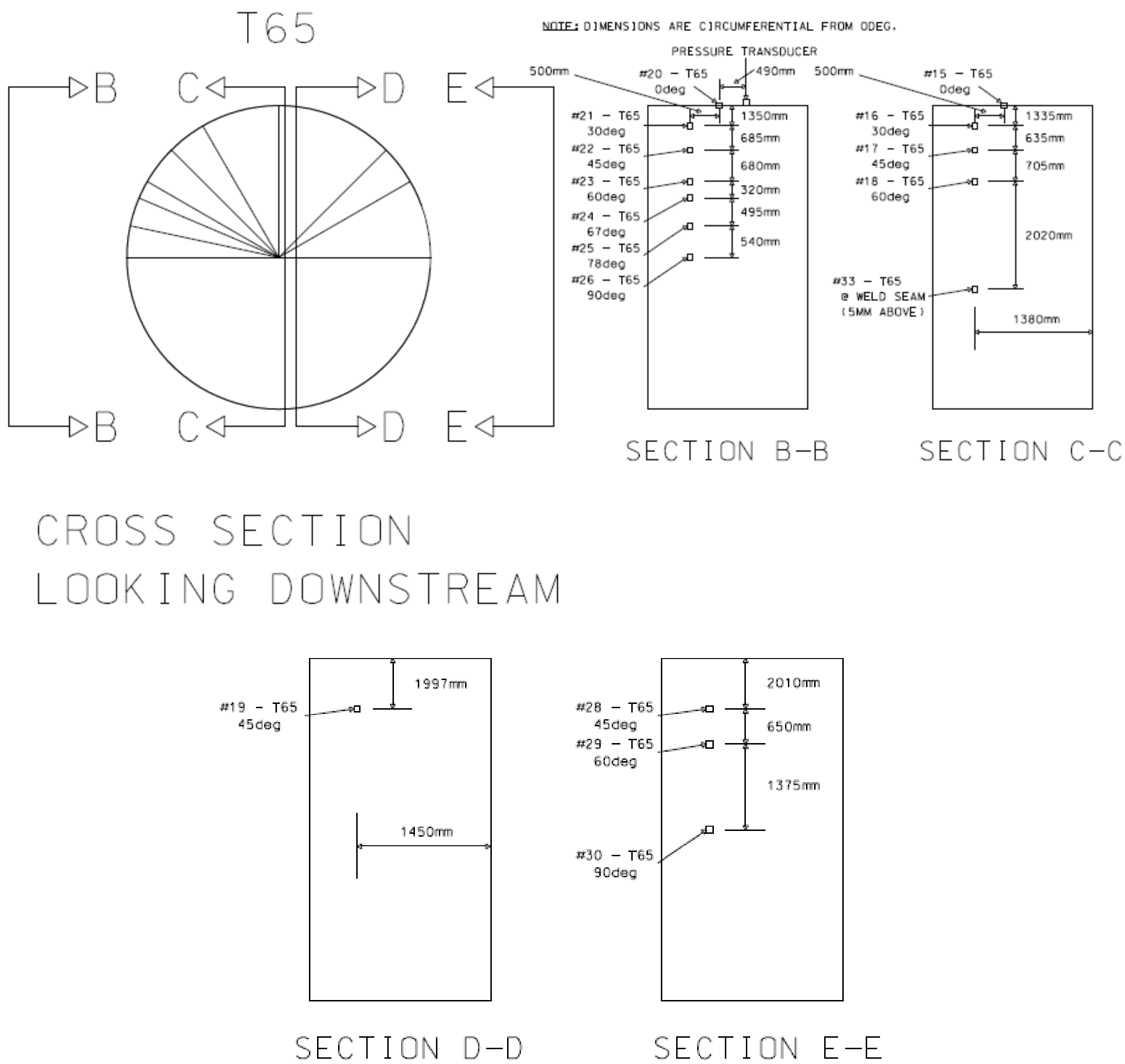
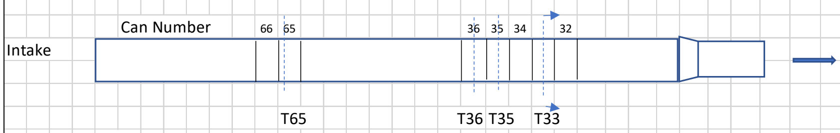
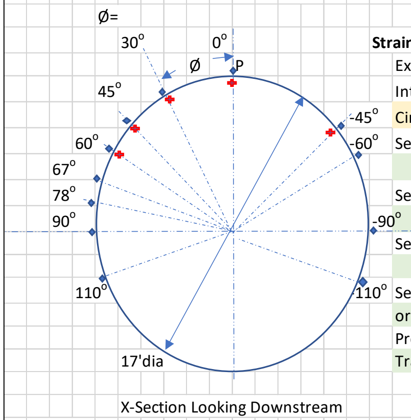


Figure A-3: T65 Strain Gauge Layout

Nalcor- Bay d'Espoir Penstock No. 1 Hatch 2017.11.25

Monitoring Instrumentation - Post-repair Nov 4, 2017 Failure





Strain Gauge Rosette Locations rev D (minimized inside strain gauges)

Exterior: ◆
Interior: ✚

Circ.Location Ø		0°	30°	45°	60°	67°	78°	90°	110°	-45°	-60°	-90°	-110°	
Section	T33	◆	◆	◆	◆	◆	◆							Exterior
		✚												Interior
Section	T35		◆		◆									Exterior
														Interior
Section	T36	◆	◆	◆	◆	◆								Exterior
														Interior
Section	T65	◆	◆	◆	◆	◆	◆	◆	◆	◆	◆	◆	◆	Exterior
or Alternate		✚	✚	✚	✚					✚				Interior
Pressure	T33	P												Exterior
Transducer	T65	P												Exterior

Notes:

1. Use 0-45-90° 3-Strain Gauge Rosettes installed on cleaned and smooth surfaces; align inside and outside gauges to be opposite each other.
2. Protect gauges with epoxy coating and record location of gauges with tape measurement from the top of penstock (12 O'clock).
3. Drill holes on top of Cans 33 and 65, suitable for pressure transducers and pulling the wiring from the internal gauges, and install coupling with water tight bushing (against max pressure of 75 psi)
4. Install pressure transducer on top of Can 33 and Can 65(range 0-100 psi)
5. Monitor strain gauges and pressure transducer as per test sequence below
6. Use software for on-line strain/stress calculations during commissioning and Data Logger for long-term data storage.

	Test Sequence (measurements of strains, pressure and synchronizing Clock)	Estimated Duration, days	(cum)
1	Install equipment and Zero all gauges with penstock empty; no backfill at repair area Cans 33-36 and at Can 65	5.0	5.0
2	Measurements during and after backfill placement at Cans 33-36 and Can 65	0.5	5.5
3	Measurements after additional backfill placement over 130 m of penstock (Can 34 ±65m)	2.0	7.5
4	Measurements during Penstock fill up (after the water has reached the bottom of Can 34 (monitor pressure at Powehous displayed at Intake)	0.5	8.0
5	Measurements during U2 start up and at speed-no-load	0.5	8.5
6	Measurements during U2 ramp up to and in rough zone (25 MW)	0.5	9.0
7	Measurements U2 at 50 MW	0.1	9.1
8	Measurements during 50 MW load rejection	0.1	9.2
9	Start U1 and take measurements with U1 on Load	0.2	9.4
10	Start U2 and take measurements with both U1 and U2 on Load	0.2	**9.6**
11	Periodic Monitoring for four weeks once per day for 1 hour (preferably with both or either unit on load	28	
12	Evaluate 4 week data and decide on future need for recording data		

Figure A-4: Location of Pressure Transducers and Strain Gauges

A.2 Strain Gauge Installation and Data Acquisition

The strain gauge installation for cans T33, T35 and T36 was complete on Dec. 3, 2017, followed by a 10-minute baseline data collection on Dec. 4, 2017 (11:12am). Backfilling of the area started immediately after the baseline was taken. At 8:20am the backfill was to the approximate existing level (till only) and 10 minutes of data collection was taken.

The strain gauge installation for can T65 was complete on Dec. 6, 2017 followed by a 10-minute baseline data collection. Backfilling of the area started immediately after the baseline and was completed at approximately 19:45 that night.

Water up of the penstock began at 12:00am on Dec. 7, 2017:

1. The first hold point (T33 Bottom – 212 PSI at the powerhouse spherical valve) was reached at 11:29am.
2. The second hold point (T65 Bottom - 216 PSI at the powerhouse spherical valve) was reached at 12:07.
3. The third hold point (T33 Top - 220 PSI at the powerhouse spherical valve) was reached at 13:11.
4. The fourth hold point (T65 Top - 223 PSI at the powerhouse spherical valve) was reached at 14:17.
5. The filling of the penstock was complete at approximately 18:30.
6. The intake gate was cracked at ~19:17.
7. Speed-no-load Unit 1 started at ~19:51.
8. Speed-no-load Unit 1 stopped at ~20:36.

Testing of the units and the unit 2 load rejection took place on Dec. 8, 2017:

1. Unit 2 flush started at approximately 9:40am. Approximately 1 hour later the unit was shut down.
2. Unit testing started at 15:07.
3. Ramp up U2 to rough zone - 15:34.
4. Ramp up U2 to 40 MW – 15:42.
5. U2 Load Rejection – 15:53.
6. U1 & U2 Testing – Start U1 – 16:22.
7. Ramp up U2 – 16:45.
8. Control room stated both units in rough zone – 16:49.

9. 70 MW U1 – 16:55
10. Gate full open – 16:56
11. 70 MW U1 & U2 – 16:59 – Testing complete for Dec. 8th

Following the testing completed on Dec. 8th, the strain gauge data logger was left on-site and continued to log data until approximately Dec. 24th. The logger was shut down for a period until it was restarted on January 11th. For January 11th, the logger collected data for approximately 7 hours before it went offline.

A.3 Data Analysis

NRC installed 3-element rectangular rosettes, the strain gauges in the rosette has 1 gauge at each 0°, 45°, and 90° positions. Strain values for the rosette are normally denoted ε_A, ε_B, and ε_C. Due to the configuration that NRC installed the gauges, they denoted each gauge with _A, _C, or _H, for axial, combination, and hoop strain values. The naming convention for a strain gauge is as follows:

15_T65_INT_P00_A = [Channel]_[Can]_[internal(INT) or external(EXT)]_[P – positive, N-negative for angle]_[A-Axial,C-Combination,H-hoop].

Hatch received the strain gauge data from the NRC in the format of Microsoft Excel binary files at a sample rate of 50 Hz. The following calculations were performed on the data and the data was graphed accordingly:

1. Principal stresses were calculated from the strain readings from each 3-element rectangular rosette:

$$\sigma_1 = E\left[\frac{\epsilon_A + \epsilon_C}{2(1-\nu)} + \frac{1}{2(1+\nu)}\sqrt{(\epsilon_A - \epsilon_C)^2 + (2\epsilon_B - \epsilon_A - \epsilon_C)^2}\right]$$
$$\sigma_2 = E\left[\frac{\epsilon_A + \epsilon_C}{2(1-\nu)} - \frac{1}{2(1+\nu)}\sqrt{(\epsilon_A - \epsilon_C)^2 + (2\epsilon_B - \epsilon_A - \epsilon_C)^2}\right]$$

Figure A-5: Principal Stress Equations

2. The principal angle was calculated from the strain readings:

$$\tan 2\phi = \frac{2\epsilon_B - \epsilon_A - \epsilon_C}{\epsilon_A - \epsilon_C}$$

Figure A-6: Principal Angle Equation

3. The circumferential and axial stresses were calculated from both the strain values and the principal angle:

$$\sigma_{xx} = \frac{E}{(1+\nu)(1-2\nu)}\left[(1-\nu)\epsilon_{xx} + \nu(\epsilon_{yy}+\epsilon_{zz})\right]$$
$$\sigma_{yy} = \frac{E}{(1+\nu)(1-2\nu)}\left[(1-\nu)\epsilon_{yy} + \nu(\epsilon_{xx}+\epsilon_{zz})\right]$$

$$\gamma_{xy} = 2\epsilon_B - \epsilon_A - \epsilon_C$$

$$\tau_{xy} = \frac{E}{2(1+\nu)}\gamma_{xy}$$

$$\begin{aligned}
\sigma_{x'x'} &= \sigma_{xx}\cos^2\theta + \sigma_{yy}\sin^2\theta + 2\tau_{xy}\sin\theta\cos\theta \\
&= \frac{\sigma_{xx}+\sigma_{yy}}{2} + \frac{\sigma_{xx}-\sigma_{yy}}{2}\cos 2\theta + \tau_{xy}\sin 2\theta \\
\sigma_{y'y'} &= \sigma_{yy}\cos^2\theta + \sigma_{xx}\sin^2\theta - 2\tau_{xy}\sin\theta\cos\theta \\
&= \frac{\sigma_{yy}+\sigma_{xx}}{2} + \frac{\sigma_{yy}-\sigma_{xx}}{2}\cos 2\theta - \tau_{xy}\sin 2\theta \\
\tau_{x'y'} &= \sigma_{yy}\cos\theta\sin\theta - \sigma_{xx}\cos\theta\sin\theta + \tau_{xy}(\cos^2\theta - \sin^2\theta) \\
&= \frac{\sigma_{yy}-\sigma_{xx}}{2}\sin 2\theta + \tau_{xy}\cos 2\theta
\end{aligned}$$

Figure A-7: Axial and Circumferential Stress Equations

4. A Fourier frequency analysis was performed on various sections of the data to produce a plot showing the frequencies of vibration/pulsation and the spectral amplitude of the vibration. The analysis used a Fourier Fast Transform algorithm that is available in Microsoft Excel or many data analysis oriented programming languages. As the principal, circumferential, and axial stresses are directly proportional to the internal pressure of the penstock, only the T33 pressure frequency analysis and plots will be discussed in the following sections. The frequencies are identical for the T33 stresses and are very similar for T65. There is a slight variation for the T65 stresses due to the distance between the cans and the differing backfill between the locations.

A.3.1 Baselines and Completion of Backfilling

As expected, the baseline readings for each section of the penstock showed essentially zero stress.

The calculated stresses for the sections of T33, T35, T36, and T65 showed a slight increase in stress upon completion of the backfilling, but these stresses were still very minimal in magnitude. See appendix A for the baseline and completed backfill plots.

A.3.2 Water Up

Analysis from the T33 bottom hold point data shows minimal stress increase as the water reached the bottom of can T33.

The T65 bottom hold point data shows minimal stress increase as the water reached the bottom of can T65.

The T33 top hold point data shows, once again, minimal stress increase as the water neared the top of can T33.

The T65 top hold point data also shows minimal stress increase as the water neared the top of can T65. Slight variations in stress can be noted for can T33, T35, and T36 but are still of minimal magnitude, see Figure A-8.

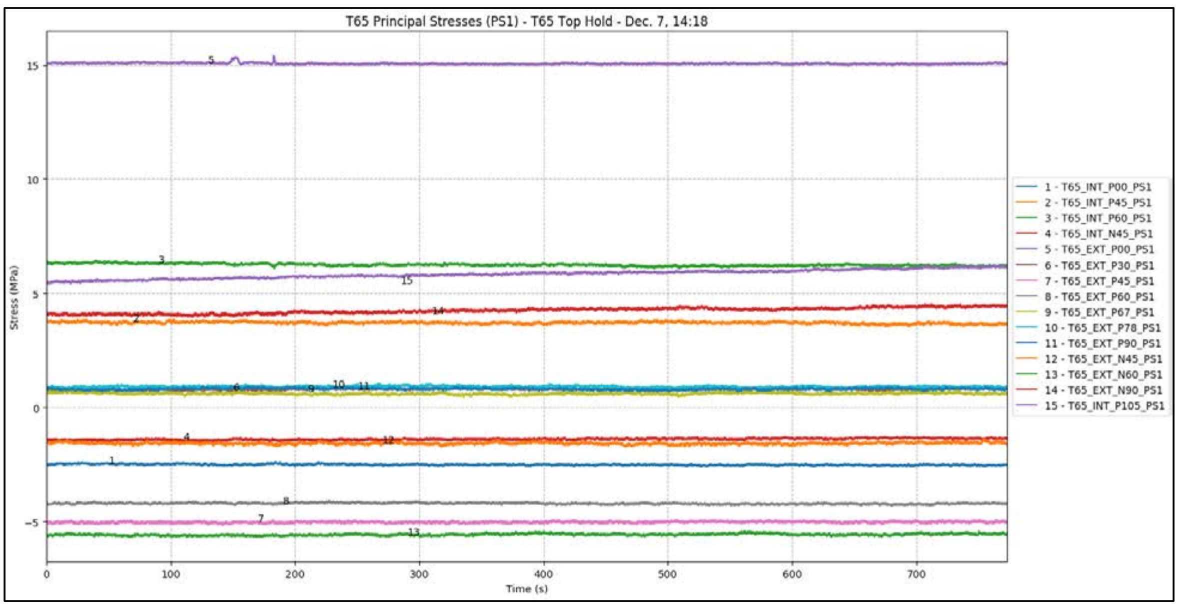


Figure A-8: T65 Principal Stress 1 (Circumferential) – T65 Top Hold Point (223 psi)

With the penstock reaching a full state, stresses are noted to increase by a considerable magnitude upon pressurization, see Figure A-9. The location of the strain rosette indicating the point of highest circumferential stress is on can T65, adjacent to the longitudinal weld seam (T65_INT_P105). The rosette also shows this location to have the highest axial stress. Cans T33, T35, and T36 also show increases in circumferential and axial stresses but are not near the maximum values for the rosette located in T65 adjacent to the longitudinal weld seam.

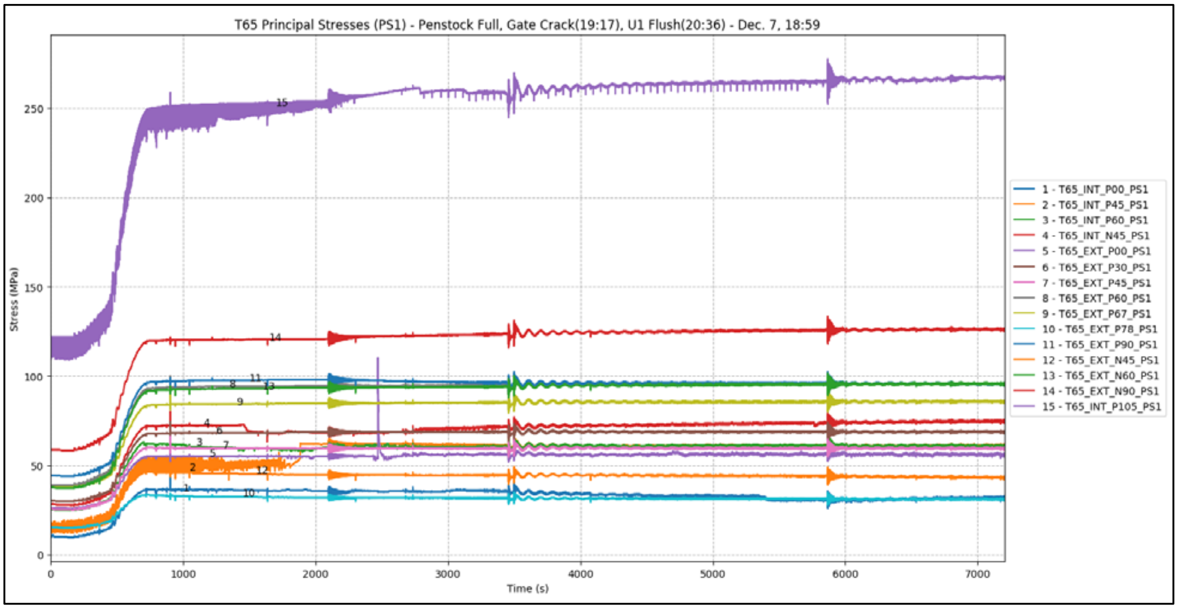


Figure A-9: T65 Principal Stress 1 (Circumferential) - Completion of Water Up to Full Penstock

It should be noted that the rosette hoop gauge T65_INT_P105_H started to have water intrusion and was compromised hours just after water up was completed. On the above graph, some noise is shown for T65_INT_P105_PS1 caused by water starting to infiltrate into the gauge. As only 1 of 3 gauges of the rosette was compromised and as this location has the highest stresses, one of the two remaining gauges, T65_INT_P105_C, was used with an extrapolation equation to plot the missing data for T65_INT_P105_H. Using the data from water up when all gauges of the T65_INT_P105 rosette were collecting data, a plot of T65_INT_P105_C vs. T65_INT_P105_H was produced. Using this plot, a linear best fit equation was produced and this equation was used to plot the T65_INT_P105_H values going forward. As the relation between the combined and hoop gauge is linear, the best fit produced an R^2 value of 0.998 for the plot.

Two pressure transducers were installed, one at the top of can T33, and one at the top of can T65. During initial testing, both transducers showed good readings and appeared to be adequately working. Upon water up, the transducer at T65 started producing inaccurate readings and was deemed compromised.

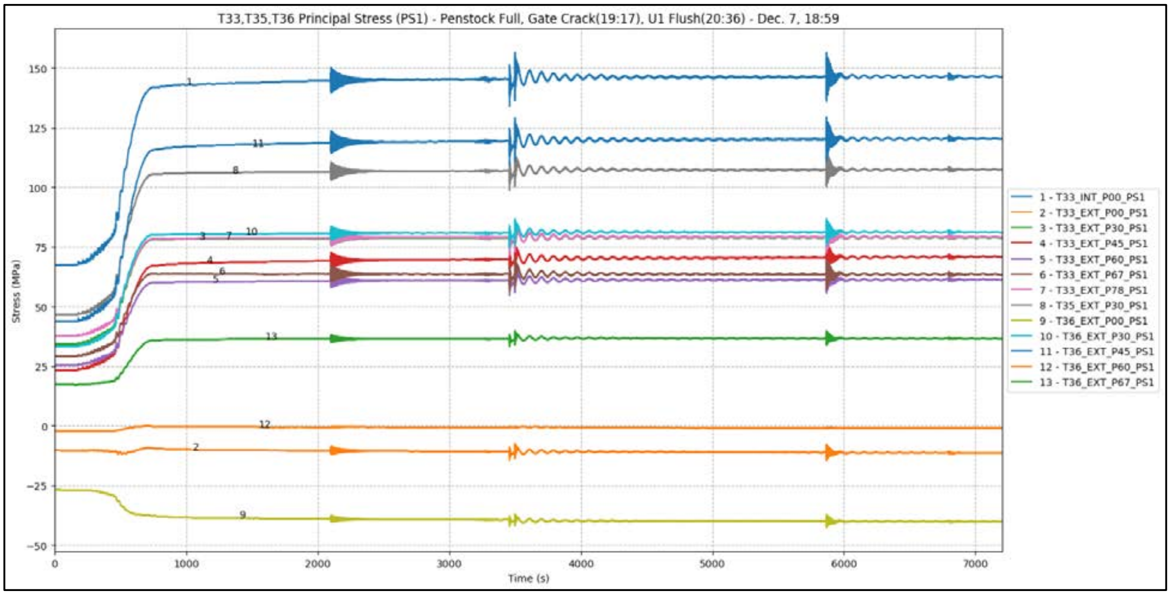


Figure A-10: T33, T35, T36 Principal Stress 1 (Circumferential) – Completion of Water up to Full Penstock

A.3.3 Unit Testing – Dec. 8, 2017

Unit testing started on Dec. 8, 2017 at approximately 3:07 and proceeded according to the Penstock No. 1 Test Plan (H356043-00000-240-230-0001). Data analyzed by Hatch was from two different loggers. NRC provided the Strain Gauge (SG) Logger data and NL Hydro provided the Plant Logger data. The data from the SG Logger consisted of the strain data from 29 rosettes and the pressure data captured by the transducer at T33. The Plant Logger captured the following data:

- Penstock Pressure (Unit 1), located near the spherical valve (psi)
- Unit 2 Scroll Case Pressure (psi)
- Unit 2 MW (MW)
- Headpond Level (m)
- Unit 2 Voltage (kV)
- Unit 2 Speed (RPM)
- B1T2 Status (V)
- Wicket Gate position (%)

Note: At the time of the unit testing, The Plant Logger and SG Logger clocks were not synched. All graphs of data from the two loggers are approximately synched.

The data acquired from Dec. 8th will be discussed for the following slots:

- Unit 2 starting
- Unit 2 at speed no load
- Unit 2 rough zone
- Unit 2 load rejection
- Unit 1 and Unit 2 rough zone operation
- Unit 1 and Unit 2 operation outside rough zone

For the Dec. 8th data, strain gauge 19_T65_INT_N45_C was compromised, therefore the same interpolation (with the exception of C and H gauges reversed) was used as section 3.2 for the T65_INT_P105 rosette.

Stresses for the unit testing range from approximately -50 MPa (PS2 Axial at the T36_EXT_P00 gauge) to a maximum of approximately 303 MPa (PS1 at T65_INT_P105) during load rejection. The average for T65_INT_P105 (PS1 – circumferential) during the unit testing was approximately 280 MPa, this gauge had the highest stress as it was ~5mm above one of the longitudinal weld seams of can T65.

The location of highest stress for T33, T35, and T36 was T33_INT_P00 which had an average of 149 MPa. The T33 pressure had an average of 37.91 psi throughout the testing.

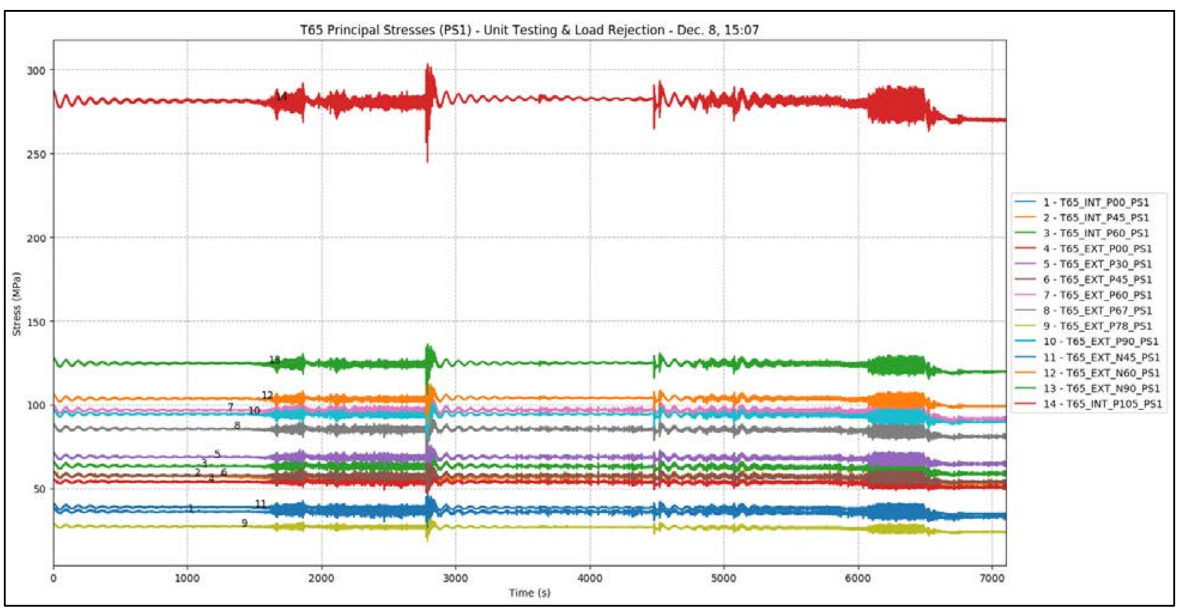


Figure A-11: T65 Principal Stress 1 (Circumferential) – Unit Testing and Load Rejection

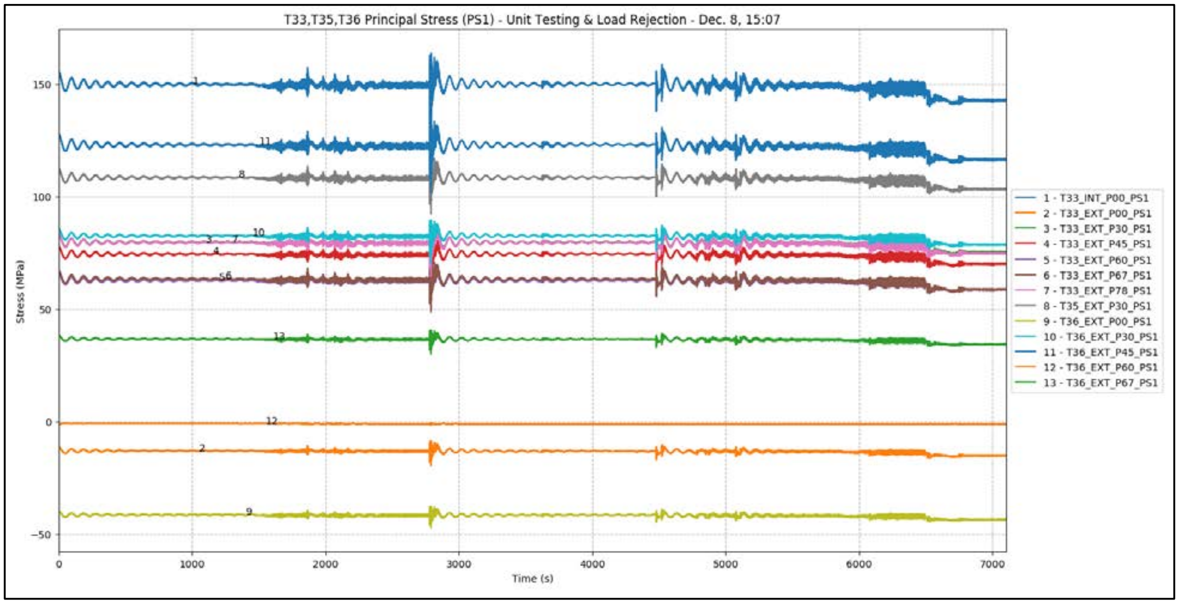


Figure A-12: T33, T35, & T36 Principal Stress 1 (Circumferential) – Unit Testing & Load Rejection

A.3.3.1 Unit 2 Starting

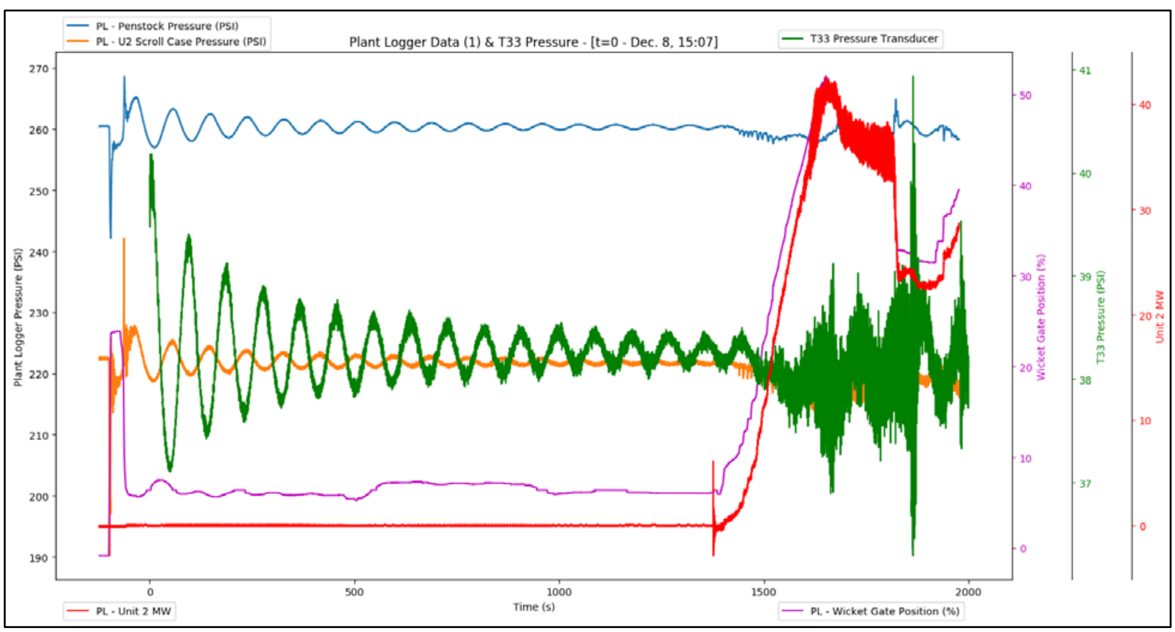


Figure A-13: Plant Logger Data and T33 Pressure – t = 0, Dec. 8, 15:07

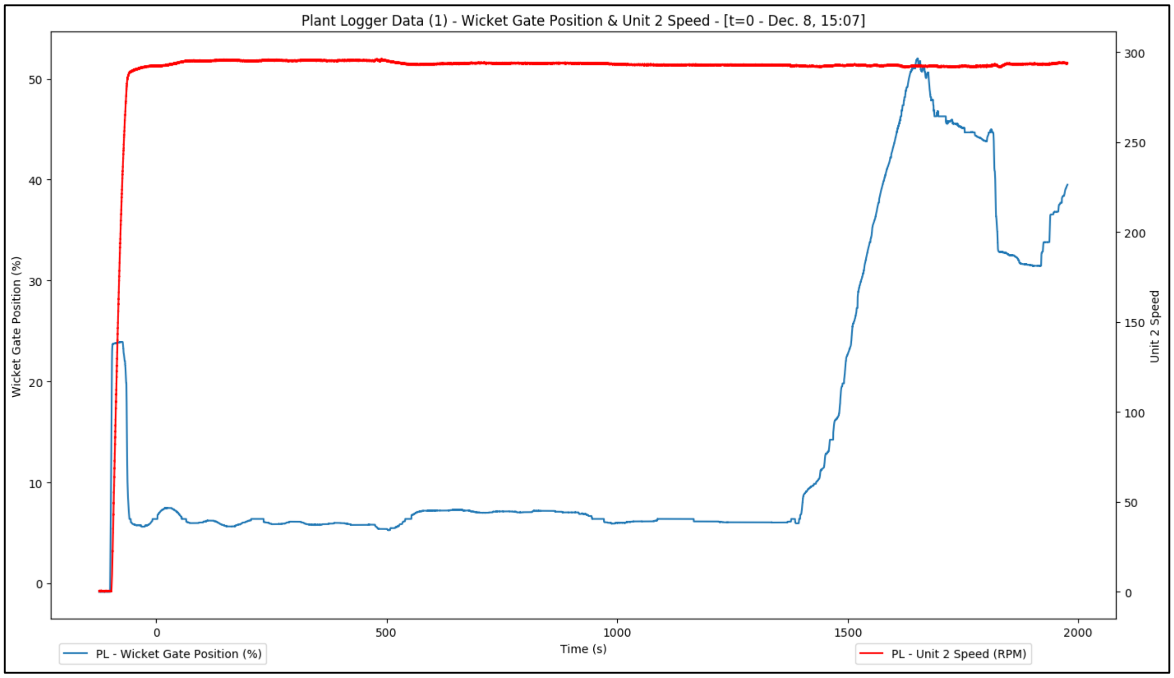


Figure A-14: Unit 2 Start & Speed No Load – Wicket Gate Position & Unit 2 RPM

From the Plant Logger data, Unit 2 is shown to start just prior to the start of data recording for the SG Logger. The Unit 2 wicket gates open simultaneously with the unit starting at speed no load. The plant logger data did not capture the spherical valve opening. A drop in pressure is noted upon the opening of the wicket gates to ~25%, followed by a small spike in pressure as the wicket gates are closed to ~8% and speed no load begins. The wicket gates open to ~25% to accelerate the fluid, once the unit reaches a speed of ~300 RPM, the governor closes the wicket gates to ~8% to maintain 300 RPM while the unit operates under a no load condition.

A.3.3.2 Unit 2 Speed No Load

Unit 2 speed no load takes place for approximately 20 minutes, see Figure A-13 time 0s to approximately 1375s. A decaying pulsation can be noted on the graph. The Fourier frequency analysis shows this to occur at approximately 0.011-0.013 Hz. This corresponds with the time period of the surge tank at approximately 81.72s. The spectral amplitude of the other frequencies during this time are very minimal, although one other frequency to note that is almost negligible is the 0.39-0.40 Hz, which corresponds to the critical penstock period of approximately 2.54s.

Table A-1: U2 Speed No Load – T33 Pressure, T65_INT_P105_PS1, & T33_INT_P00_PS1 Average, Maximum, and Minimum

Unit 2 Speed No Load (0-1375s)			
	T33 Pressure (PSI)	T65_INT_P105_PS1 (MPa)	T33_INT_P00_PS1 (MPa)
Average	38.27	281.24	149.84
Max	40.18	287.37	155.12
Min	37.1	276.96	146.69

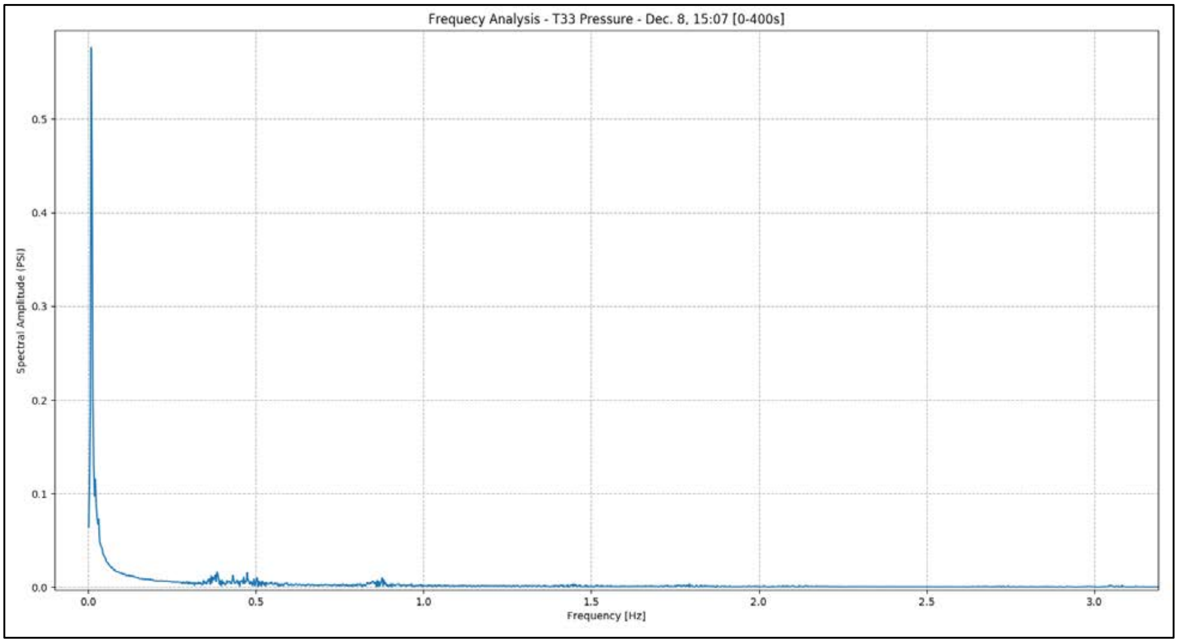


Figure A-15: Frequency Analysis – T33 Pressure – Unit 2 Speed No Load

A.3.3.3 Unit 2 Rough Zone

The unit 2 rough zone is displayed in Figure A-16 from approximately 1590 – 1825s. As unit 2 ramps up to approximately 29 MW, there is a notable increase in system vibration. The rough zone is very evident from 30-40 MW. As the load on the unit is dropped shortly after ~1800s, to ~24 MW the roughness decreases significantly.

From a Fourier analysis of 40s of rough zone operation (T33 Pressure), multiple frequencies are notable. The frequency showing the highest spectral amplitude is approximately 1 Hz. Other notable frequencies are approximately 0.025, 0.4, 0.9, 1.8, 2.05, and 3.1 Hz. The ~1 Hz frequency is caused by the turbulent “draft tube rope” vorticity and vortex shedding that occurs as the fluid passes through the runner and travels downstream through the draft tube.

Table A-2: U2 Rough Zone – T33 Pressure, T65_INT_P105_PS1, & T33_INT_P00_PS1 Average, Maximum, and Minimum

Unit 2 Rough Zone (1590-1825s)			
	T33 Pressure (PSI)	T65_INT_P105_PS1 (MPa)	T33_INT_P00_PS1 (MPa)
Average	38.04	280.29	149.32
Max	39.12	288.32	152.3
Min	36.89	270.19	146.19

Table A-3: T33 Pressure Frequency Analysis – U2 Rough Zone

T33 Pressure - Frequency	
Dec. 8, 15:07 [1630-1670s]	
Frequency (Hz)	Spectral Amplitude (psi)
0.025	0.092881448
0.875	0.068069286
0.95	0.090820694
0.975	0.111941205
1	0.188703218
1.025	0.258205905
1.05	0.107910484
1.1	0.055916074
1.825	0.060897873
1.85	0.069054319
1.875	0.054918779
2.025	0.09520275
2.05	0.085497467
2.075	0.098155368
2.1	0.091207676
3.05	0.051583064
3.075	0.102168248
3.1	0.051883042
3.125	0.061452745

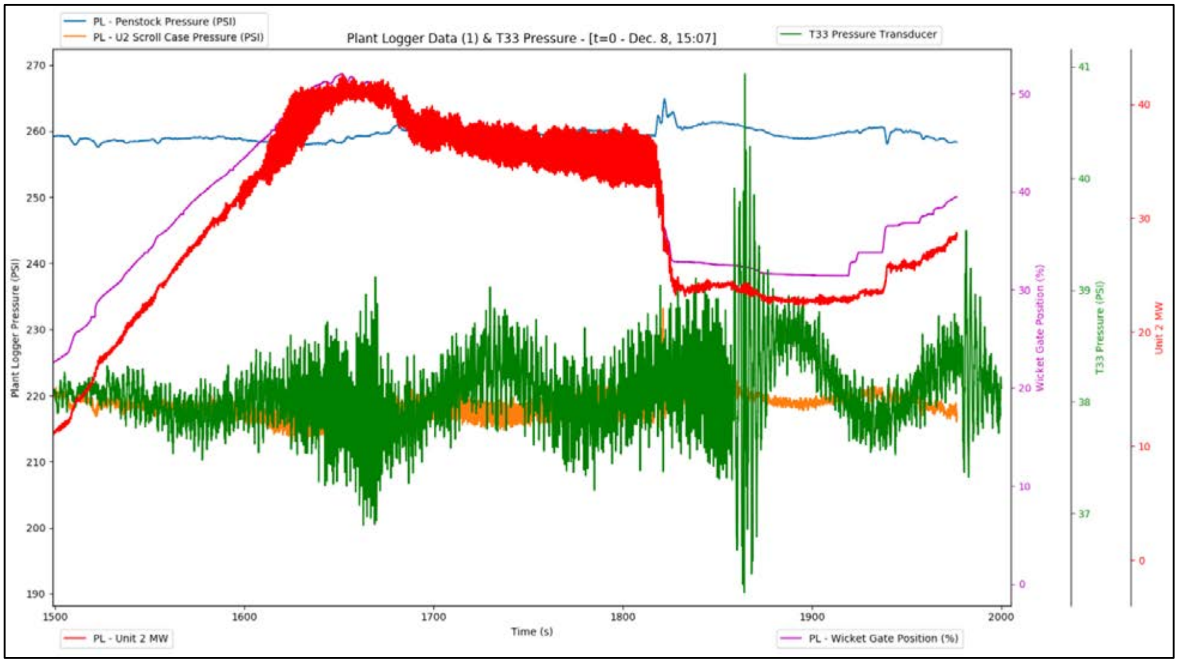


Figure A-16: Unit 2 Rough Zone

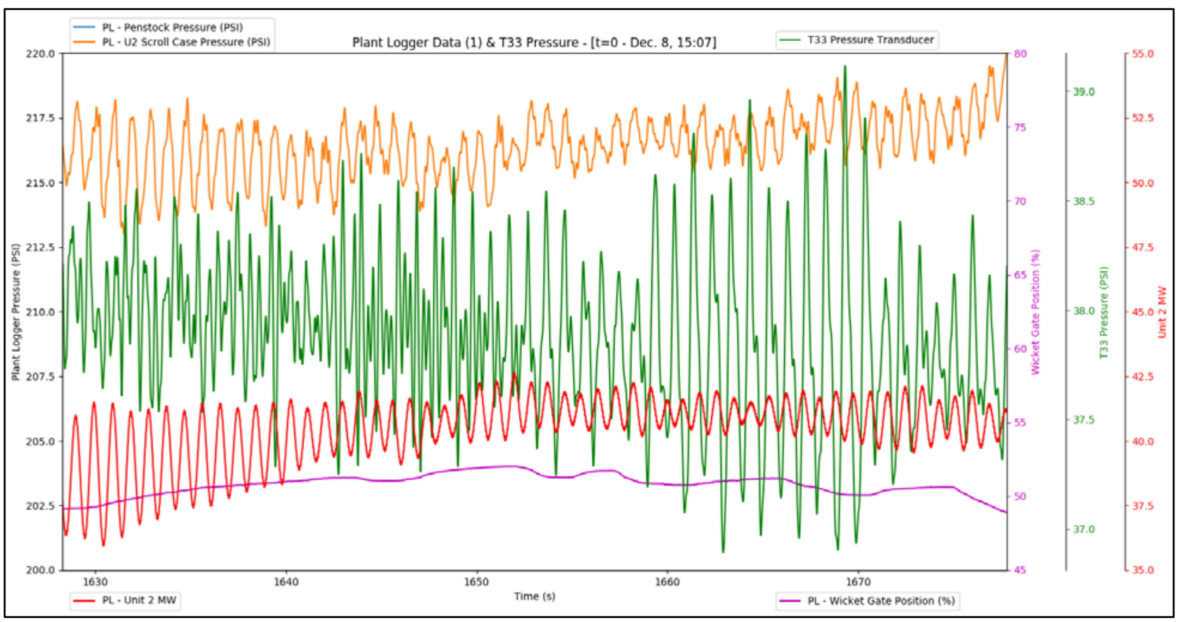


Figure A-17: Unit 2 Rough Zone – 1630-1670s

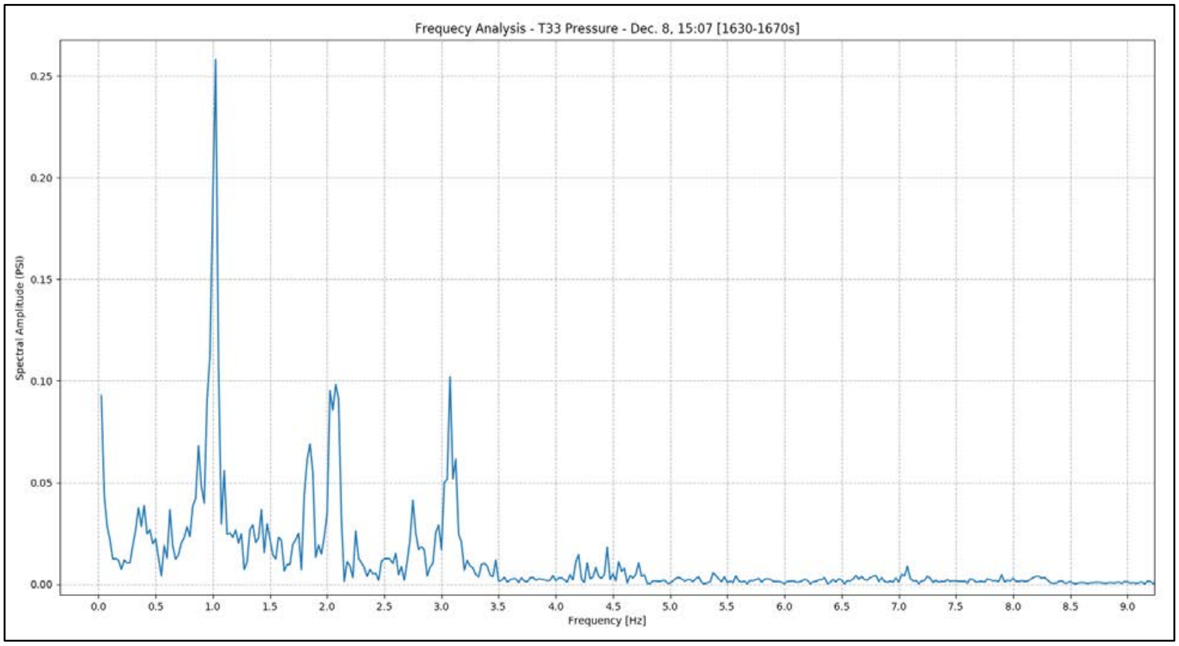


Figure A-18: Frequency Analysis – T33 Pressure – Unit 2 Rough Zone (40s)

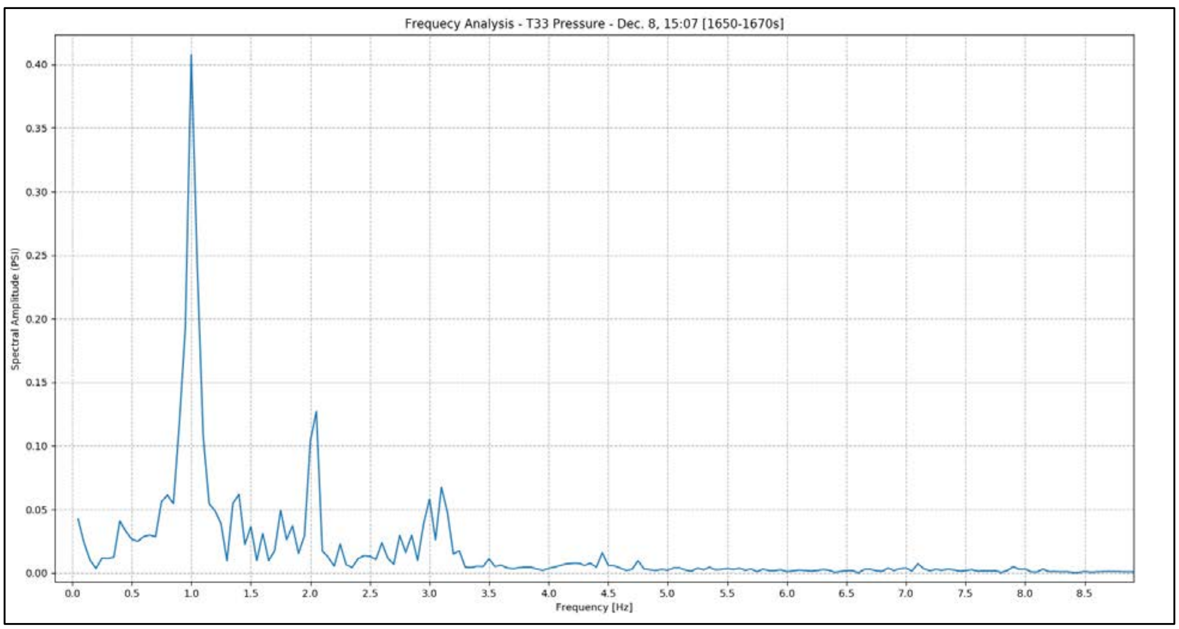


Figure A-19: Frequency Analysis – T33 Pressure – Unit 2 Rough Zone (20s)

A.3.3.4 Unit 2 Load Rejection

The Unit 2 Load rejection occurred at approximately 15:53 on Dec. 8th. A notable spike in pressure of approximately 35.98 psi occurred in the powerhouse (Unit 2 Scroll Case Pressure). The pressure transducer at T33 showed an immediate increase of approximately 3.81 psi followed by an increasing oscillation that reached a maximum transducer reading of 43.19 psi and a minimum reading of 30.02 psi, the oscillation then started decaying.

The highest location of stress T65_INT_P105 showed a principal stress 1 (circumferential) increase of approximately 18.66 MPa followed by the increasing oscillation with a maximum reading of 303.33 MPa, and a minimum of 244.62 MPa before decaying. The highest stress location on T33, T35, and T36 is T33_INT_P00 which had a maximum principal stress 1 of 163.67 MPa and a minimum PS1 value of 126.67 MPa.

The frequency analysis (T33, 20s interval at load rejection) shows the highest spectral amplitude (PSI) to occur at approximately 0.4 Hz, the critical penstock period. Following the load rejection (~100s), the most notable frequency becomes ~0.01 Hz, the time period for the surge tank, followed by the same 0.4 Hz frequency as before.

Table A- 4: U2 Load Rejection – T33 Pressure, T65_INT_P105_PS1, & T33_INT_P00_PS1 Average, Maximum, and Minimum

Unit 2 Load Rejection (2775-2815s)			
	T33 Pressure (PSI)	T65_INT_P105_PS1 (MPa)	T33_INT_P00_PS1 (MPa)
Average	38.12	281.17	149.63
Max	43.19	303.33	163.67
Min	30.02	244.62	126.67

Table A-5: T33 Pressure Frequency Analysis – U2 Load Rejection

T33 Pressure - Frequency - U2 Load Rejection	
Dec. 8, 15:07 [2768-2788s]	
Frequency (Hz)	**Spectral Amplitude (psi)**
0.1	0.117836462
0.2	0.221557221
0.25	0.279837902
0.3	0.322991067
0.35	1.233376034
0.4	1.783121443
0.45	1.480010302
0.5	0.552094744
0.55	0.393216047
0.6	0.361383451
0.65	0.13087565
0.7	0.314011571
0.75	0.188067903
0.8	0.253131598
0.85	0.230544369
0.9	0.182957888
0.95	0.155774393
1.05	0.079321091
1.1	0.100126494
2.15	0.052069859

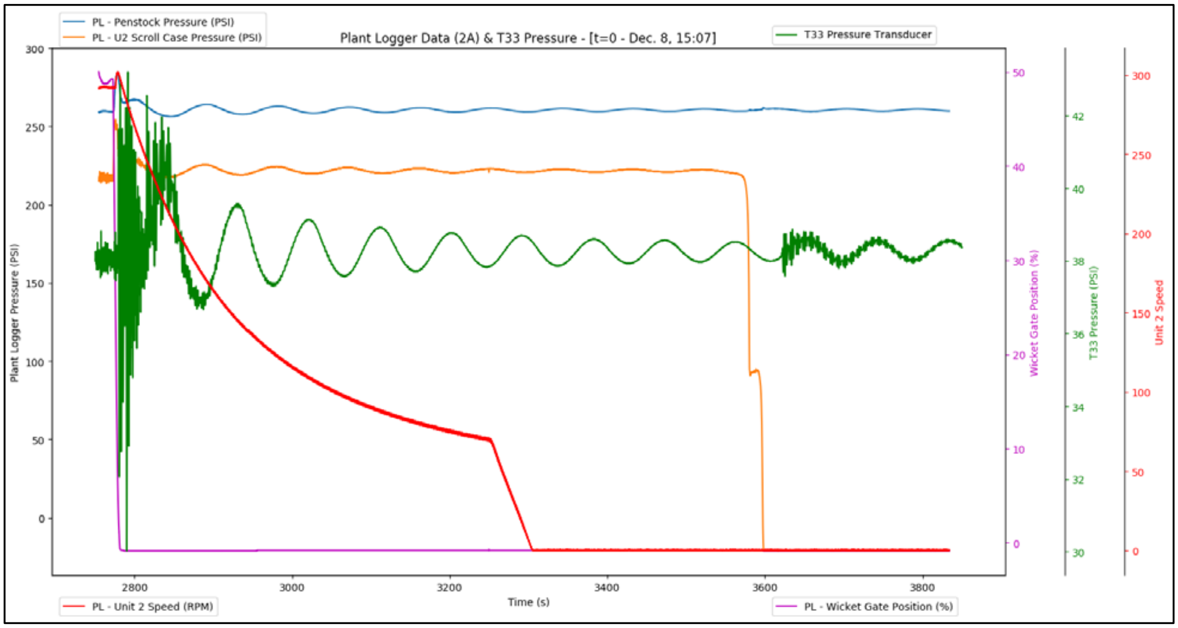


Figure A-20: Unit 2 Load Rejection

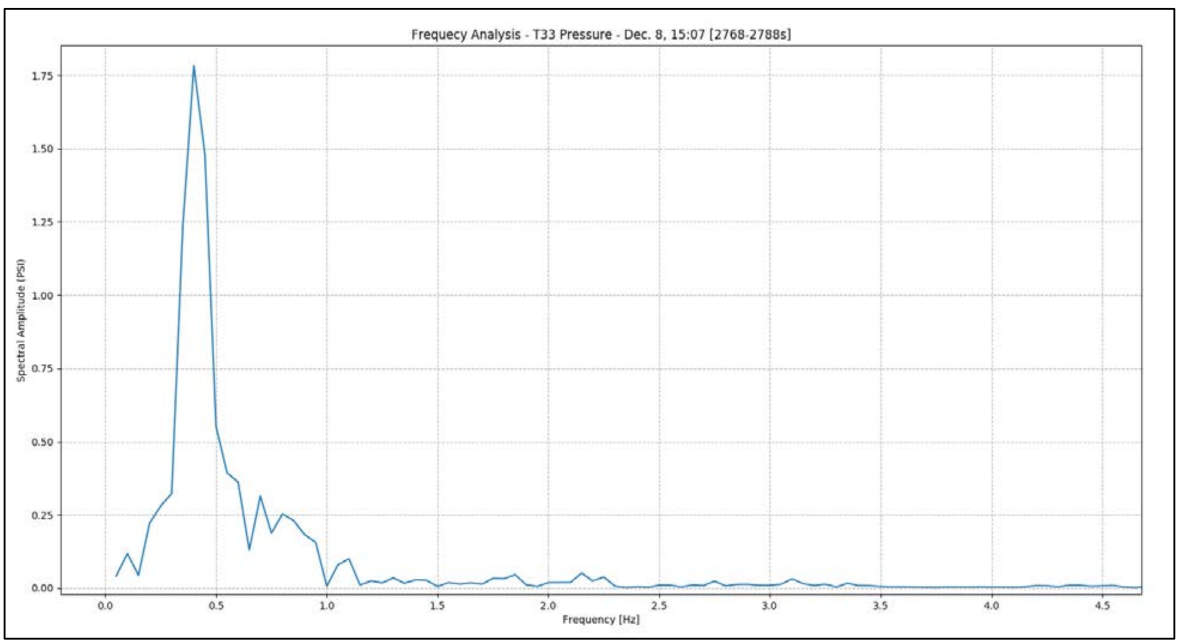


Figure A-21: Frequency Analysis – T33 Pressure – Unit 2 Load Rejection (20s)

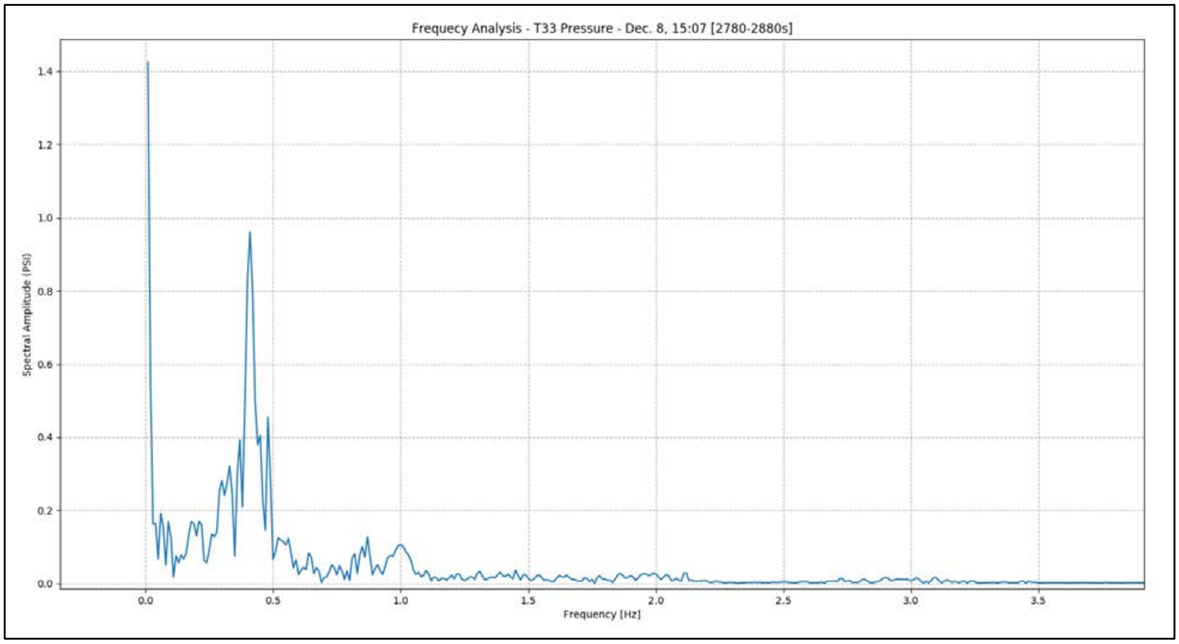


Figure A-22: Frequency Analysis – T33 Pressure – Load Rejection Response (100s)

Another unique area to note on Figure A-20 is ~3622-3850s, this is the time after the closure of the Unit 2 Spherical Valve, as noted by the loss of pressure from the Unit 2 Scroll Case Pressure Transducer. As the spherical valve closes, a small pulsation is sent through the penstock as shown by the T33 Pressure Transducer. The pulsation frequencies are as shown in Table A-6. The spectral amplitude caused by the pulsation is almost negligible.

Table A-6: T33 Pressure Frequencies – Unit 2 Spherical Valve Closing After Load Rejection

T33 Pressure - Frequency - U2 SV Close after Load Rejection	
Dec. 8, 15:07 [3622-3850s]	
Frequency (Hz)	**Spectral Amplitude (psi)**
0.004385965	0.085367594
0.00877193	0.18044968
0.013157895	0.179038206
0.01754386	0.053271335
0.021929825	0.03356087
0.355263158	0.026581902
0.359649123	0.033084492
0.364035088	0.042526185
0.368421053	0.071909627
0.372807018	0.038055164
0.478070175	0.025632904
0.48245614	0.036864767
0.486842105	0.072701789

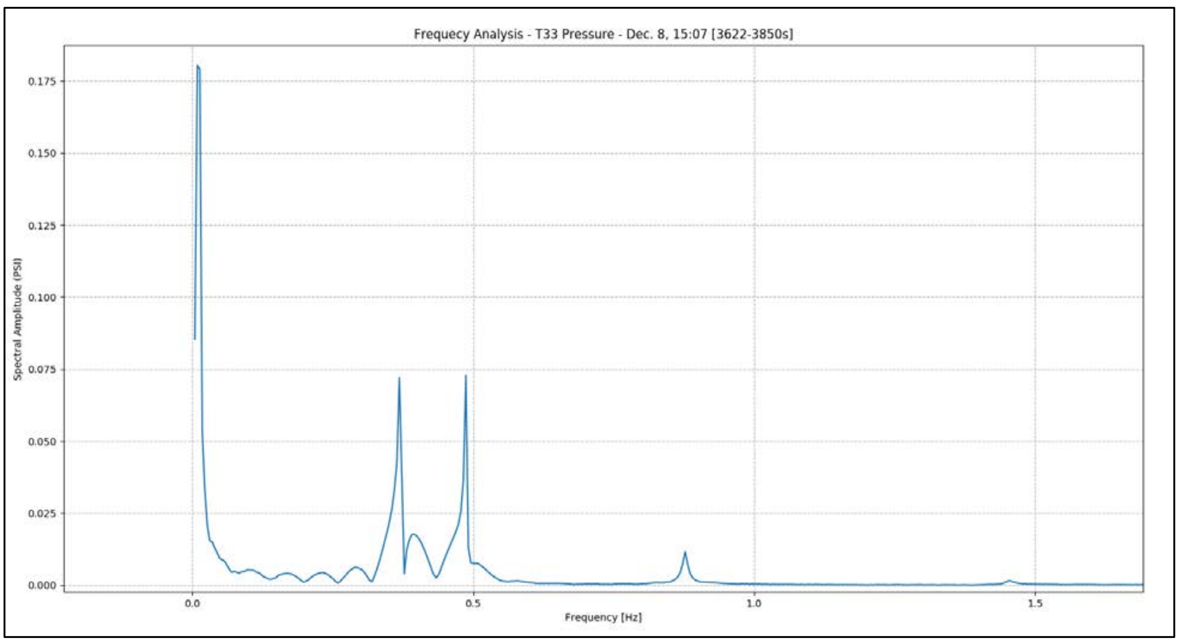


Figure A-23: Frequency Analysis – T33 Pressure – U2 Spherical Valve Closing After Load Rejection

A.3.3.5 U1 and U2 Rough Zone Operation

The 2 unit rough zone occurred at approximately 16:49 on Dec 8th. The plant logger data provided ~230s of 2 unit rough zone operation. The 2 unit rough zone occurred with unit 2 at approximately 29 MW.

The Fourier analysis (T33 Pressure) for the 2 unit rough zone versus the 1 unit rough zone, shows more pronounced frequencies with less noise. Once again, the most notable frequency is approximately 1.0 Hz, followed by 2.0, 1.8, 1.3, 0.9, 0.7, and 0.4 Hz. The highest spectral amplitude is approximately 0.704 psi for the 1.0 Hz vibration.

Comparing the absolute or average values of the unit 1 and unit 2 rough zone and the unit 2 rough zone, the average pressure at T33 is lower for the 2 unit rough zone. This is to be expected as the flow, and therefore velocity, is increased for 2 unit operation resulting in a greater pressure drop throughout the penstock (dynamic head decreasing with increasing flow).

Table A-7: T33 Pressure, T65_INT_P105_PS1, & T33_INT_P00_PS1 for Unit 1 & Unit 2 Rough Zone

Unit 1 & Unit 2 Rough Zone (6125-6450s)			
	T33 Pressure (PSI)	**T65_INT_P105_PS1 (MPa)**	**T33_INT_P00_PS1 (MPa)**
Average	37.54	279.12	148.1
Max	39.2	290.44	152.6
Min	35.98	266.22	143.78

Table A-8: T33 Pressure Frequencies & Spectral Amplitudes for Unit 1 & Unit 2 Rough Zone

T33 Pressure - Frequency - U1 & U2 Rough Zone	
Dec. 8, 15:07 [6180-6200s]	
Frequency (Hz)	**Spectral Amplitude (psi)**
0.05	0.034874136
0.4	0.079282283
0.45	0.043840547
0.7	0.076458611
0.85	0.130661986
0.9	0.172735508
0.95	0.102447889
1	0.70419691
1.05	0.035349983
1.3	0.100395667
1.85	0.034828596
1.9	0.055162902
1.95	0.058945476
2	0.179936059
2.1	0.079249447
2.65	0.045209317
2.8	0.035964297
2.9	0.052633442
3	0.039251309
3.05	0.036311774
3.45	0.030606117

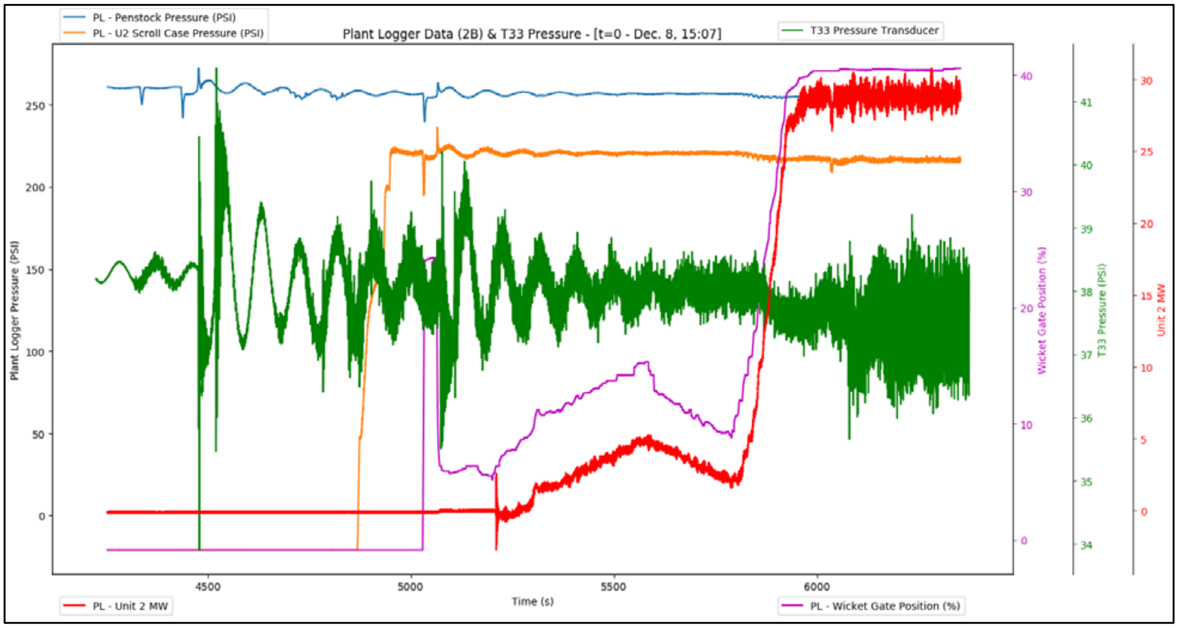


Figure A-24: Plant Logger Data & T33 Pressure – U1 & U2 Rough Zone

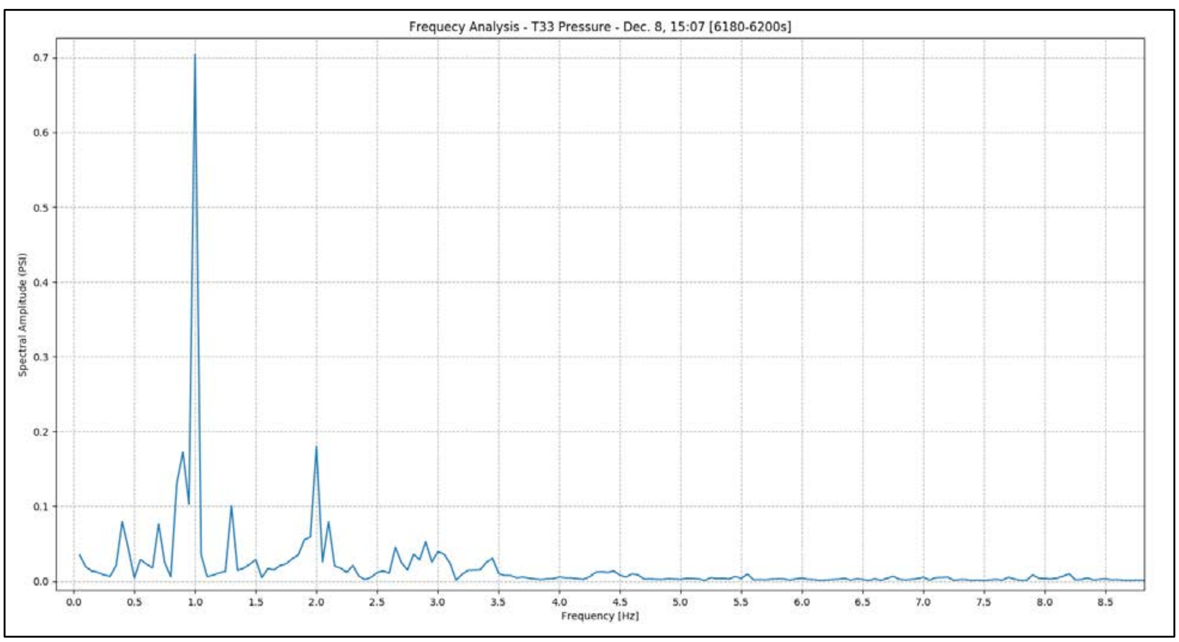


Figure A-25: Frequency Analysis – T33 Pressure – U1 & U2 Rough Zone

Referring to Figure A-26, unit 2 shows in increase in roughness as it passes through 27-28 MW. On Figure A-28, as unit 2 is ramped up to 70 MW, the roughness is very evident through to ~40 MW, and gradually starts to decrease until ~53 MW is reached and following that point the roughness is minimal. During testing, unit 1 reached 70 MW then unit 2 was ramped up immediately following.

A.3.3.6 U1 & U2 Operation Outside Rough Zone – 70 MW

Following the 2 unit rough zone, the units were ramped to approximately 70 MW. The 70 MW operation is quite smooth compared to the 2 unit rough zone. A vibration is still notable but is minimal compared to rough zone operation.

From the Fourier analysis (20s interval analyzed), the most notable frequency is 0.4 Hz. The spectral amplitude is considerably smaller, at ~0.076 psi which is 10% of the spectral amplitude for rough zone operation. Other notable frequencies also include 0.7, 1.6, 1.9, and 3.05 Hz, but the spectral amplitudes are almost negligible.

Table A-9: T33 Pressure, T65_INT_P105_PS1, & T33_INT_P00_PS1 for Unit 1 & Unit 2 70 MW Operation

Unit 1 & Unit 2 Operation Outside Rough Zone (70 MW) (6800-7050s)			
	T33 Pressure (PSI)	**T65_INT_P105_PS1 (MPa)**	**T33_INT_P00_PS1 (MPa)**
Average	35.63	269.96	142.61
Max	35.92	271.2	143.41
Min	35.39	268.57	141.9

Comparing T33 Pressure, and the highest stress points for T65 and T33 of the 70 MW operation and the rough zone, the T33 pressure is much less due to the increased flow of both units at a peak operating point resulting in decreased dynamic head. As the pressure is lower, the stresses are also lower as shown by T65_INT_P105_PS1 and T33_INT_P00_PS1. The decreased spectral amplitudes are also displayed in Table A-4, as both the max and mins are considerably smaller than Table A-7 for the 2 unit rough zone. Comparing the differential or amplitude between the maximum, average, and minimum, the 2 unit 70 MW operation is approximately 15% of the differential in the two unit rough zone.

Table A-10: T33 Pressure Frequencies & Spectral Amplitude for Unit 1 & Unit 2 - 70 MW Operation

T33 Pressure - Frequency - U1 & U2 ~70 MW	
Dec. 8, 15:07 [2768-2788s]	
Frequency (Hz)	**Spectral Amplitude (psi)**
0.35	0.02344908
0.4	0.075912927
0.45	0.038642885
0.5	0.026539181
0.55	0.013018671
0.65	0.011520902
0.7	0.023707081
0.75	0.015787861
0.8	0.015038223
0.85	0.015581806
0.9	0.011088838
0.95	0.012041834
1.55	0.011902587
1.6	0.015550114
1.65	0.011343933
1.7	0.013222011
1.75	0.010581412
1.85	0.015735313
1.9	0.025485501
2.8	0.01096312
2.85	0.011329448
2.9	0.012113623
3	0.010050805
3.05	0.016741819
4.35	0.010237795

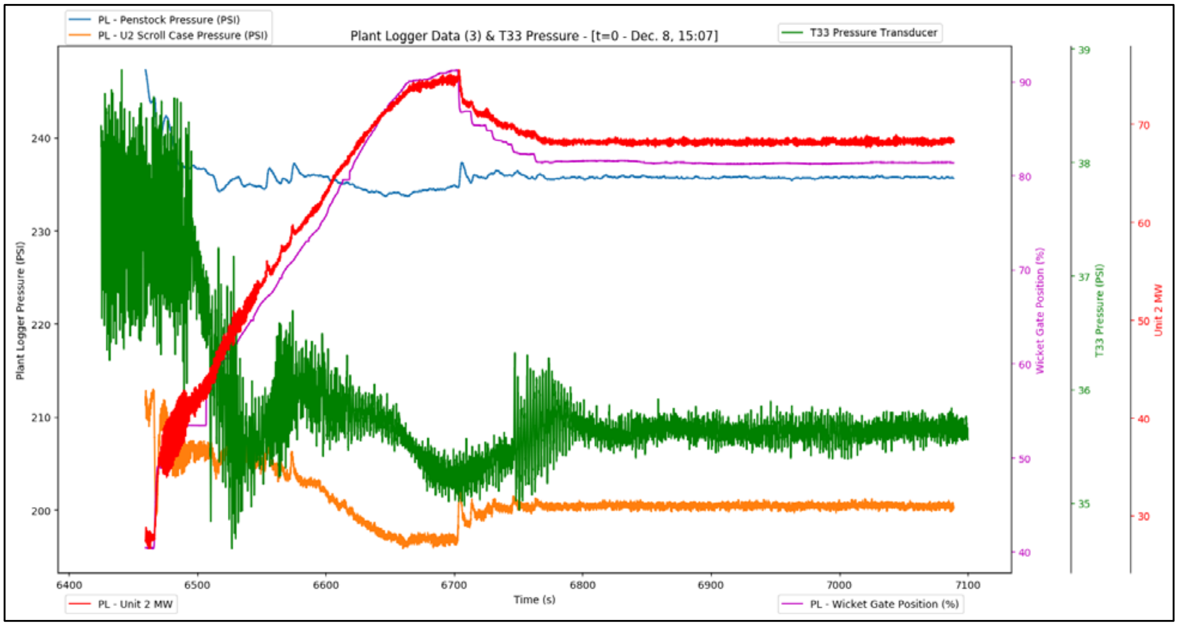


Figure A-26: Plant Logger Data & T33 Pressure – U1 & U2 at 70 MW Operation

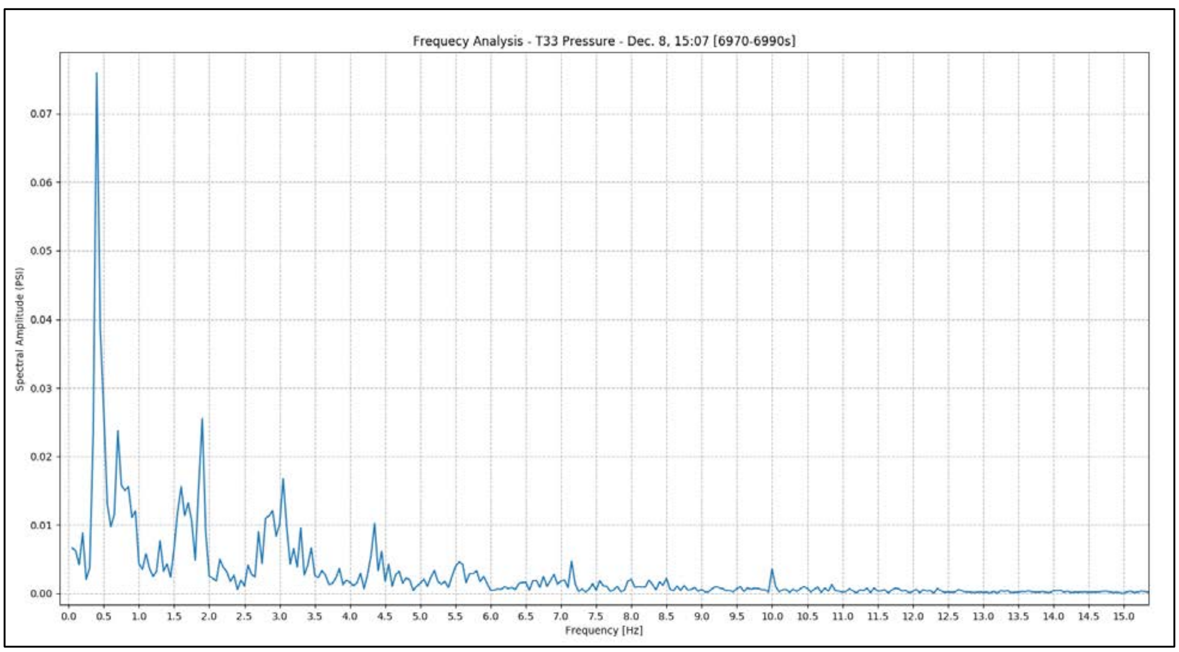


Figure A-27: Frequency Analysis – T33 Pressure – U1 & U2 at 70 MW Operation (20s)

A.4 Additional Data

Following the weeks of strain gauge installation, initial testing, water up, and unit load rejection testing on Dec 8, 2017, additional data was collected after the tests for analysis. Hatch determined the best course of action was to analyze dates for a comparison against the previously collected data to verify consistent operation of the penstock. NL Hydro dismantled the Plant Logger following the Dec. 8th testing therefore the only data afterwards is from the SG Logger. Multiple hours of data were given to Hatch for each of the dates Dec. 12, Dec. 13, Dec. 24, and Jan. 11. To minimize the data analysis, Hatch did a general plot of the T33 Pressure along with the various rosettes principal stresses to represent the range of stresses. After ensuring there were no abnormalities throughout the hours of data, an hour range was selected for comparison against the Dec. 8th data. As there is a direct correlation between the penstock pressure and the principal stresses, the T33 pressure will be used for further proceedings.

A.4.1 December 12

The Dec. 12th data had a generally smooth operation, therefore it best compares with the Dec. 8th out of rough zone data for 2 unit operation. The hour of 14:22 – 15:22 was selected as it had a smooth operation and zones with both generators ~>55 MW.

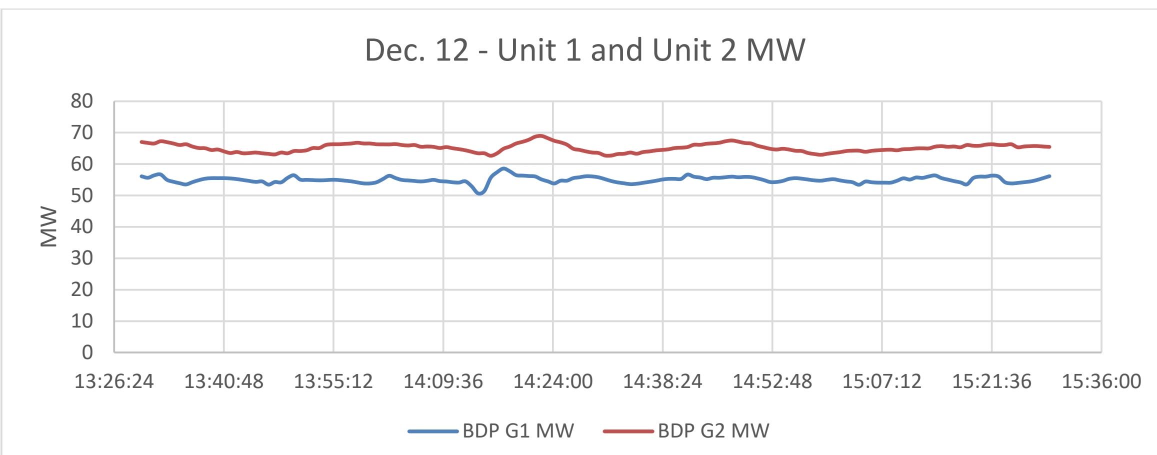


Figure A-28: December 12 – Unit 1 and Unit 2 MW

Comparing Table A-11 with Table A-9, the values are slightly higher on Dec. 12th. This is to be expected as Unit 1 is operating at a lower load and the dynamic head will result in a slightly higher pressure, and therefore higher stress as shown by the T65 and T33 values. The differential between the average, max, and min is also slightly larger than the Dec. 8th zone and is as expected due to Unit 1 operating at a lower load that is closer to rough zone operation.

Table A- 11: T33 Pressure, T65_INT_P105_PS1, & T33_INT_P00_PS1 for Dec 12, 14:2

December 12, 14:22 [0-3600s]			
	T33 Pressure (PSI)	**T65_INT_P105_PS1 (MPa)**	**T33_INT_P00_PS1 (MPa)**
Average	36.43	271.41	145.32
Max	37.1	274.08	146.68
Min	35.88	268.3	144.09

The frequency analysis (20s) of a sample from a 13 minute section of smooth operation (unit 1 and unit 2 were both greater than 55 MW) showed very similar frequencies and spectral amplitudes to the 2 unit ~70 MW (out of rough zone) operation on Dec. 8. The 0.4 Hz frequency was similar with a spectral amplitudes of ~0.07 psi.

Expanding the FFT analysis to the full ~13 minute section (2800-3600s), showed a ~0.01125Hz frequency (surge tank period) along with the ~0.4 Hz frequency.

Table A-12: Frequency Analysis – T33 Pressure – Dec. 12 (20s)

T33 Pressure - Frequency			
Dec. 8, 15:07 [6970 - 6990s]		**Dec. 12, 14:22 [3500-3520s]**	
Frequency (Hz)	**Spectral Amplitude (PSI)**	**Frequency (Hz)**	**Spectral Amplitude (PSI)**
0.35	0.02344908	0.25	0.021814647
0.4	0.075912927	0.4	0.072675528
0.45	0.038642885	0.45	0.073147052
0.5	0.026539181	0.5	0.034073608
0.55	0.013018671	0.55	0.024854846
0.65	0.011520902	0.6	0.022765097
0.7	0.023707081	0.8	0.028767595
0.75	0.015787861	0.9	0.02310961
0.8	0.015038223	0.95	0.024605553
0.85	0.015581806	1.85	0.024177285
0.9	0.011088838	1.9	0.04345635
0.95	0.012041834	2.9	0.024325991
1.55	0.011902587	3.1	0.026515033
1.6	0.015550114	3.15	0.033932016
1.65	0.011343933	3.2	0.041323918
1.7	0.013222011	3.25	0.020055666
1.75	0.010581412	3.3	0.024356288
1.85	0.015735313	3.5	0.021956522

T33 Pressure - Frequency			
Dec. 8, 15:07 [6970 - 6990s]		Dec. 12, 14:22 [3500-3520s]	
Frequency (Hz)	Spectral Amplitude (PSI)	Frequency (Hz)	Spectral Amplitude (PSI)
1.9	0.025485501		
2.8	0.01096312		
2.85	0.011329448		
2.9	0.012113623		
3	0.010050805		
3.05	0.016741819		
4.35	0.010237795		

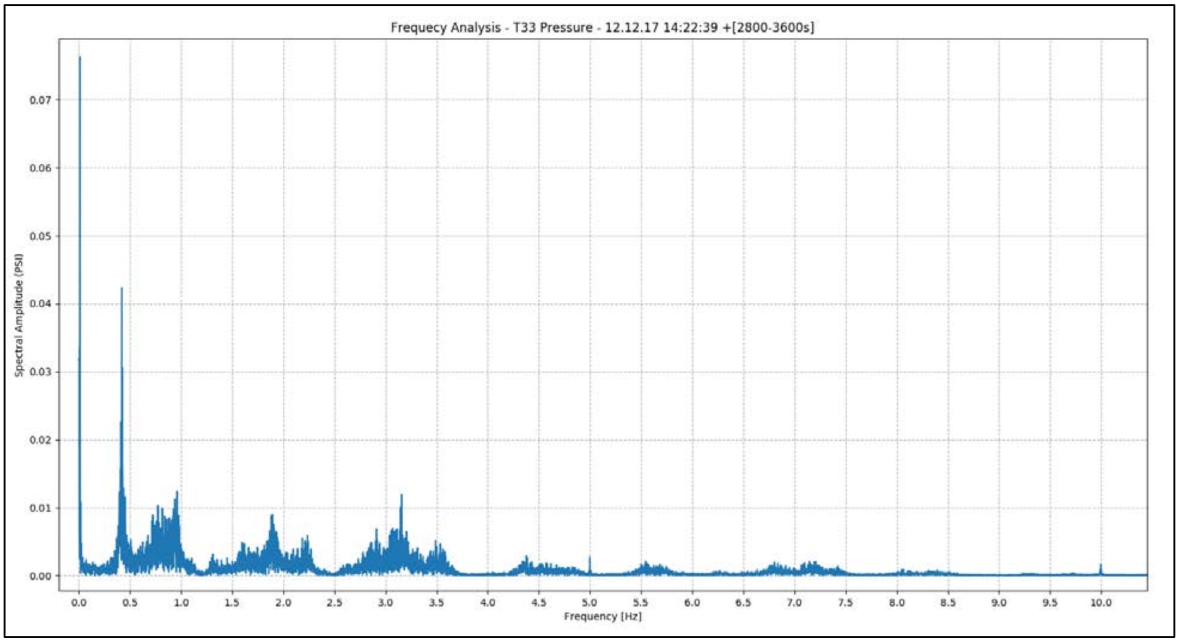


Figure A-29: Frequency Analysis – T33 Pressure – Dec. 12, 14:22 [2800-3600s]

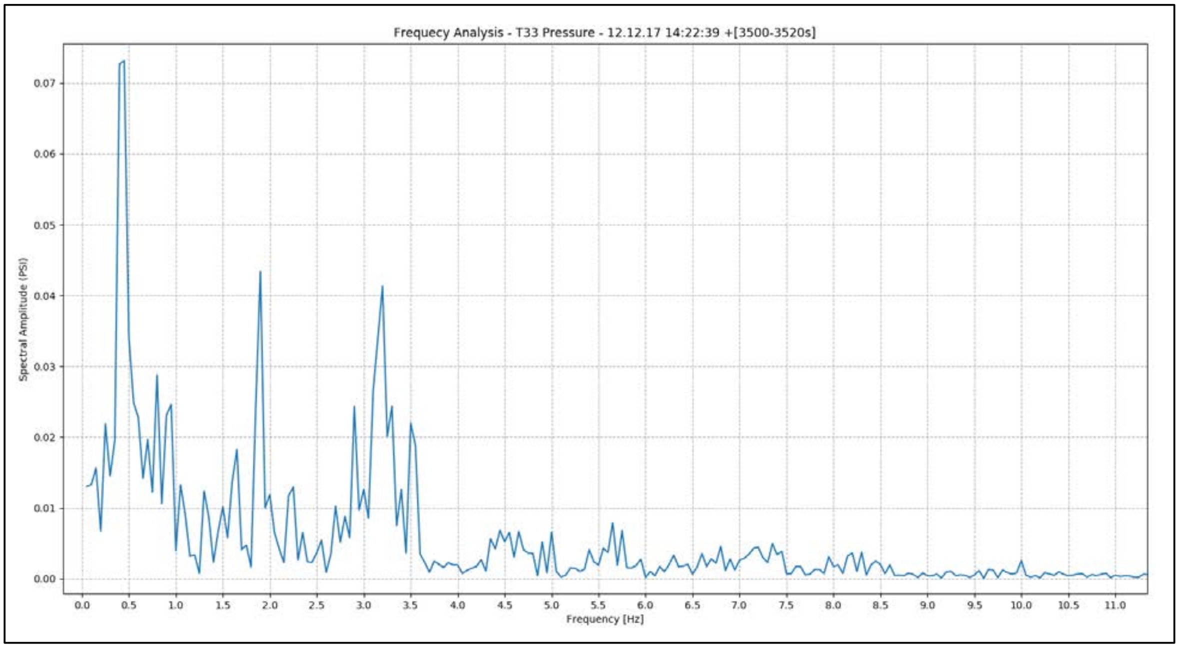


Figure A-30: Frequency Analysis – T33 Pressure – Dec. 12, 14:22 [3500-3520s]

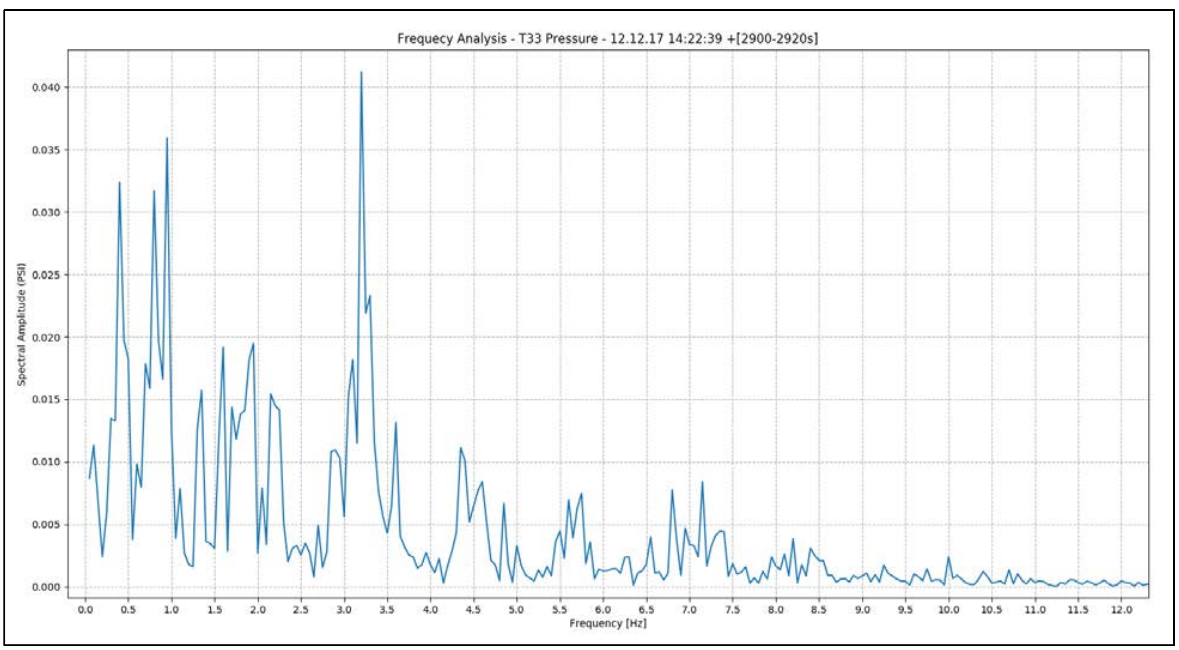


Figure A-31: Frequency Analysis – T33 Pressure – Dec. 12, 14:22 [2900-2920s]

A.4.2 December 13

For the Dec. 13th operation, two hours of data were analyzed with start times of 11:23:00, and 12:23:01. For comparison to the Dec. 8th data, Dec. 13th is under normal operation and therefore will have varying load on each of the generators but is comparable to Dec. 8th two unit operation outside of the rough zone when both generators operate at high load ranges (>55-60 MW) and rough zone operation when both or one unit operates below ~50 MW.

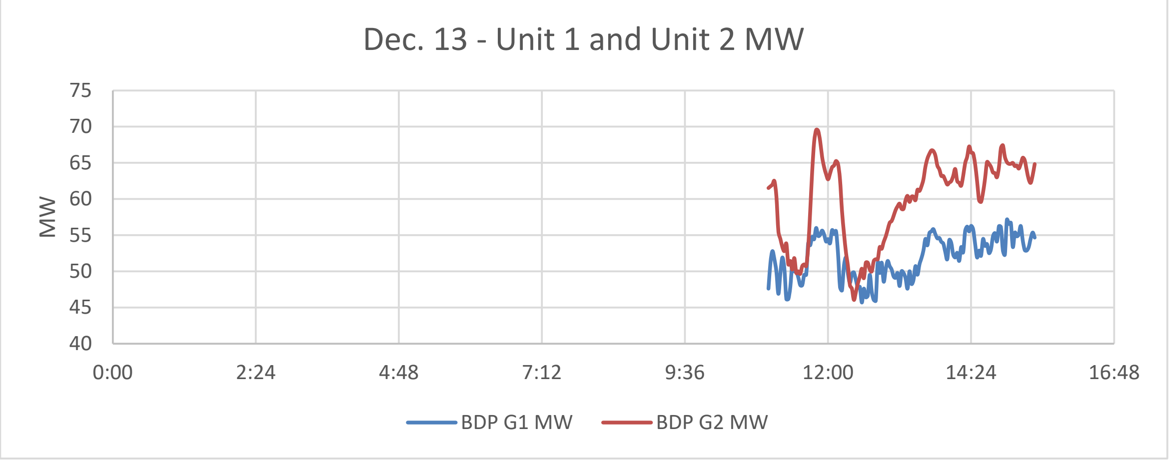


Figure A-32: Dec. 13 Unit 1 and Unit 2 MW

Table A-14 contains the averages, maximums, and minimums for 1000s (~11:48-12:04) of one of the smoothest sections from Dec. 13. From Table A-13 and Table A-9, the values are not quite comparable as Unit 1 operation for the selected dataset on Dec. 13 is approximately 54-56 MW versus Unit 1 operation (out of rough zone) for Dec. 8 is approximately 70 MW. As Dec. 13 is at a lower operating point, the flow will be lower and the dynamic head will be higher, as shown by the higher average T33 pressure (Table A-13). Average stresses should also be slightly higher for Dec. 13, which is shown for T33_INT_P00_PS1. T65_INT_P105_PS1 has a similar average value to that of Dec. 8. For the maximum and minimum values, Dec. 13 shows a greater differential, of approximately twice the differential of the Table A-9 values. A 20s frequency analysis shows prominent 0.4, ~1.0, and ~2.0 Hz frequencies. As this zone is on the borderline between smooth and rough operation the rough frequencies are becoming noticeable. The spectral amplitude of the ~1.0 Hz frequency is only ~0.094 psi (Table A-16 and Figure A-33) for the 20s analyzed which is minimal compared to the rough zone ~1.0 Hz frequency for the 2 unit operation as shown in Table A-13. The rough zone spectral amplitude of the smoothest section of Dec. 13th operation is 10x that of the 2 unit ~70 MW operation. When a unit goes below ~55 MW, it starts showing the ~1.0 Hz frequency much more prominently.

Table A-13: T33 Pressure – Spectral Amplitude Comparison

T33 Pressure Frequency Comparison	Spectral Amplitude of ~1 Hz Frequency (psi)
Dec. 8, 15:07 [6180-6200s] - 2 Unit Rough Zone	0.70419691
Dec. 8, 15:07 [6970-6990s] - 2 Units ~70 MW	0.012041834
Dec. 13, 11:23 [1630-1650s]	0.09378687

Unit 1 and Unit 2 shows rough zone operation during three time periods of the Dec. 13 data. Between ~11:00 – 11:40, ~12:10 – 12:50, and ~13:10 – 13:30 the units have the ~1.0 Hz frequency occurring at a noticeable spectral amplitude. As discussed at the end of section 3.3.5, Unit 2 showed small spectral amplitude rough zone operation up until passing through ~53 MW as it ramped up to ~70MW on Dec. 8. Table A-15 shows the average, max, and min values of an ~18 minute section (~12:30-12:48) where the Unit 1 is below 50 MW.

A frequency analysis was performed on the T33 Pressure for the first rough zone (11:00 – 11:40) in Figure A-36. The ~1 Hz frequency is present with a magnitude of ~0.31 psi. Analyzing the next section (12:10 to 12:50), a 20s plot with U1 and U2 each at 47-48 MW produced the frequency plot in Figure A-37 with the ~1 Hz frequency at 0.95 Hz and a magnitude of 0.34 psi. These frequency magnitudes are approximately half the magnitude of the Dec. 8 2 unit rough zone.

Table A-14: T33 Pressure, T65_INT_P105_PS1, & T33_INT_P00_PS1 for Dec 13, 11:23 [1500-2500s]

Dec. 13, 11:23 [1500-2500s]			
	T33 Pressure (PSI)	T65_INT_P105_PS1 (MPa)	T33_INT_P00_PS1 (MPa)
Average	36.44	269.4	144.04
Max	37.18	271.91	145.36
Min	35.86	266.24	142.67

Table A-15: T33 Pressure, T65_INT_P105_PS1, & T33_INT_P00_PS1 for Dec 13, 12:23 [400-1500s]

Dec. 13, 14:23 [400-1500s]			
	T33 Pressure (PSI)	T65_INT_P105_PS1 (MPa)	T33_INT_P00_PS1 (MPa)
Average	37.06	271.32	146.06
Max	38.09	279.77	148.44
Min	36.03	262.81	143.49

Table A-16: T33 Pressure Frequencies – Dec. 8 vs. Dec. 13 (20s)

T33 Pressure - Frequency			
Dec. 8, 15:07 [6970 - 6990s]		Dec. 13, 11:23 [1630-1650s]	
Frequency (Hz)	Spectral Amplitude (PSI)	Frequency (Hz)	Spectral Amplitude (PSI)
0.4	0.075912927	0.25	0.016467561
0.45	0.038642885	0.3	0.015668734
0.5	0.026539181	0.35	0.020671255
1.9	0.025485501	0.4	0.067731598
0.7	0.023707081	0.45	0.059077378
0.35	0.02344908	0.5	0.018180798
3.05	0.016741819	0.6	0.022238063
0.75	0.015787861	0.65	0.019895616
1.85	0.015735313	0.7	0.016495934
0.85	0.015581806	0.75	0.018390044
1.6	0.015550114	0.9	0.047214582
0.8	0.015038223	0.95	0.09378687
1.7	0.013222011	1	0.017065677
0.55	0.013018671	1.05	0.016791676
2.9	0.012113623	1.3	0.024339736
0.95	0.012041834	1.6	0.042428789
1.55	0.011902587	1.65	0.015696534
0.65	0.011520902	1.75	0.015725144
1.65	0.011343933	1.8	0.01952806
2.85	0.011329448	1.85	0.060166238
0.9	0.011088838	1.9	0.090447907
2.8	0.01096312	1.95	0.029229314
1.75	0.010581412	2	0.039309874
4.35	0.010237795	2.15	0.021723973
3	0.010050805	2.2	0.015476356
		2.8	0.018579382
		2.9	0.021171611

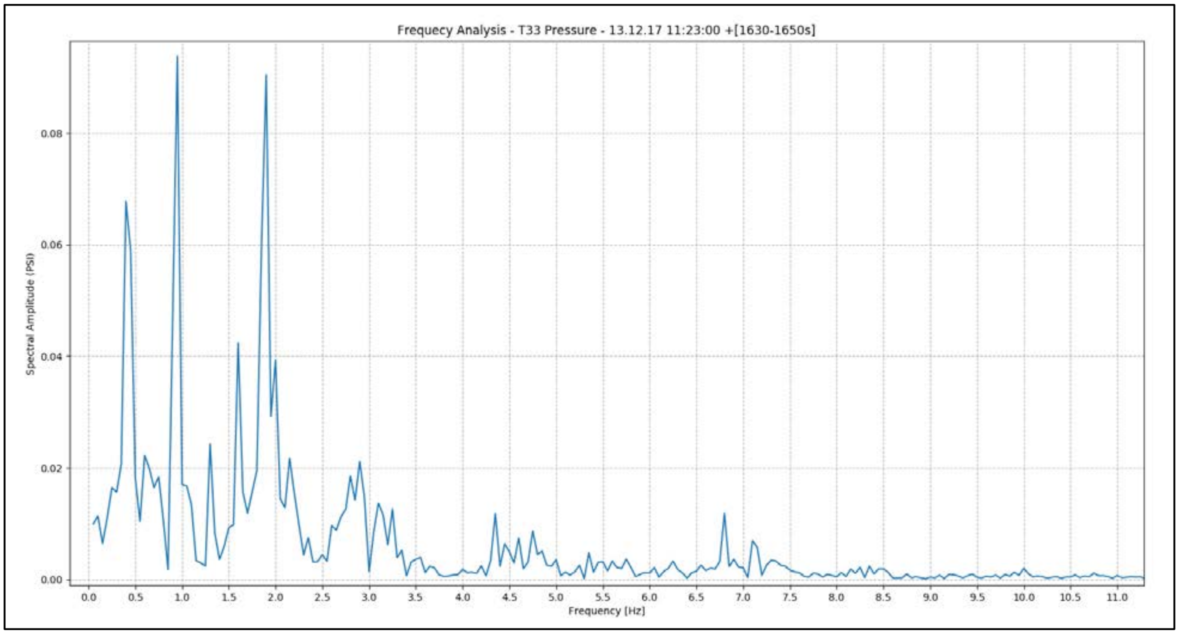


Figure A-33: Frequency Analysis – T33 Pressure – Dec. 13 (20s)

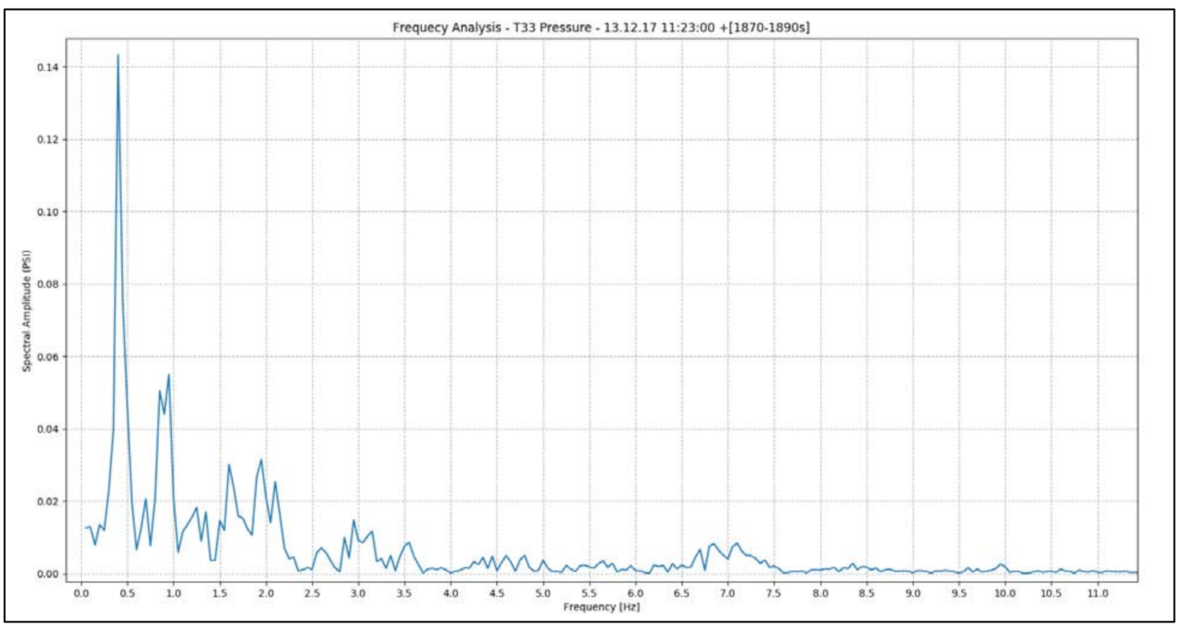


Figure A-34: Frequency Analysis – T33 Pressure – Dec. 13 (20s)

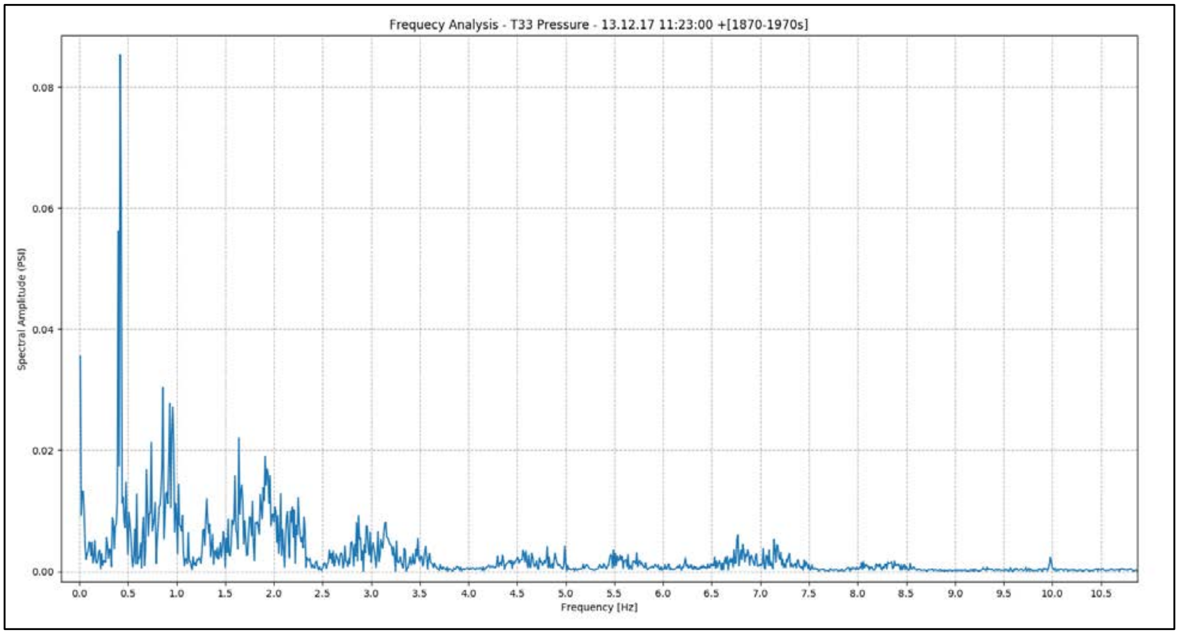


Figure A-35: Frequency Analysis – T33 Pressure – Dec. 13 (100s)

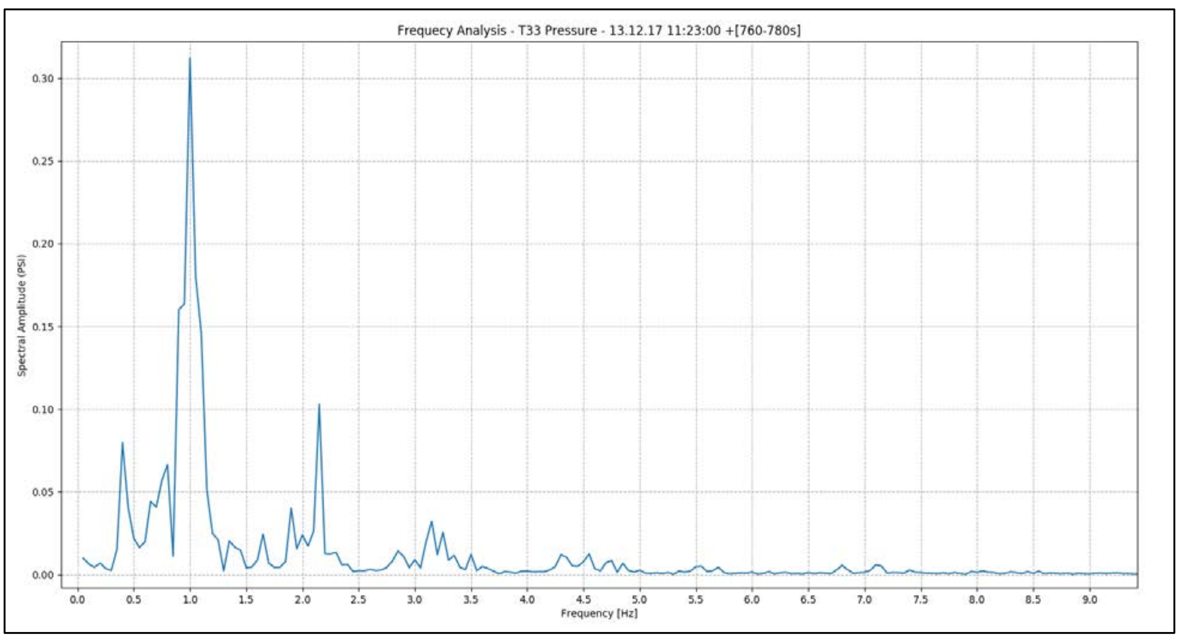


Figure A-36: Frequency Analysis – T33 Pressure – Dec. 13 (20s)

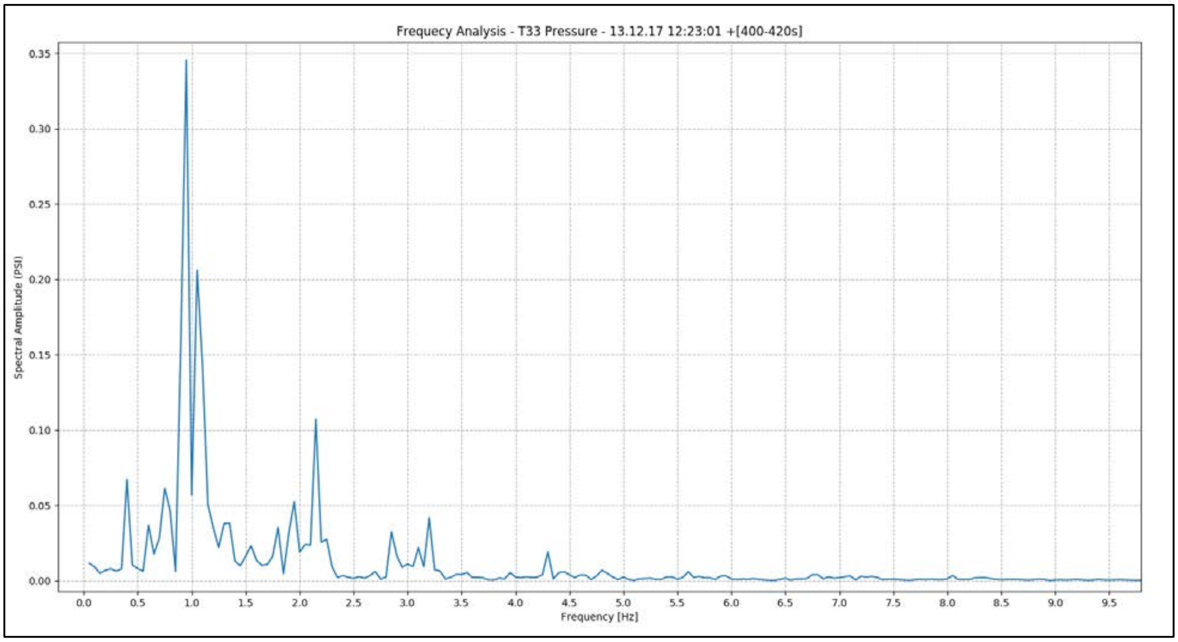


Figure A-37: Frequency Analysis – T33 Pressure – Dec. 13 (20s)

A.4.3 December 24

The operational state on Dec. 24th had much rough zone operation throughout the day. Hatch received 4 hours of SG logger data from Dec. 24th in rough zone operation. This data compared very well against the data collected on Dec. 8th for rough zone operation. The generators for the Dec. 24th data had an average of 43.55 MW for Unit 1 and 42.59 MW for Unit 2. The dataset ranges from Dec. 24, 12:00 – 15:59. As shown in Figure A-38, on 4 occasions, both Unit 1 and Unit 2 MW dropped to 20-25 MW, increasing the rough zone magnitude.

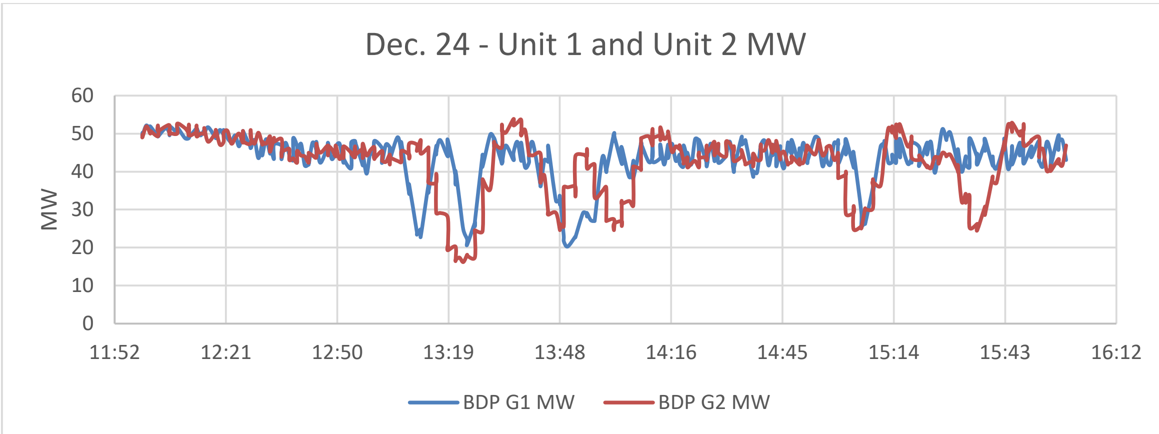


Figure A-38: Dec 24 – Unit 1 and Unit 2 MW

On Dec. 24th, Hatch identified 13:27:33 – 14:27:34 for comparison to the Dec. 8th two unit rough zone.

Comparing the average, minimum, and maximum values of Table A-17 with Table A-7 of Dec. 8, the average pressure at T33 is very similar (~0.42 psi difference). The unit loads on Dec. 8 for the rough zone were ~29 MW (unit 2, unit 1 was noted to be similar during the testing on Dec. 8, though no data was given for unit 1 from the Plant Logger) versus the average 43.55 MW and 42.59 MW for unit 1 and 2 on Dec. 24. Due to the load differences on the two dates, there will be a slight pressure variation caused by the dynamic head and differing flow rates. The head pond level will be different for the two dates as the average pressure is quite similar for both dates while they are at different operating loads. As Dec. 24 is, on average, operating at a higher load, the dynamic head should be slightly lower, and resulting lower pressure should produce lower average stress levels, as shown in Table A-17. Considering the maximum and minimum values, Dec. 24 shows a greater differential in amplitude between the average and max/min values.

From the Fourier Analysis, for a period of 20s, the most prominent frequencies are 0.4, 1.0, 2.0, 3.0, and 3.10 Hz. As shown in Table A-18, both Dec. 8 and Dec. 24 have very similar frequencies. The frequency magnitudes are also similar, but Dec. 24 is slightly higher, with the ~1.0 Hz "rough frequency" having a magnitude of ~1.03 vs ~0.70 psi on Dec. 8. The rough frequency having a larger magnitude is likely due to the variation in unit MW, whereas on Dec. 8 the 2 unit rough zone was held at a more constant load for the test. Due to the higher frequency magnitudes on Dec. 24, the maximum and minimum values are noted to have a greater differential from the average value as shown when comparing Table A-17 and Table A-7.

Further analysis of 20s rough zone sections on Dec. 24 produced some 1.0 Hz frequencies with magnitudes as high as ~1.26 psi as shown in Figure A-40.

Table A-17: T33 Pressure, T65_INT_P105_PS1, & T33_INT_P00_PS1 for Jan. 11, 13:27 [0-3600s]

Dec. 24, 13:27:33 [0-3600s]			
	T33 Pressure (PSI)	**T65_INT_P105_PS1 (MPa)**	**T33_INT_P00_PS1 (MPa)**
Average	37.12	270.19	130.14
Max	39.38	284.96	135.53
Min	34.90	254.02	126.19

Table A-18: T33 Pressure Frequencies – Dec. 8 vs. Dec. 24 (20s)

T33 Pressure - Frequency			
Dec. 8, 15:07 [6180 - 6200s]		**Dec. 24, 14:23 [1000-1020s]**	
Frequency (Hz)	**Magnitude (PSI)**	**Frequency (Hz)**	**Magnitude (PSI)**
0.05	0.034874136	0.05	0.036340384
0.4	0.079282283	0.35	0.03862636
0.45	0.043840547	0.4	0.115627789
0.7	0.076458611	0.45	0.042660683
0.85	0.130661986	0.7	0.030629046
0.9	0.172735508	0.75	0.038962644
0.95	0.102447889	0.95	0.101839221
1	0.70419691	1	1.026391937
1.05	0.035349983	1.05	0.037539963
1.3	0.100395667	1.4	0.036585616
1.85	0.034828596	1.6	0.038310121
1.9	0.055162902	1.65	0.038011818
1.95	0.058945476	1.7	0.034342703
2	0.179936059	1.75	0.03938218
2.1	0.079249447	1.8	0.037846369
2.65	0.045209317	1.9	0.052700432
2.8	0.035964297	1.95	0.042637398
2.9	0.052633442	2	0.283019066
3	0.039251309	2.05	0.044993932
3.05	0.036311774	2.1	0.041528007
3.45	0.030606117	2.2	0.038718696
		2.25	0.042930791
		2.95	0.038559036
		3	0.042997026
		3.1	0.048912061
		3.15	0.034965796

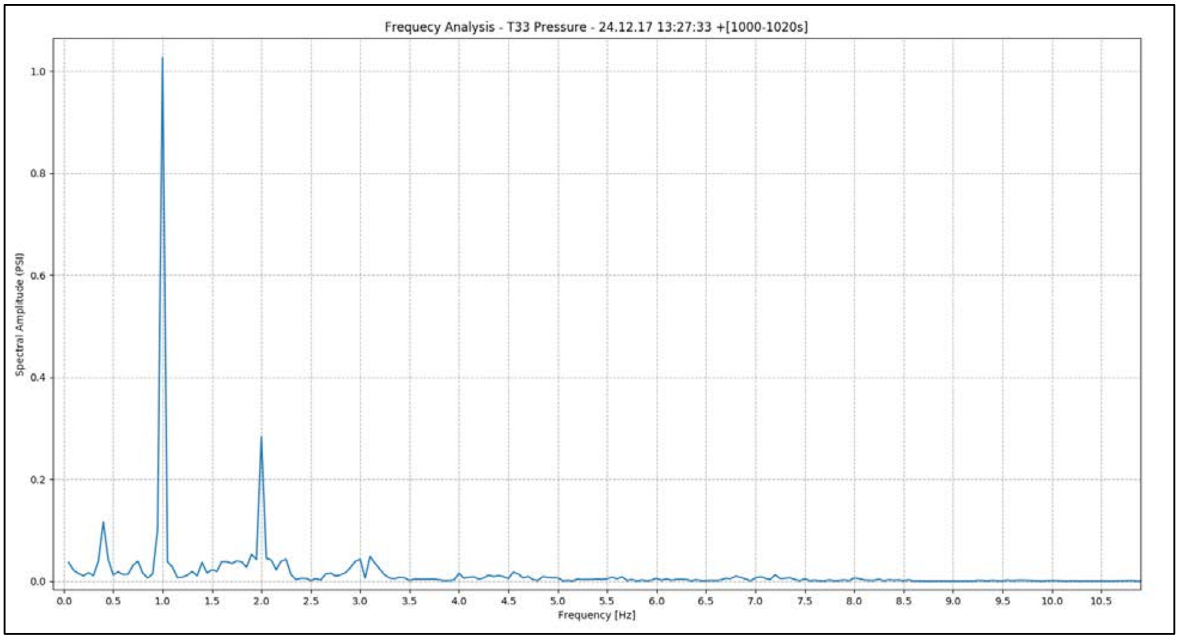


Figure A-39: Frequency Analysis – T33 Pressure – Dec. 24 (20s)

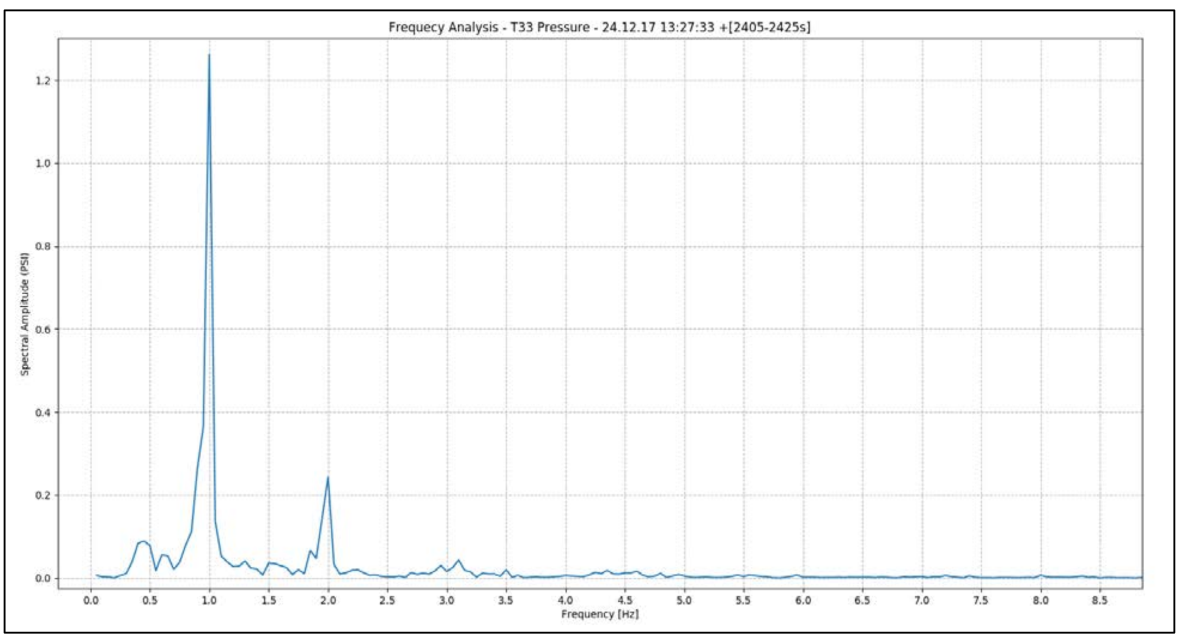


Figure A-40: Frequency Analysis – T33 Pressure – Dec. 24 (20s)

A.4.4 January 11

Hatch received approximately 6 hours of data for the day of Jan. 11th from approx. 18:10 to 12:38 on Jan 12th. Upon receiving the data, Hatch also received notification from the NRC that many of the strain gauges had become compromised or were producing very noisy readings. Almost all of the sensors for T33 – T36 remained fine (1 gauge on T33_INT_P00 was noisy, it appears water intrusion may be starting to occur) but 7 of the external rosettes on T65 were considerably noisy and 4 rosettes on the inside had become compromised. For the noisy sensors NRC opted to apply a 2 Hz Butterworth low pass filter to each strain reading for the gauge and once again to some of the calculated principal stresses.

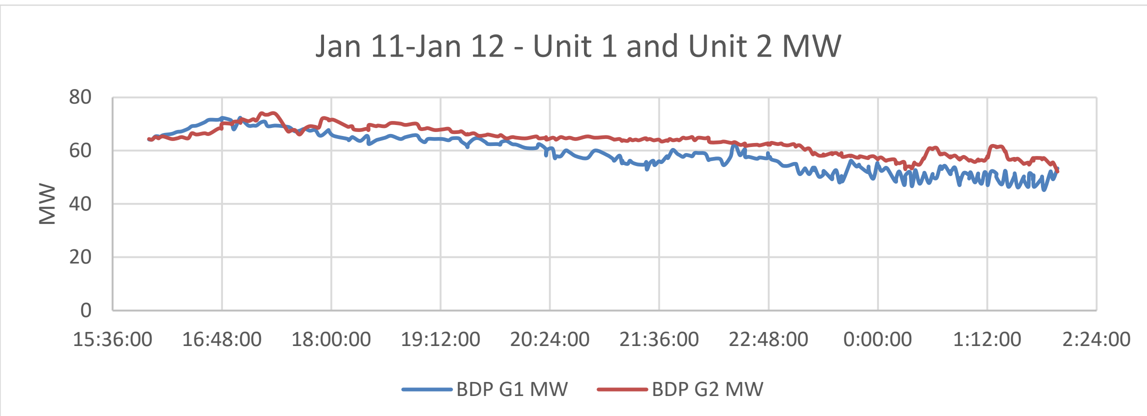


Figure A-41: Jan 11 into Jan 12 – Unit 1 and Unit 2 MW

For comparison Hatch selected an hour of data from ~18:10 – 19:10 on Jan. 11. The average MW for the generators for the 1 hour time period was 64.44 MW for Unit 1 and 68.87 MW for Unit 2. As the generator loads for this time are quite similar to the "Out of Rough Zone Operation" on Dec. 8, these datasets were compared.

The Fourier analysis was completed for a 20s time period. The prominent frequencies are shown in the table below. The notable frequencies for both Dec. 24 and Jan. 11 in "smooth operation" have very minimal magnitudes at less than 0.1 psi for a 20s sample.

Table A-19: T33 Pressure, T65_INT_P105_PS1, & T33_INT_P00_PS1 for Dec 13, 14:23 [0-3600s]

Jan. 11, 18:09:39			
	T33 Pressure (PSI) [0-3600s]	T65_INT_P105_PS1 (MPa) [0-3600s]	T33_INT_P00_PS1 (MPa) [2800-3400s]
Average	34.01	256.54	126.18
Max	34.41	258.34	127.19
Min	33.71	254.99	124.38

Note: T33_INT_P00_PS1 showed areas with high noise, therefore the values in Table A-14 were selected from a time where the noise was considerably less.

Comparing the average, minimum, and maximum values to the Dec. 8 operation (out of rough zone), unit 1 is operating at a lower load and unit 2 is operating at a load of 68.87 MW (Unit 2 on Dec. 8, out of rough zone averaged 68.17 MW). As unit 2 operation at both times has very little difference in load, due to the difference in Unit 1 operation (64.44 MW vs. ~70 MW), the dynamic head should result in a higher dynamic pressure for Jan. 11th. Dec. 8th shows a higher average pressure (by ~1.62 psi) which is accounted to the difference in head pond level as these two dates are over a month apart.

Stresses listed in Table A-19 and Table A-9 also compare similarly, but as the Jan. 11 pressure is lower, as are the T65 and T33 stresses.

Comparing the frequencies and magnitudes for T33 pressure (20s), both dates have similar frequencies with the highest magnitude frequency being 0.4 Hz at magnitudes that are almost the same (0.05 vs 0.06 psi). Referring to figure A-42, the T33 transducer shows some 5hz and 10hz frequencies as well.

Table A-20: T33 Pressure Frequencies – Dec. 8 vs. Jan. 11 (20s)

T33 Pressure - Frequency			
Dec. 8, 15:07 [6970 - 6990s]		Jan. 11, 18:09 [1600-1620s]	
Frequency	Mag	Frequency	Mag
0.35	0.02166592	0.05	0.012021939
0.4	0.05123107	0.35	0.012094258
0.45	0.037552056	0.4	0.064029325
0.5	0.022304435	0.45	0.045451231
0.8	0.040133842	0.5	0.014456511
0.95	0.04064298	0.55	0.017627128
1	0.020792679	0.7	0.014165693
1.65	0.02249319	0.75	0.011983115
1.8	0.020083902	1.6	0.013338118
1.9	0.02363067	1.95	0.013731484
3.05	0.022879279	3.2	0.013833408
3.2	0.021650776	5	0.018047984

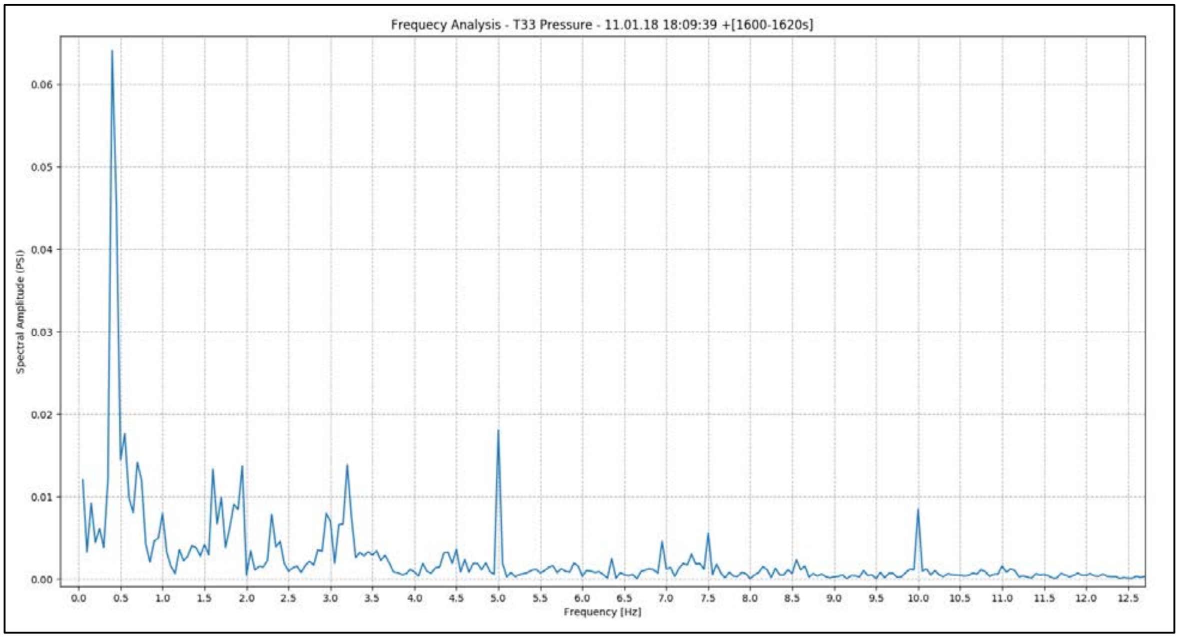


Figure A-**42: Frequency Analysis – T33 Pressure – Jan. 11 (20s)**

Appendix B
Finite Element Modeling Results

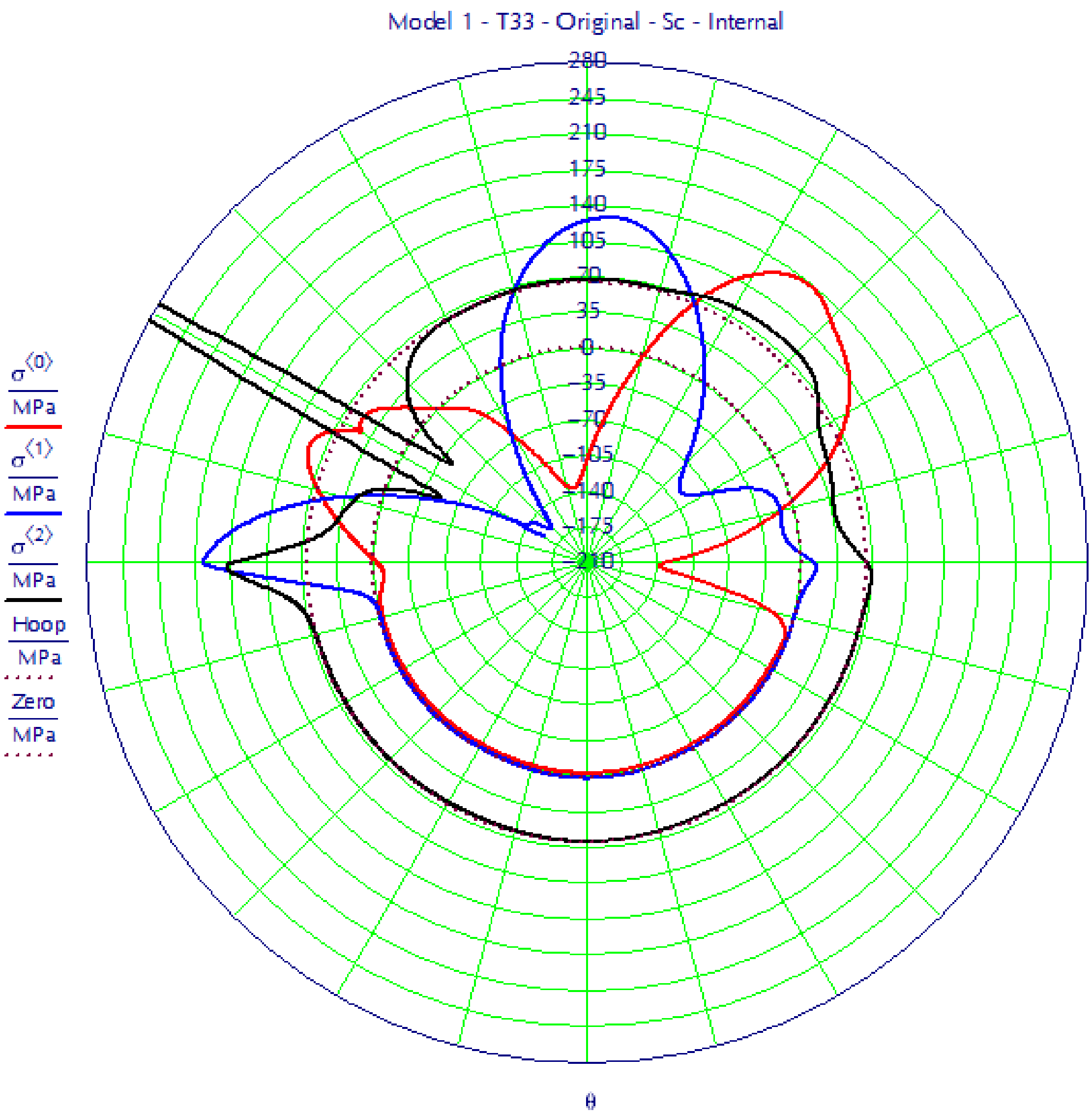


Figure B-1: Circumferential Stresses (As-built Backfill) Stress Distribution on the Inside

Legend: 0=empty penstock (soil + steel weight); 1=filled with water (soil + steel + water weight) 2= pressurized (soil + steel +water weight + 38.21 psi internal pressure)

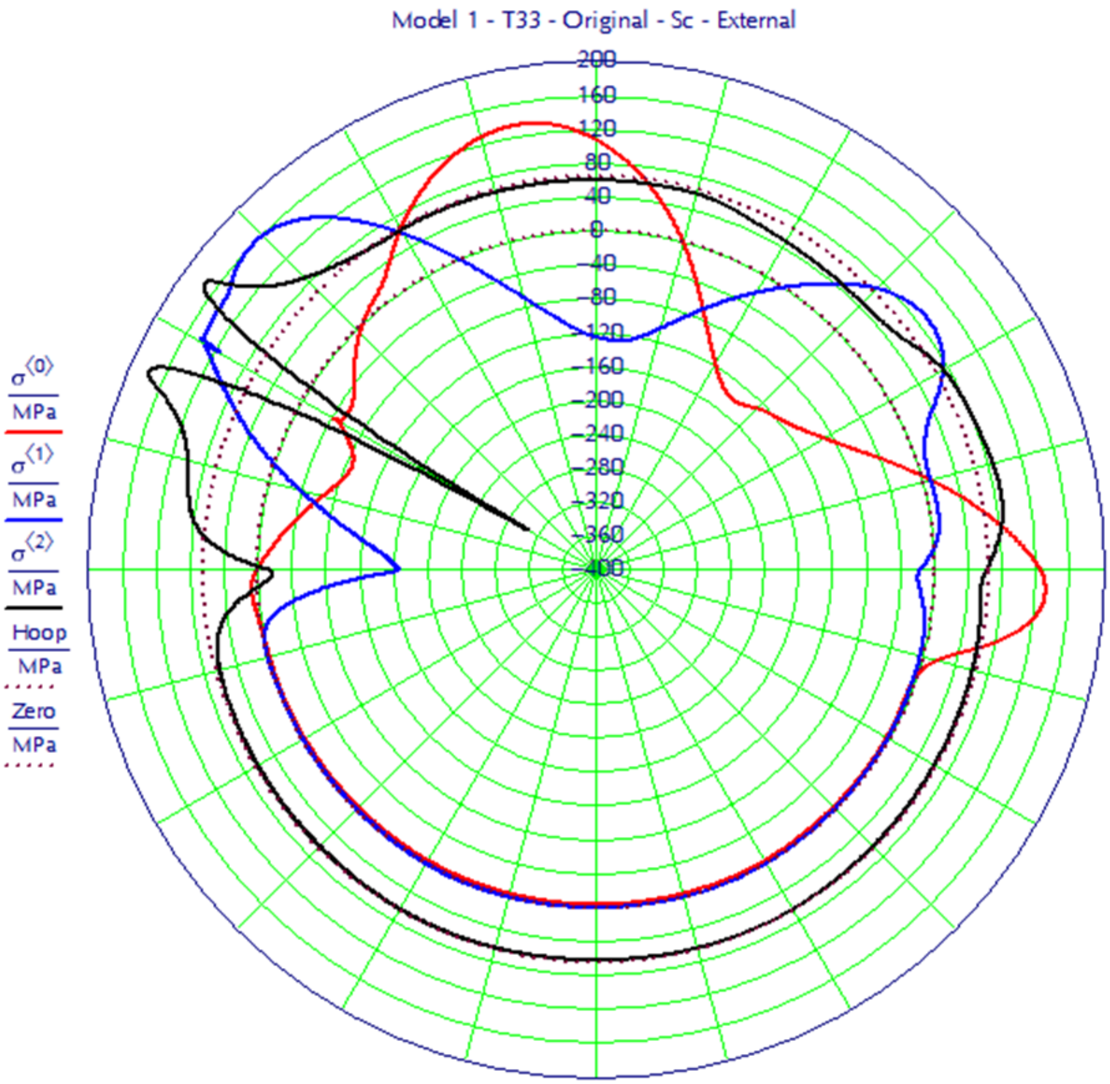


Figure B-2: Circumferential Stresses (As-built Backfill) Stress Distribution on the Outside

Legend: 0=empty penstock (soil + steel weight); 1=filled with water (soil + steel + water weight) 2= pressurized (soil + steel +water weight + 38.21 psi internal pressure

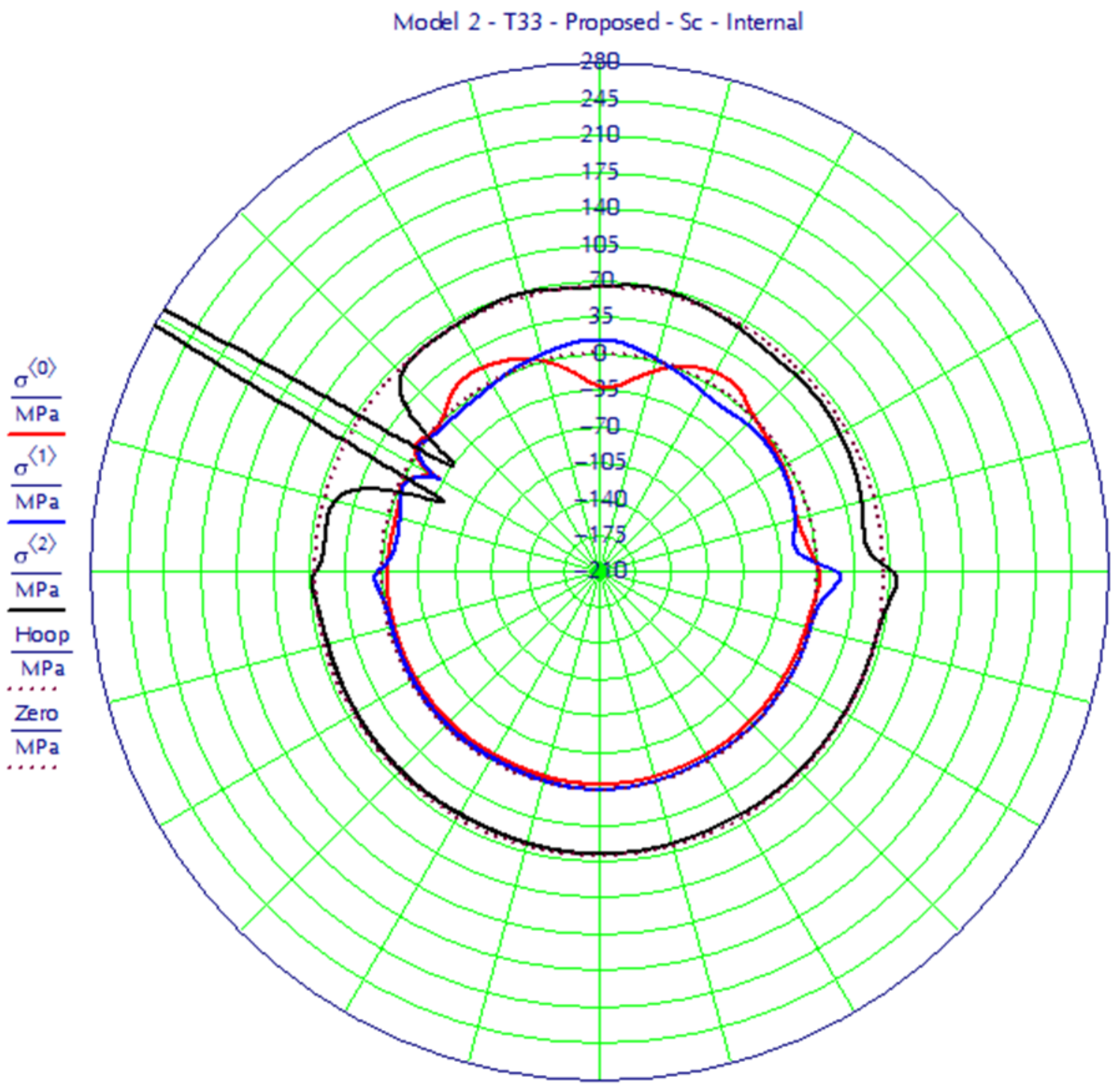


Figure B-3: Circumferential Stresses (Additional Backfill by Hatch) Stress Distribution on the Inside

Legend: 0=empty penstock (soil + steel weight); 1=filled with water (soil + steel + water weight) 2= pressurized (soil + steel +water weight + 38.21 psi internal pressure

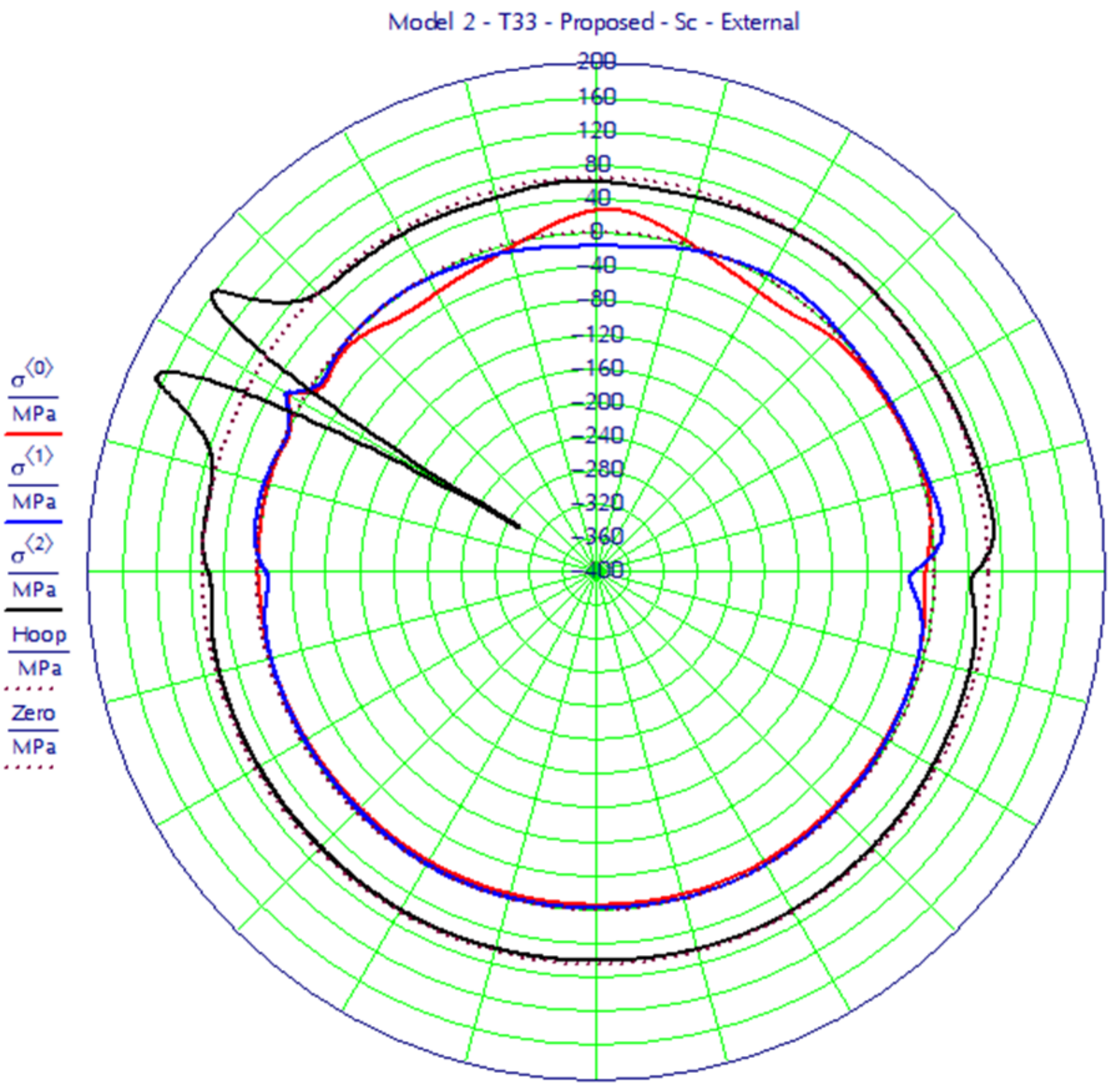


Figure B-4: Circumferential Stresses (Additional Backfill by Hatch) Stress Distribution on the Outside

Legend: 0=empty penstock (soil + steel weight); 1=filled with water (soil + steel + water weight) 2= pressurized (soil + steel +water weight + 38.21 psi internal pressure

Appendix C
Test Results

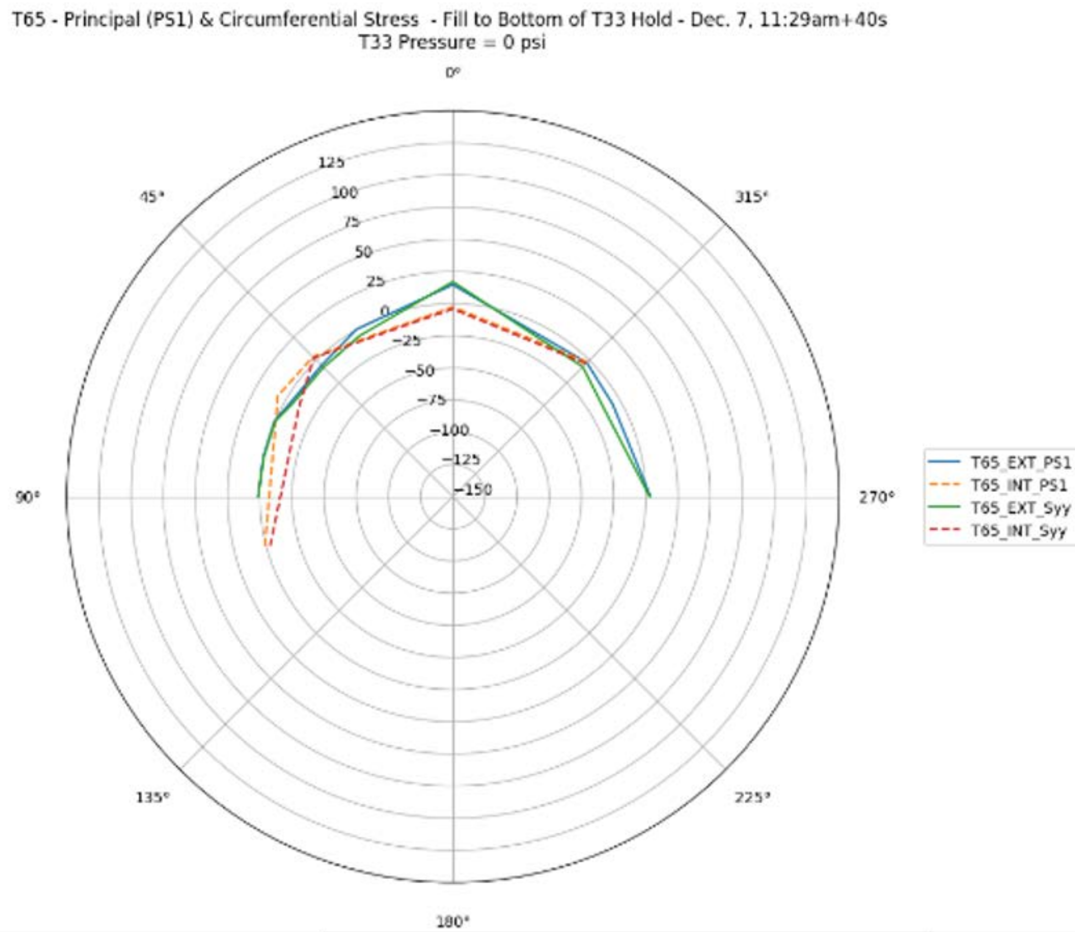


Figure C-1: Measured Stresses(MPa) at T65 with Water to the Top of Penstock Section

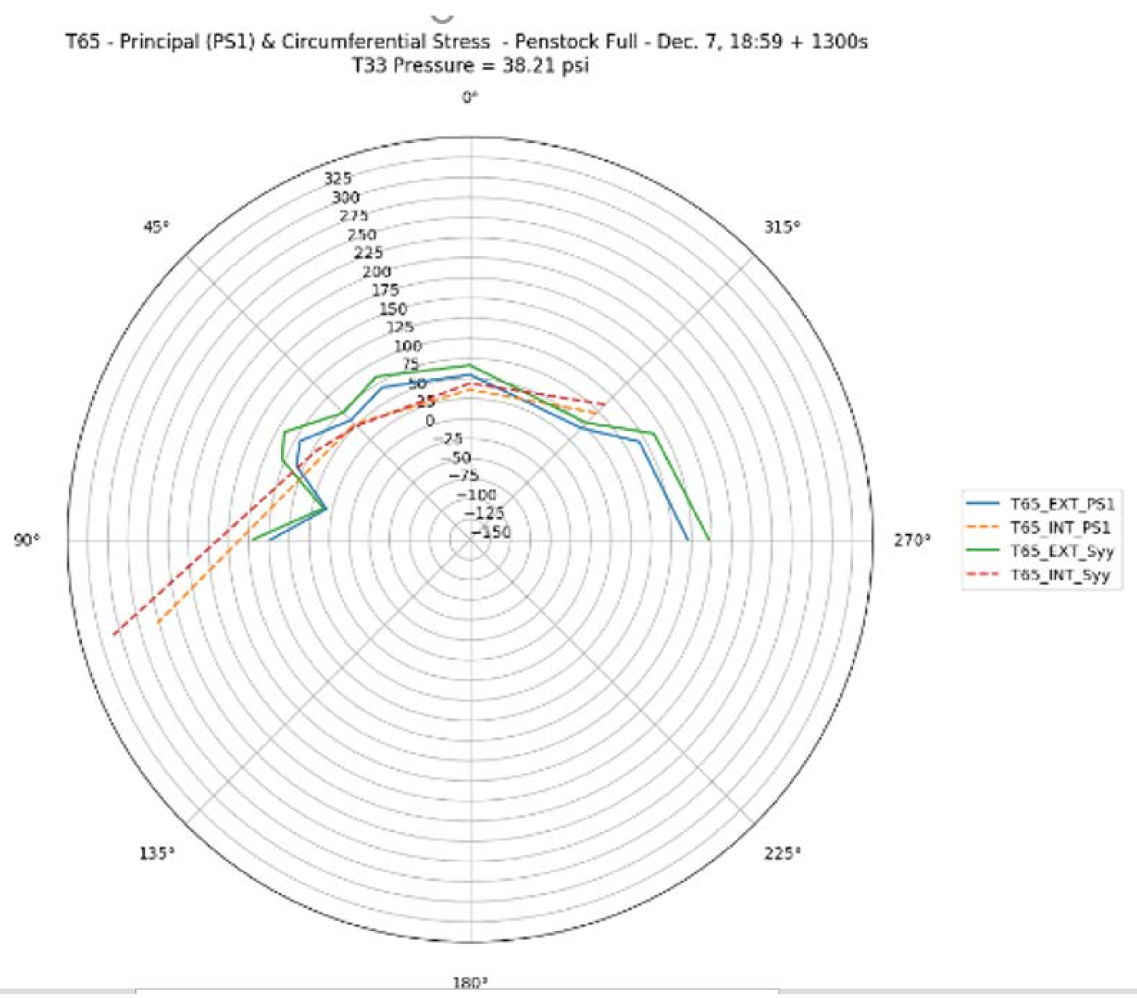


Figure C-2: Measured Stresses (MPa) at T65 with Penstock Full

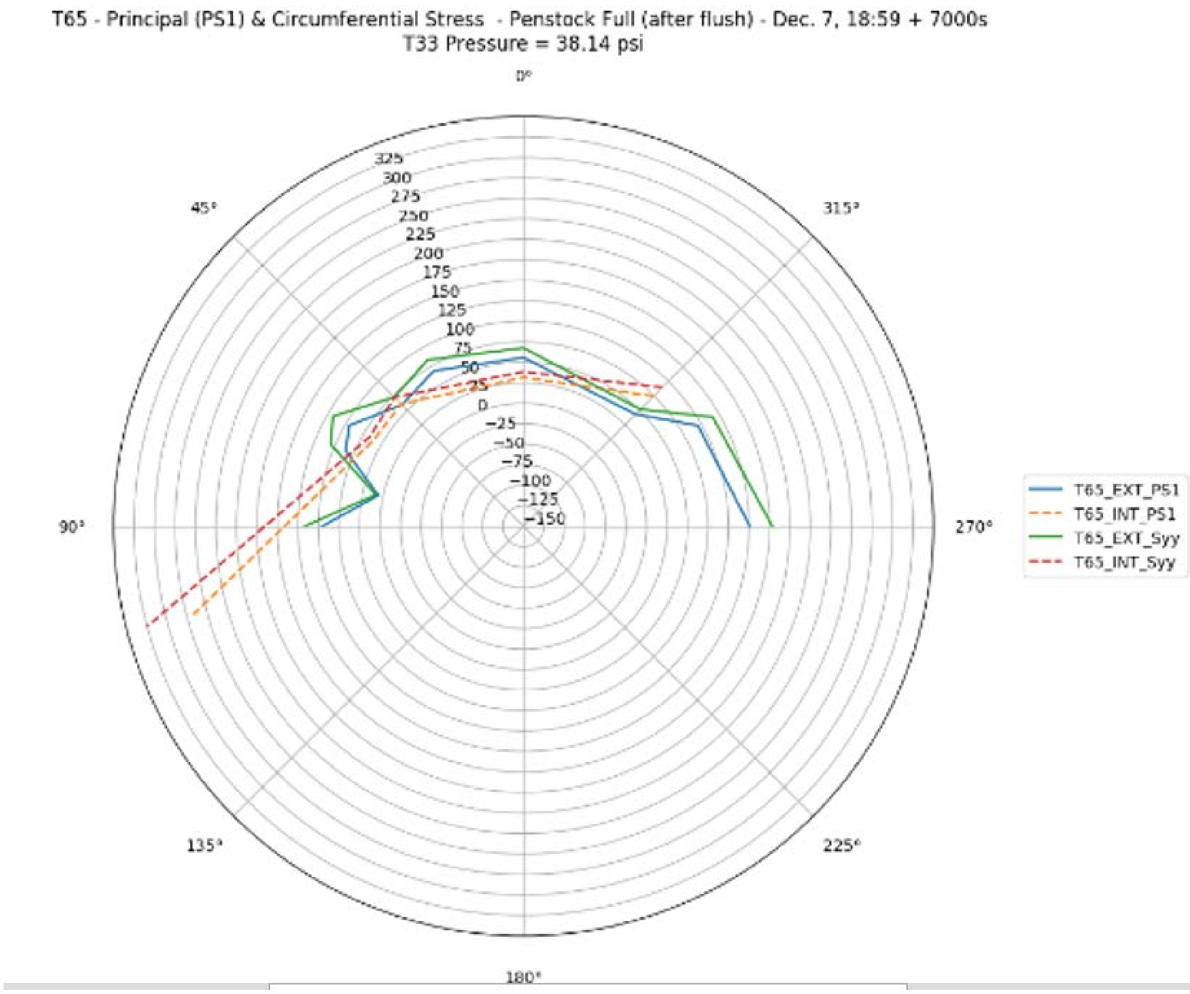


Figure C-3: Measured Stresses (MPa) at T65 After Unit Flush

Appendix D
Fatigue Analysis

D.1 Introduction

Stemming from the BDE Penstock No. 1 repair and root cause analysis, Hatch determined the effect of Fatigue resulting from the “Rough Zone” produced during certain load operating ranges for Units No. 1 and No. 2 at the Bay D’espoir (BDE) Hydroelectric Generating Facilty. The rough zone produces a vibration or pulsation that travels up the penstock resulting in a pressure/stress cyclical variation.

Various penstock/unit operations can also contribute to the fatigue of the penstock and were broken down into the following zones for analysis:

Table D-1: Operational Zones Analyzed

Operational Zones Analyzed	
Zone 1	Spherical Valve Opening
Zone 2	2 Unit Rough Zone
Zone 3	1 Unit Rough Zone
Zone 4	Spherical Valve Closing
Zone 5	Load Rejection
Zone 6	Wicket Gate Opening on Startup
Zone 7	Wicket Gate Closing
Zone 8	Normal operation
Zone 9	Penstock De-water and water up

Fatigue assessment of welds was chosen as the past recent failures have all been in the toe of a longitudinal weld seam. The cans also have stress concentrations due to the geometry “peaking” (from construction) at these seams and the stress concentration and environmental factors increasing failure likelihood at the toe of the weld.

D.2 Fatigue Assessment

D.2.1 Method

The fatigue assessment was completed to ASME BPVC VIII.2, Section 3-F.2.2 and 5.5.5. Using the procedure outlined in the noted sections, the allowable design cycles, N, was calculated for each zone identified in Section 1.0 and compared with the estimated actual number of repetitions, n. A fatigue damage factor was then calculated and summed across all zones to determine the total fatigue damage on Penstock No. 1. The sum of the damage factor, D, across all zones must be less than 1.0.

Strains from gauge T65_INT_P105 were used to calculate the stresses as it was the gauge that was closest to a longitudinal weld seam. A stress concentration factor was then applied to approximate the stress, due to the “peaking”, in the weld seam. The resulting stress ranges were used to determine the allowable design cycles.

Equation 3-F.22 (allowable design cycles, N), ASME BPVC VIII.2, uses an environmental modification factor that accounts for the fluid environment, loading frequency, temperature, and material variables. ASME VIII does not provide guidelines on the environmental factor therefore, analysis was completed using an environmental factor of 1.0 (no effect) and environmental effects are later discussed in Section D.2.5.

D.2.1.1 Bulge Stress Concentration

Referring to Figure 7-3, a FE model was produced to determine the stress concentration or multiplication factor produced from the peaking/bulge. Using a conservative bulge distance, b = 25 mm, produces a multiplication factor of approximately 1.42 (distance from bulge center, d = ~16mm, as the nearest strain gauge, T65_INT_P105, was approximately 5mm off of the toe of the weld).

D.2.2 Zone Cycles

The number of cycles for reach zone described in section one was evaluated from the following table:

Table D-2: Life Cycles

Number of Years in Service	50
Average no. of **starts/stops** per year	365
Life-time starts+ Stops	18250
Load Rejections per year	2
Life-time Load Rejections	100

NL Hydro provided Hatch with operational data from 2013-2017 for Unit 1 and Unit 2 MW ranges. Using this data, Hatch tabulated the rough zone hours across these years based on 25-40 MW operation (this operational range was determined to produce the most significant vibrations from the data analyzed from the Strain Gauge Logger and Plant Logger from Dec. 2017 – Jan. 2018).

Table D-3: Rough Zone Operation 2013 - 2017

Year	Unit #	Rough Zone Hours	2 Unit Operation	1 Unit Operation
2013	1	187.67	31.67	302
	2	177.67		
2014	1	700.33	96.67	688.66
	2	181.67		
2015	1	275.67	38.67	486.66
	2	288.33		
2016	1	441	124.33	465.34
	2	273		
2017	1	319.33	36.33	347.34
	2	100.67		
SUM			327.67	2290

D.2.3 Zone Data

D.2.3.1 Spherical Valve Opening

Data for the spherical valve opening was captured on the morning of Dec. 8 prior to the Unit 2 flush and also Dec. 8 PM prior to the testing of 2 unit rough zone operation.

Table 2-3 shows the fatigue assessment for the spherical valve opening. This table uses an average cycle stress range as the valve opening causes a spike in pressure followed by an oscillation that attenuates. The oscillation occurs for approximately 300s upon opening with a frequency of approximately 0.4 Hz, which was applied to the lifetime start stop value identified in Table 2-2. As the operation of the penstock in recent years does not always result in shutdown overnight (or each day), this method is conservative but still produces a very small fatigue damage factor.

Table D-4: Spherical Valve Opening Fatigue Assessment Summary

Zone 1 - Spherical Valve Opening Dec. 8 morning flush - 9:15:08, t = 0)		
T33 Pressure	Peak (PSI)	Valley (PSI)
	38.52	37.995
T65_INT_P105_PS1	Peak (MPa)	Valley (MPa)
	277.42	275.575
Frequency		~0.4 Hz
N, (allowable design cycles)		8.23E+08
n, (actual number of cycles)		2.04E+06
D, (fatigue damage factor)		0.002474505

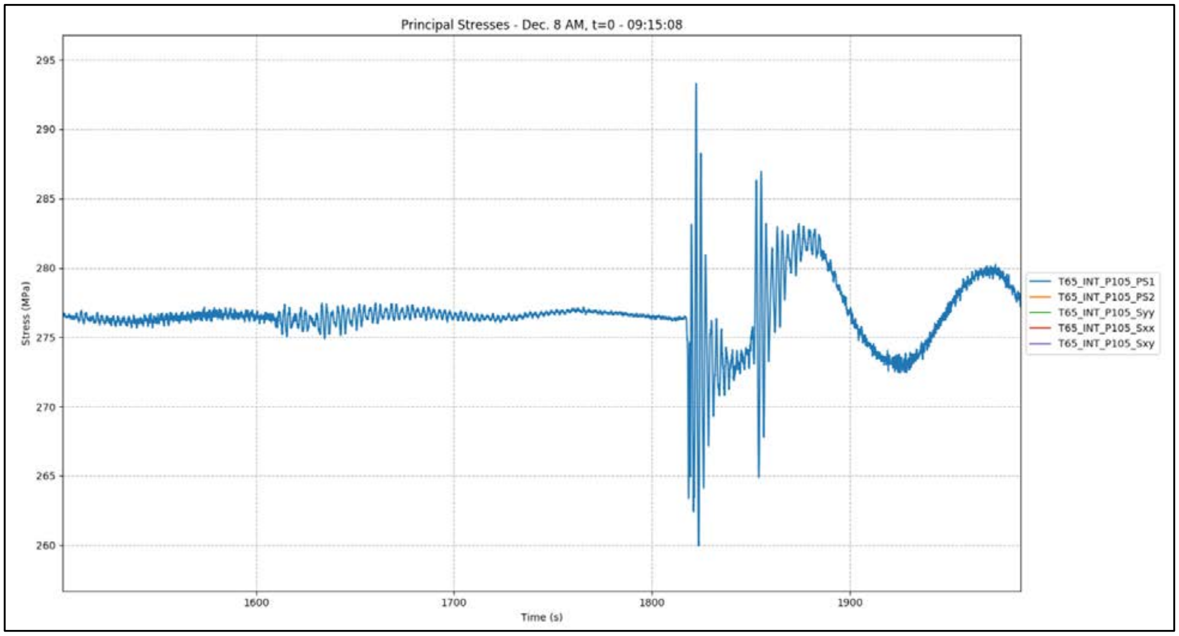


Figure D-1: Dec. 8 AM – T65_INT_P105_PS1 - Spherical Valve Opening, Wicket Gates Opening & Wicket Gates "Throttle" Closure

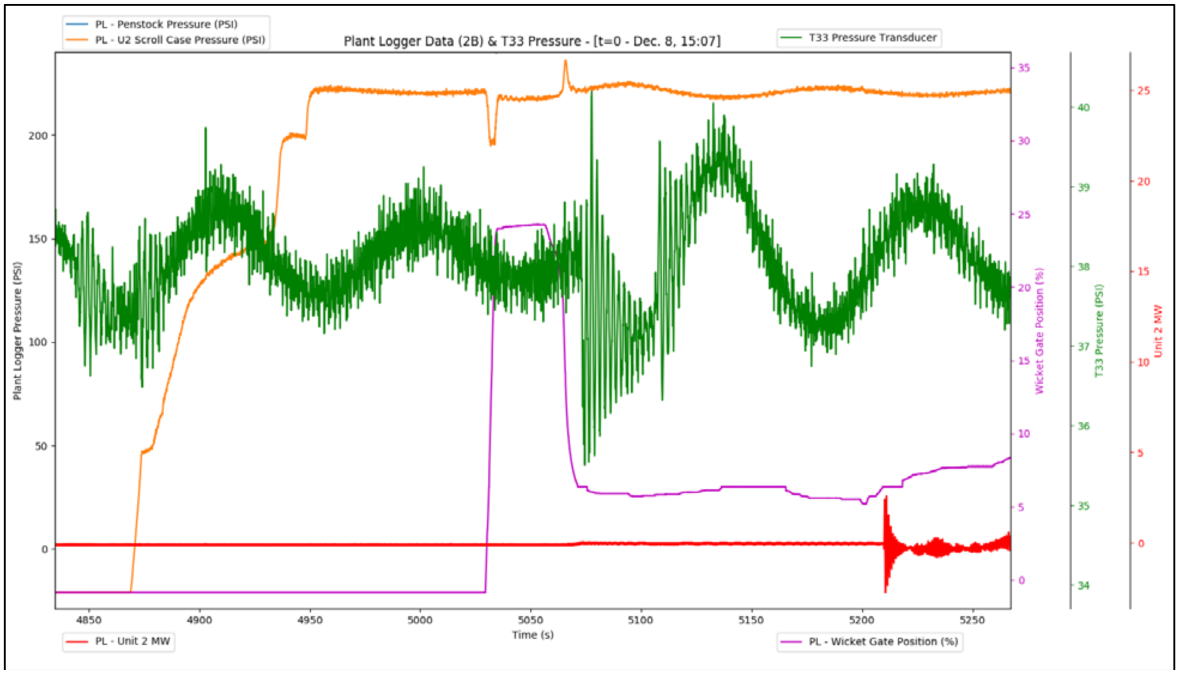


Figure D-2: Dec. 8 PM – Spherical Valve Opening & Wicket Gates

D.2.3.2 2 Unit Rough Zone

Data for the 2 unit rough zone was used from Dec. 8th. As the rough zone has a variance in the stress amplitude of roughness, an average was taken and applied across the cycles from 2013-2017. It should be noted, the rough zone intensity can vary. As the units were kept at a more constant load for the unit testing on Dec. 8, the upper limit of rough zone stress ranges is less than that of the rough zones from Dec. 24. Due to the varying loads, the intensity of the rough zone can reach a higher stress range but will also be lower at times.

Table D-5: 2 Unit Rough Zone Fatigue Assessment Summary

Zone 2 - 2 Unit Rough Zone - Dec. 8		
T33 Pressure	Peak (PSI)	Valley (PSI)
	38.33333333	36.77333333
T65_INT_P105_PS1	Peak (MPa)	Valley (MPa)
	286.36	270.97
Frequency		~1.0 Hz
N, (allowable design cycles)		7.34E+06
n, (actual number of cycles)		1.18E+06
D, (fatigue damage factor)		0.160643213

D.2.3.3 1 Unit Rough Zone

Similarly, to the 2 unit rough zone, as the stress amplitude varies, an average was taken and applied to the cycles from 2013-2017. The stress range is lower for the 1 unit rough zone but due to the increased number of cycles from 2013-2017, almost 7 times, the 1 unit rough zone has a much higher D value.

Table D-6: 1 Unit Rough Zone Fatigue Assessment Summary

Zone 3 - 1 Unit Rough Zone - Dec. 8		
T33 Pressure	Peak (PSI)	Valley (PSI)
	38.44	37.42333333
T65_INT_P105_PS1	Peak (MPa)	Valley (MPa)
	284.86	274.55
Frequency		~1.0 Hz
N, (allowable design cycles)		1.83E+07
n, (actual number of cycles)		8.24E+06
D, (fatigue damage factor)		0.451165436

D.2.3.4 Spherical Valve Closing

The spherical valve closing fatigue assessment was completed similarly to the spherical valve opening. An average stress range was selected and applied across all cycles due to the produced oscillation that attenuates.

Table D-7: Spherical Valve Closing Fatigue Assessment Summary

Zone 4 - Spherical Valve Closing Dec. 8 PM - Unit Testing (after load rejection)		
T33 Pressure	Peak (PSI)	Valley (PSI)
	38.57	37.93
T65_INT_P105_PS1	Peak (MPa)	Valley (MPa)
	283.83	281.38
Frequency		~0.4 Hz
N, (allowable design cycles)		4.29E+08
n, (actual number of cycles)		1.54E+06
D, (fatigue damage factor)		0.003595433

D.2.3.5 Load Rejection

The load rejection data from Dec. 8th was used for the fatigue assessment. The load rejection stress and pressure spikes attenuate quite quickly and therefore do not produce a great number of cycles throughout the penstock lifetime. The penstock pressure oscillation was averaged for a useable stress range that was applied across all cycles, producing a small fatigue damage factor.

Table D-8: Load Rejection Fatigue Assessment Summary

Zone 5 - Load Rejection Dec. 8		
T33 Pressure	Peak (PSI)	Valley (PSI)
	41.37666667	34.68333333
T65_INT_P105_PS1	Peak (MPa)	Valley (MPa)
	295.17	265.21
Frequency		~0.4 Hz
N, (allowable design cycles)		1.47E+06
n, (actual number of cycles)		3.51E+03
D, (fatigue damage factor)		0.002389379

D.2.3.6 Wicket Gate Opening

Following the spherical valve opening, data was captured showing the wicket gate opening. The action of the wicket gates opening produces a greater pressure spike than the spherical valve opening, resulting in a higher stress oscillation. The oscillation from the wicket gates occurred at approximately 0.4 Hz for ~32s. This cycle was applied across the lifetime start/stop value. The stress range used was an average from the attenuating oscillation.

Table D-9: Wicket Gates Opening Fatigue Assessment Summary

Zone 6 - Wicket Gate Open - Dec. 8 AM		
T33 Pressure	Peak (PSI)	Valley (PSI)
	39.20666667	35.58
T65_INT_P105_PS1	Peak (MPa)	Valley (MPa)
	281.24	267.70
Frequency		~0.4 Hz
N, (allowable design cycles)		9.04E+06
n, (actual number of cycles)		2.34E+05
D, (fatigue damage factor)		0.025828608

D.2.3.7 Wicket Gate Closing

During penstock start up, the wicket gates are opened to accelerate the fluid; as the unit reaches synchronous speed, the wicket gates close to accommodate the current load and work up to the desired load. With the closure of the wicket gates to control the flow, a pressure surge is produced similarly to the opening. As the only collected data with the wicket gates closing to stop the flow is the load rejection, this data was used to estimate the wicket gate full closure. The actual number of cycles was doubled for this application due to the "throttle closure" upon opening and a closure for shutdown.

Table D- 10: Wicket Gates Closing Fatigue Assessment Summary

Zone 7 - Wicket Gate Close - Dec. 8 AM		
T33 Pressure	Peak (PSI)	Valley (PSI)
	40.715	37.275
T65_INT_P105_PS1	Peak (MPa)	Valley (MPa)
	285.10	272.67
Frequency		~0.4 Hz
N, (allowable design cycles)		1.08E+07
n, (actual number of cycles)		4.67E+05
D, (fatigue damage factor)		0.043271897

D.2.3.8 Normal Operation

The penstock under normal "smooth" operation still produces a slight vibration. The data was analyzed where unit 1 and unit 2 were each at ~70 MW on Dec. 8. This zone shows multiple frequencies at low stress ranges. The ~0.4Hz frequency oscillation was most notable and was analyzed at a stress range of ~1.1 MPa. The second frequency analyzed was ~2.5 Hz, which had a lower stress range.

Table D-11: Normal Operation Fatigue Assessment Summary (~1.0 Hz)

Zone 8 - Normal Operation - Dec. 8		
T33 Pressure	Peak (PSI)	Valley (PSI)
	35.74	35.6
T65_INT_P105_PS1	Peak (MPa)	Valley (MPa)
	270.60	269.50
Frequency		~0.4 Hz
N, (allowable design cycles)		2.94E+09
n, (actual number of cycles)		6.31E+08
D, (fatigue damage factor)		0.214316553

Table D-12: Normal Operation Fatigue Assessment Summary (~2.5 Hz)

Zone 8 - Normal Operation - Dec. 8		
T33 Pressure	Peak (PSI)	Valley (PSI)
	35.63	35.57
T65_INT_P105_PS1	Peak (MPa)	Valley (MPa)
	270.02	269.57
Frequency		~2.5 Hz
N, (allowable design cycles)		2.21E+10
n, (actual number of cycles)		6.31E+08
D, (fatigue damage factor)		0.028487602

D.2.3.9 Penstock De-water and Water Up

The cycle of de-watering the penstock and watering up the penstock again produces can be considered for fatigue assessment. Due to the large differences in stress throughout the shell between no pressure and full pressure, there is a large stress range for this zone. Using the zero pressure stress (T65 water at bottom of can hold point – Dec. 7 water up) and the static watered up stress, the cycle can be compared. A value of 10 cycles was estimated for the current lifespan of the penstock.

Table D-13: Penstock De-water & Water Up Fatigue Assessment Summary

Zone 9 - De-water/Water Up		
T33 Pressure	Peak (PSI)	Valley (PSI)
	38	0
T65_INT_P105_PS1	Peak (MPa)	Valley (MPa)
	270.00	-0.50
Frequency		
N, (allowable design cycles)		1.16E+04
n, (actual number of cycles)		1.00E+01
D, (fatigue damage factor)		0.000863931

D.2.4 Total Cycles

The total cycles calculated in Section 2.3 are summed below. Note: environmental factors (i.e. corrosion) were not taken into consideration in Section 2.3. The fatigue damage factor should sum to be less than 1.0, therefore the current summation in Table 2-15 is within acceptable limits for this assessment but is quite high. Rough zone data was available for years 2013-2017, therefore the rough zone should be considered an underestimation as roughness was noted previous to 2013 but not accounted for in this assessment due to a lack of data. As previous reports have shown the penstock internal has a corrosive environment, a fatigue environmental modification factor should be applied to the assessment, see Section 2.5.

Table D-14: Total Fatigue Damage Summary

Total Cycle Fatigue Damage	
Zone	**Fatigue Damage, D**
Spherical Valve Opening	0.0025
2 Unit Rough Zone	0.1606
1 Unit Rough Zone	0.4512
Spherical Valve Closing	0.0036
Load Rejection	0.002389
Wicket Gate Opening	0.02583
Wicket Gate Closing	0.04327
Normal Operation	0.24279
Penstock De-water/Water Up	0.0009
Sum	0.933079

D.2.5 Environmental Factor

As mentioned in Section 2.1, ASME BPVC VIII.2 notes an environmental modification factor should be applied to the allowable design cycles calculation to account for fluid environment, loading frequency, temperature, and material variables. ASME BPVC VIII does not outline permissible environmental modification factors for this application.

Neglecting the environmental modification factor produces a fatigue damage, D = ~0.93. Therefore, it would take a factor of ~1.07 to reach a fatigue damage factor D = 1.00. As the internal penstock environment is known to be corrosive, a factor of 1.08 is considerably small for the application.

ASME nuclear codes make reference to the environmental factor and NUREG/CR-6815 ANL-02/39 equates F_{EN} = 1.74 for carbon steels with temperatures less than 150°C. NUREG/CR-6815 also defines a factor of 4 for “moderate or acceptable environmental effects”.

The internal environment of the penstock must be taken into account. Applying an environmental factor will cause the fatigue damage factor to go over the acceptable limit of 1.0.

D.2.6 ASME BPVC VIII.2 Fatigue Assessment of Welds Calculation

The fatigue assessment of welds starts with section 3-F.2.2. This section outlines the calculation of the design number of allowable design cycles, N.

$$N = \frac{f_I}{f_E}\left(\frac{f_{MT} \cdot C}{\Delta S_{ess,k}}\right)^{\frac{1}{h}}$$

$f_I = fatigue\ improvement\ factor\ (1.0), f_E = fatigue\ environmental\ modification\ factor$

$f_{MT} = material\ and\ temperature\ correction\ factor\ (1.0\ for\ carbon\ steel\ at\ current\ temperatures)$

$C\ \&\ h = constants, f_{MT} - temperature\ adjustment\ factor,$
$\Delta S_{ess,k} - equivalent\ structural\ stress\ range\ parameter$

The structural stress range parameter is calculated from section 5.5.5:

The elastically calculated structural stress range is calculated:

$$\Delta\sigma_k^e = \Delta\sigma_{m,k}^e + \Delta\sigma_{b,k}^e$$

Followed by the elastically calculated structural strain:

$$\Delta\varepsilon_k^e = \frac{\Delta\sigma_k^e}{E_{ya,k}}$$

The corresponding local nonlinear structural stress and strain ranges are then calculated:

$$\Delta\sigma_k \cdot \Delta\varepsilon_k = \Delta\sigma_k^e \cdot \Delta\varepsilon_k^e$$

$$\Delta\sigma_k = \left(\frac{E_{ya,k}}{1 - v^2}\right)\Delta\varepsilon_k$$

Followed by the calculation for the equivalent structural stress range parameter:

$$\Delta S_{ess,k} = \frac{\Delta\sigma_k}{t_{ess}^{\left(\frac{2 - m_{ss}}{2m_{ss}}\right)} \cdot I^{\frac{1}{m_{ss}}} \cdot f_{M,k}}$$

From the standard: $m_{ss} = 3.6, t_{ess} = 16\ mm$

$$I^{\frac{1}{m_{ss}}} = \frac{1.23 - 0.364R_{b,k} - 0.17R_{b,k}^2}{1.007 - 0.306R_{b,k} - 0.178R_{b,k}^2}$$

$$R_{b,k} = \frac{\left|\Delta\sigma_{b,k}^e\right|}{\left|\Delta\sigma_{m,k}^e\right| + \left|\Delta\sigma_{b,k}^e\right|}$$

$$R_k = \frac{\sigma_{\min,k}}{\sigma_{\max,k}}$$

$$f_{M,k} = (1 - R_k)^{\frac{1}{m_{ss}}} \qquad for \quad \sigma_{mean,k} \geq 0.5S_{y,k}, \ and \ R_k > 0, \ and \ \left|\Delta\sigma_{m,k}^e + \Delta\sigma_{b,k}^e\right| \leq 2S_{y,k}$$

$$f_{M,k} = 1.0 \qquad for \quad \sigma_{mean,k} < 0.5S_{y,k}, \ or \ R_k \leq 0, \ or \ \left|\Delta\sigma_{m,k}^e + \Delta\sigma_{b,k}^e\right| > 2S_{y,k}$$

Using the allowable number of cycles, N, and the actual number of cycles n, the fatigue damage factor is calculated:

$$D_{f,k} = \frac{n_k}{N_k}$$

Followed by the summation across all operational zones:

$$D_f = \sum_{i=1}^{M} D_{f,k} \leq 1.0$$

Appendix E
AMC Report

Investigation of Failure of Welded Penstock

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Report No. 17-AMC-395

March 14, 2018

1.0 Introduction

AMC Atlantic Metallurgical consulting was contacted by Hatch, St. John’s, NL to determine the root cause of cracks detected of a welded penstock used for NL Hydro.

The objective of this report is to determine the root cause of failure of the penstock and to investigate the steel specifications through mechanical testing and chemistry of the steel used. The investigation of the cracked item involved the following:

1. A detailed visual inspection.
2. Chemical analyses of the base metal and weld metal.
3. Mechanical testing of the penstock material which includes tensile and hardness testing.
4. Examination of the fracture surfaces and the presence of any anomalies or defects pertinent to the failure.
5. Metallurgical investigation of the microstructural samples taken from the different locations to verify the steel microstructure, the effect of welding processes on microstructure, and any other microstructural features that might be related to the failure.

2.0 Visual Examination

The item under investigation was delivered to AMC as a one piece as shown in Figure 1. Measurements of the location of features of the fractured plate were made using a measuring tape. The zero reference is shown at the top of the image in Figure 1. There was a large crack in the plate that extended parallel and adjacent to the longitudinal weld for approximately 43 inches of the 99 inch plate length. One end of the crack is shown in Figure 2, near the 39 inch mark. The mid length of the crack is shown in Figures 3 and 4, while the opposite end of the crack is seen near the 82 inch mark in Figure 5.

Figure 6 shows the end of the crack near the 39 inch mark on the opposite side of the welded plate, what would have been the outside surface of the pipe in service. The crack at this end of the plate appears to be away from the weld edge, traveling in the base metal. Figure 7 shows the crack in the plate from the 52 inch location to the 72 inch location. In Figure 7 crack features are apparent near the 65 inch mark and the 71 inch mark. The end of the crack near the 81 inch mark is shown in Figure 8. The transition in the width of the weld is shown in Figure 9, indicated by a black line. This transition is believed to be the extent of the repair weld, with the original longitudinal weld shown on the left of the black mark. The end of the crack near the 81 inch mark is shown in Figure 10, indicated by a black mark. The feature identified near the 65 inch mark is shown in a closer view in Figure 11. It is noted that the fracture surface appears shiny as well as having a good deal of corrosion product and debris present.

The plate was sectioned to allow for cleaning and examination of the fracture surfaces. The plate appeared to have significant residual stresses present, as one section of the plate displaced away from the main body of the plate when it was cut. The final displacement of the cut section is shown in Figure 12. After sectioning the plate was cleaned of soil and loose debris using water, detergent and a soft brush. The corrosion product was then removed using a rust removal product (Evaporust) that does not attack the underlying metal.

The crack appeared to progress along the toe of the weld for virtually the full length of the fracture. The fracture was apparent along the raised weld bead profile. The majority of the crack length showed a flat region extending from the internal surface through the thickness of the plate for a depth of approximately 3mm. The fracture surface shown in Figure 13 shows the flat area as well as a change in orientation of the fracture progression through the plate. This feature along with other were investigated further by removing samples for metallographic examination. Sections were also removed and provided to Wayland Engineering for Metallography and SEM analysis. The location of samples is illustrated in Figures 14 to 20. The location of tensile specimens and macro sections are shown in Figures 14, 15, and 16. An additional tensile specimen was taken adjacent to the T2 location, with the reduced section in the base metal to allow for determination of the yield strength of the base metal. The location of the samples was also identified with the distance along the plate, as determined originally for ease of identification.

Specific areas identified for metallographic included the Macros shown in Figures 14, 15, and 16 as well as sections that were mounted in Bakelite and ground and polished. Areas of interest that were examined by metallography were:

1) MW42 - An area where the crack deviated away from the toe of the weld as shown in Figure 17
2) MW69 – An area where a secondary crack propagated between weld passes, parallel to the main fracture as shown in Figure 18
3) MW71 – An area where there were crack like indications in the plane of the plate along with a flat zone at the plate internal surface as shown in Figure 19
4) MW79 – An area where there is a clear distinction between the flat zone along the plate internal surface and the zone near the outside surface as shown in Figure 20

3.0 Metallography and Micro Hardness Testing

In all, 7 samples from the fractured area were prepared for metallography. In addition to the 4 macro samples, 3 micro sections were taken from different locations identified previously. Micro hardness measurements were performed on the macro section M4B. The results did not show any evidence of hard spots that might have contributed to the cracking. The results show that the hardness of the base metal was in the range of 151-164 Hv10. The weld metal shows a little bit higher hardness in the range of 175-183 Hv10. The micro hardness of the area close to the cracks was also tested. The micro hardness was in the range of 175-182 Hv10. The results show that there is no exceptional higher hardness values measured which might be a result of formation of hard phases due to welding. The microstructures present adjacent to the weld toes was pearlitic, with no evidence of martensite formation.

Figure 15 shows the polished section of macro M1 from near the 15 inch location on the plate. Although visually there did not appear to be any cracking, it is evident that there was a crack created in service. The as-polished section shows that a crack had propagated along the toe of the weld for a distance of approximately 0.75 mm into the plate. An unusual feature was that an interplanar fracture then developed. Figure 16 shows the etched microstructure from the toe of the weld to the interplanar fracture. There were no unusual microstructures evident to account for the initiation of the original crack.

Figure 17 shows a crack in the M3 sample from the 42 inch location after etching. The crack morphology appears similar to that seen in the M1 sample, except that there appeared to be greater deformation opening the original crack. The lack of deformation along the fracture surface shown on the left indicates that the through thickness crack may have been present initially, with the interplanar crack developing later under stresses that caused the crack to open as in bending. The location of the interplanar crack was approximately 0.86 mm below the plate surface.

The crack in macro M4B shows a through thickness crack along with two short interplanar cracks propagating at approximately 0.72 mm below the plate surface as seen in Figure 18. The through thickness crack appears to have widened from its initial profile, but this appears to have been due to physical displacement and not due to corrosion. The M4B macro is shown etched, and with Vicker HV10 hardness points in the HAZ in Figure 19. The appearance of the crack in Figure 19 shows that the sides of the crack were likely offset by tension along the internal surface that was concentrated along the weld toe.

The etched microstructure in Figure 20 shows the MW42 sample. At this location a small through thickness crack developed along the toe of the weld, with the main fracture approximately 10 mm away. One thing of note is that the profile of the weld at this location is flatter than seen over the majority of the plate length. The crack displacement at this location appears to be due to tensile stresses along the internal surface of the plate, and not due to corrosion.

Another area of unusual fracture was apparent in MW69 as shown in the unetched condition in Figure 21. The crack appears to initiate as a vertical or through thickness crack and then turns 90 degrees and propagates interplanar. In the etched condition shown in Figure 22 it is apparent that the crack initiates between the weld passes and turns interplanar once it passes through the weld metal into the base metal. A greater magnification in Figure 23 shows the pearlitic microstructure in the weld and base metal.

The examination of the MW79 sample shows the approximately 3mm deep flat area seen on the fracture surface. This area shown in Figure 24 corresponds to the HAZ present at the toe of the weld. At this location it appears that the through thickness crack is relatively flat, with the surface transitioning to a rougher appearance and at a different profile as the crack propagated through the plate. The microstructures were pearlitic with no unusual hard locations that would promote cracking.

The as polished section from location MW71 shows deep interplanar crevices on the fracture surface as shown in Figure 25. The etched cross section in Figure 26 shows that the through thickness crack originates at the weld toe and propagates through the HAZ generating a relatively flat surface. Several interplanar crack open up once the crack is approximately 1.6 mm below the surface of the plate.

Figures 27, 28, and 29 show inclusions that were typically found in the samples. These inclusions were likely manganese sulphide, but little effort was made to identify or quantify these inclusions. The orientation of these inclusions corresponded to the interplanar crack observed at multiple locations along the main fracture. It does not appear that the main fracture was due to these inclusions, but the manner in which the secondary cracks developed and propagated could have been due to the presence of these inclusions, some exceeding 1 mm in length.

4.0 Mechanical Testing

In order to verify the mechanical properties of the penstock materials, 3 samples were prepared for tensile testing. One as a base metal (no weld) and the other two were transverse weld joints. The results are shown in Table 1. The results show that the mechanical properties of the base metal matches the specified Grade B ASTM285/A285M-12 steel shown in Table 1. We could not determine the yield strength from the transverse weld tensile samples so a base metal sample was removed in the same orientation as the fracture. The fractured tensile specimens are shown in Figure 30. The fractures appear 100 % ductile and show considerable ductility in the reduction in the cross section.

Table 1. Mechanical properties of penstock material.

Material / Property	Elongation %	Maximum Load (KN)	Maximum Stress (MPa)	Yield at 0.2% (KN)	Yield at 0.2% (MPa)
Weld joint 1 Transverse weld	23	163.1796	482.81	------	-------
Weld joint 2 Transverse weld	20	158.9037	560.72	-------	--------
Base Metal	40.96	114.1299	431.06	62.8169	237.26
Grade B ASTM285/A285M-12	28	-----	345-485	--------	165

5.0 Chemical Analysis

Chemical analysis was performed on both base and weld metal as shown in. The base material can be classified as ASTM grade B A285/A285-82 as shown in Table 2. The only comment here is the percentage of sulphur since the old specification which was issued in 82 permits up to 0.40 %. However. The newest ASTM standards limits the sulphur to 0.025 %. The pinstock material is within the range of the ASTM specifications (year 1982 issue). However, it has a 0.007 % extra sulphur based on the ASTM specification (year 2012). Knowing the age of the penstock and the current specification at the time of putting this item in use, we have no concern regarding the base material used in this application.

It is worth noting that we reviewed the chemical analysis results that were provided by the client and was performed by Cambridge Materials Testing Limited and found almost the same results. The only difference was in sulphur content of the base metal. Their value was 0.020% and our value was 0.030 %.

Table 2. Chemical analysis of base and weld metal.

Sample Element	Penstock Base Metal	Grade B ASTM A 285/A285M-82	Grade B ASTM A 285/A285M-12	Penstock Weld Metal
C	0.209	0.22 Max	0.22 Max	0.075
Si	0.056	N/A	N/A	0.309
Mn	0.520	0.98 Max	0.98 Max	1.021
P	0.0047	0.035 Max	0.025 Max	0.005
S	0.0320	0.040 Max	0.025 Max	0.013
Cr	0.041			0.054
Mo	0.006			<0.003
Ni	0.082			0.036
Al	0.005			0.004
Co	<0.008			<0.008
Cu	0.037			0.037
Nb	<0.005			0.007
Ti	<0.001			0.041
V	<0.002			0.018
B	<0.0005			0.001
Fe	98.9			98.3

6.0 Discussion & Conclusions

The materials used in the construction of the penstock have been confirmed to conform to ASTM A285 requirements for strength and ductility. There did not appear to be any issues regarding the chemistry of the base material or the weld consumable. There did not appear to be any issues regarding hardness of the HAZ.

The fracture appearance shows that there was a 3mm deep section along the toe of the weld that propagated through the thickness of the plate. This initial fracture was located almost exclusively along the toe of the weld where the weld profile was raised. Along this initial fracture zone there did not appear to be any significant corrosion where the initiation would have occurred or along the fracture surface. The fracture appeared to change the mode of fracture and orientation of the propagation through the plate. In areas where there was only the partial fracture there was interplanar fracture apparent at many locations. The appearance of the fractures suggested high tensile stresses along the internal surface of the plate, similar to the stresses that would result from bending. From the complications of the repair from the initial failure repair, there likely was a poor alignment of the plate that resulted in high tensile stresses immediately after welding. There appears to be a subsequent loading event that resulted in the complete fracture of the penstock plate. The magnitude of the stresses required to cause a failure would depend upon the abnormal stresses due to the residual stresses and those from the misalignment. Areas away from the initial repair area also showed evidence of initial cracking that did not result in complete fracture, suggesting that the misalignment created a significant portion of the stress that resulted in the failure.

If you have any further questions regarding this investigation, please contact the undersigned.
Sincerely,

J. Scott MacIntyre, P.Eng.
Manager, Forensic & Failure Investigation

Figure 1 Failed Penstock plate as received

Figure 2 Penstock plate showing one end of the fracture near the 39 inch mark

Figure 3 Crack in the plate from the 45 inch mark to the 65 inch mark

Figure 4 Crack in the plate from the 57 inch mark to the 75 inch mark

Figure 5 Crack in the plate from the 70 inch mark to the end of the crack near the 82 inch mark

Figure 6 End of the crack on the outside of the Penstock showing the crack arrest in the base metal.

Figure 7 Crack section from the 52 inch mark to the 72 inch mark showing crack travel along the weld.

Figure 8 Penstock outside surface showing crack from 65 in. to 82 in.

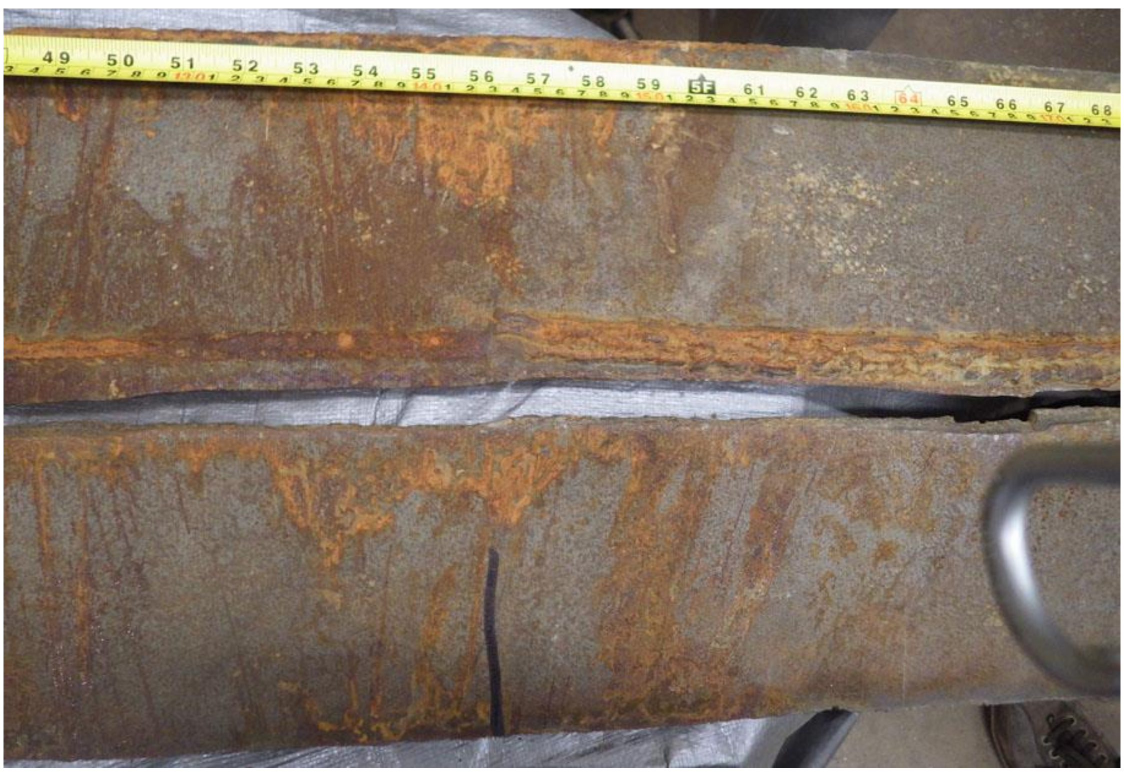

Figure 9 Crack near the transition of original weld and repair weld

Figure 10 Crack arrest location in base metal offset from weld

Figure 11 Feature at 65 in. location near edge of weld.

Figure 12 Photograph of the plate as it was being sectioned showing deformation due to residual stresses

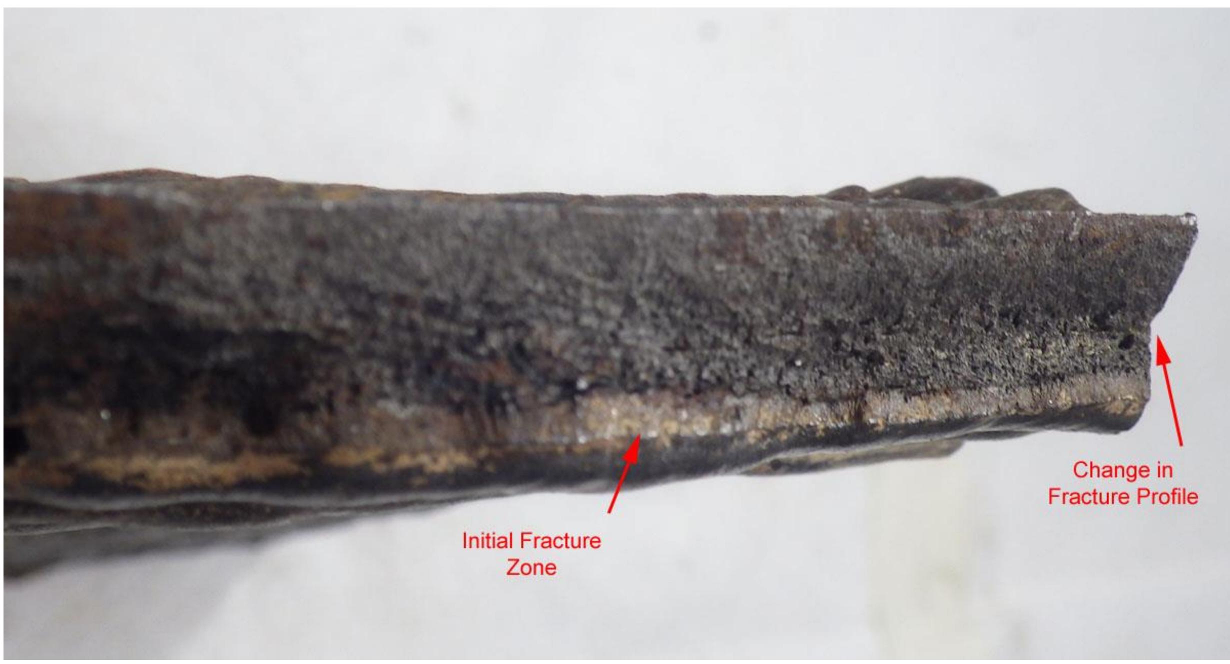

Figure 13 Photograph showing the fracture surface illustrating different fracture modes

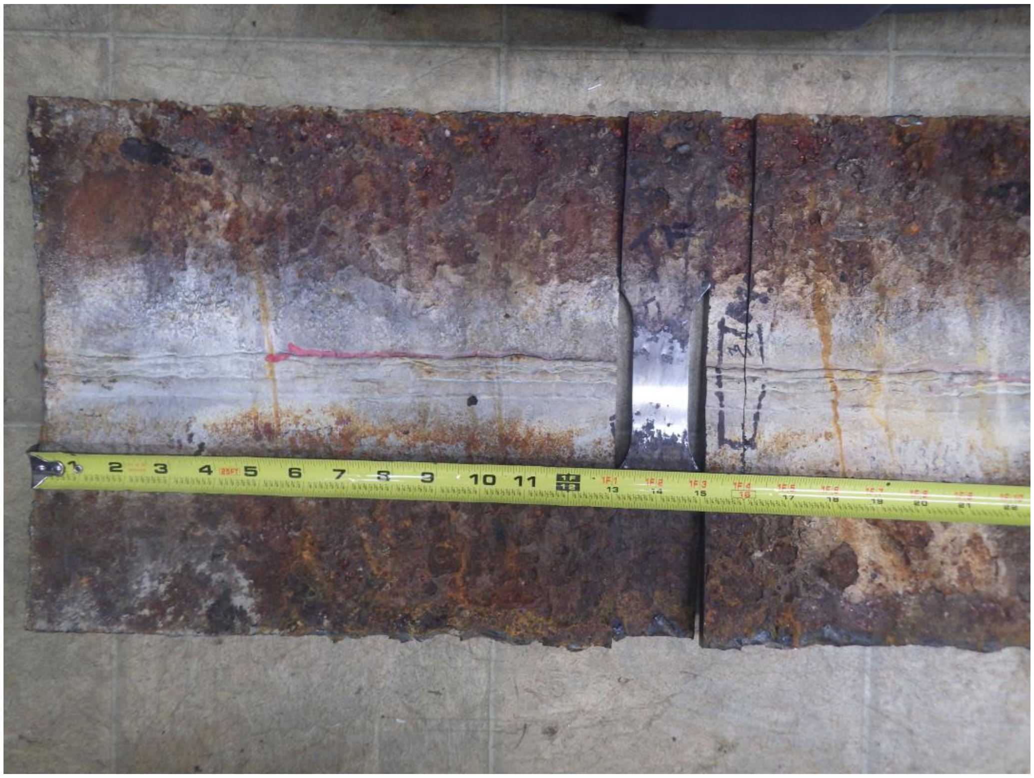

Figure 14 Photograph showing the location of Tensile 1 (T1) and macro 1 (M1) between the 13 & 16 in. marks

Figure 15 Photograph showing the location of Tensile 2, Macros M4A & M4B between the 72 & 75 in. marks

Figure 16 Photograph showing the location of micrographic section the 39 & 42 in. marks

Figure 17 Photograph showing the location of a metallographic sample from near 42in location

Figure 18 Photograph showing the location of a metallographic sample from near 69in location

Figure 19 Photograph showing the location of a metallographic sample from near 71in location

Figure 20 Photograph showing the location of a metallographic sample from near the 79 in. marks

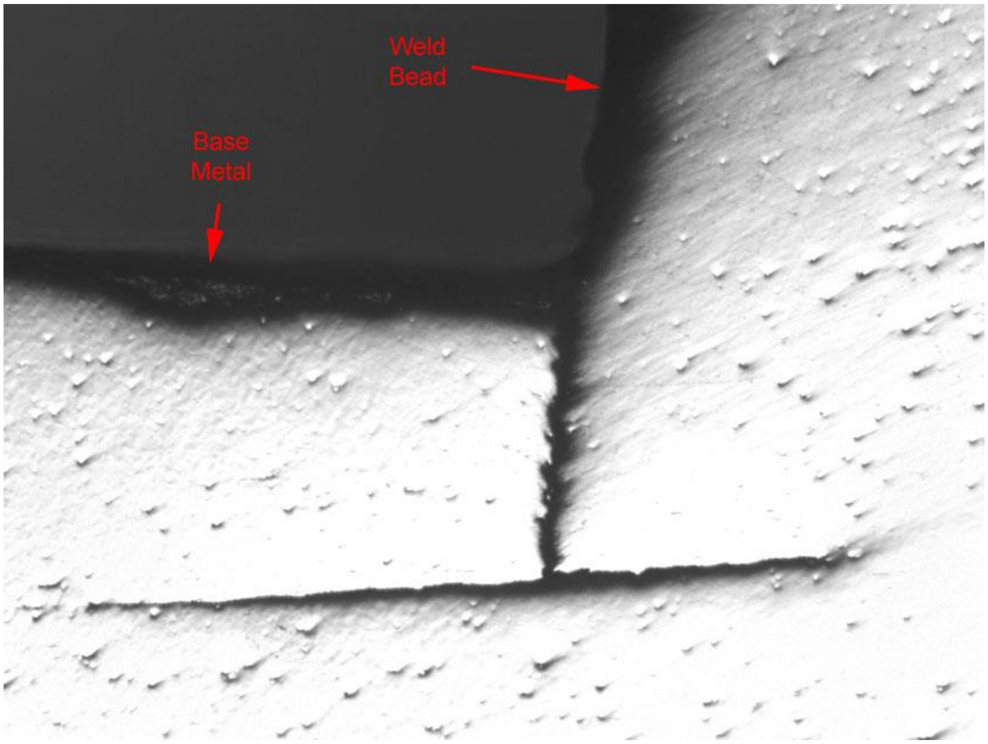

Figure 21 Photograph showing the crack in the M1 sample from near the 15in location

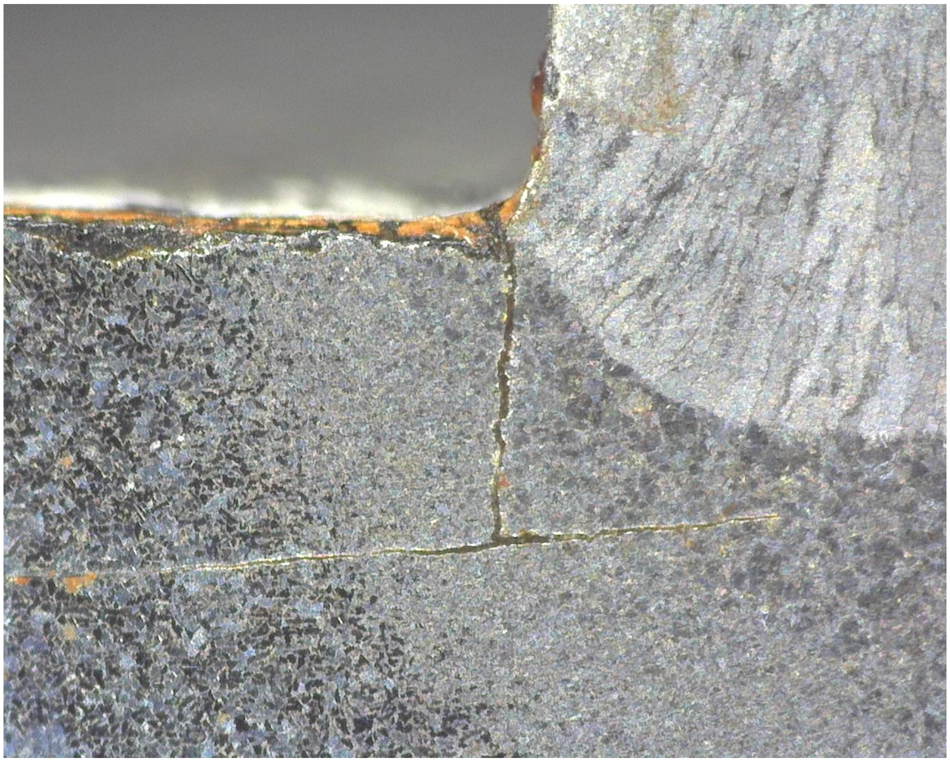

Figure 22 Photograph showing the crack in the M1 sample at the 15in location after etching

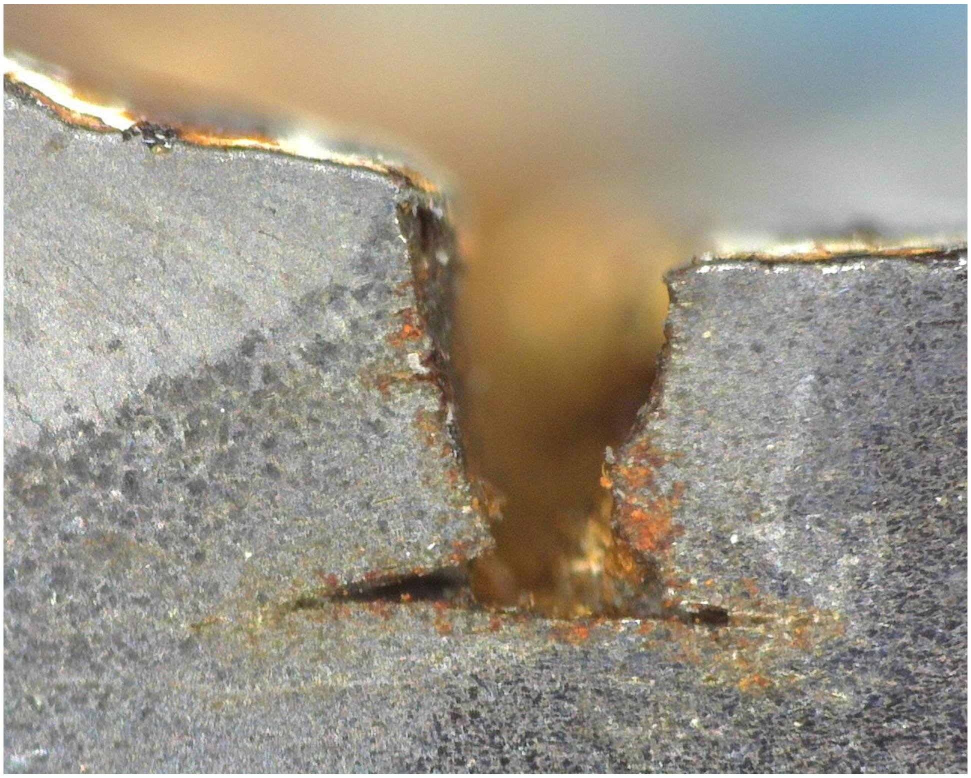

Figure 23 Photograph showing the crack in the M3 sample at the 42in location after etching

Figure 24 Photograph showing the crack in the M4B sample at the 86.5in location

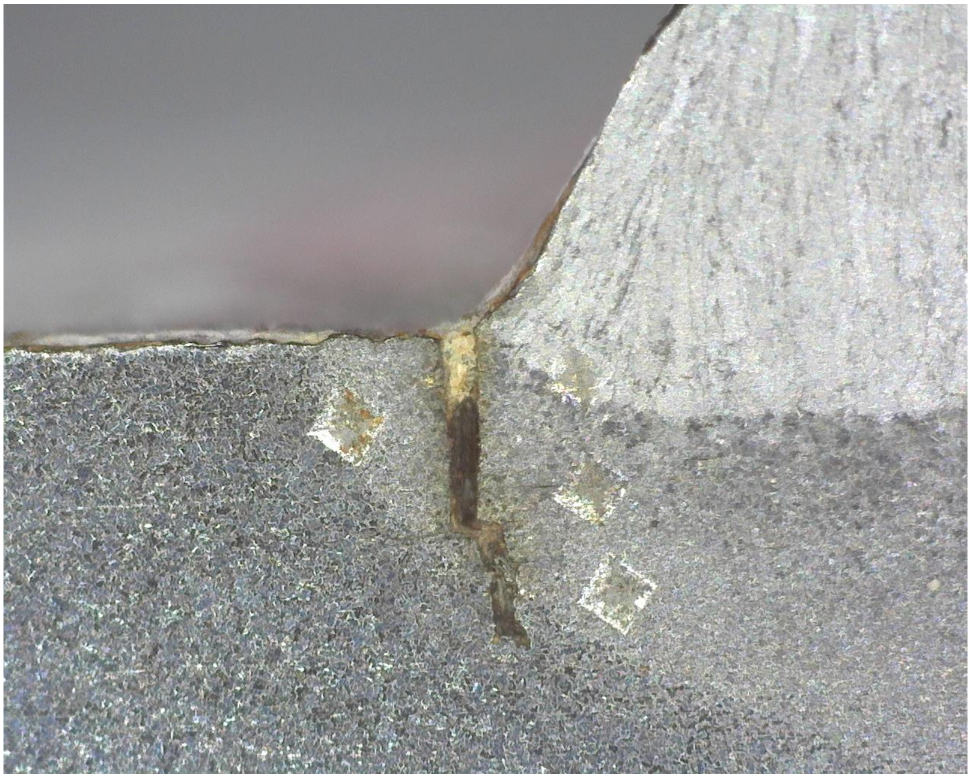

Figure 25 The crack in the M4B sample at the 86.5in location after etching & hardness testing

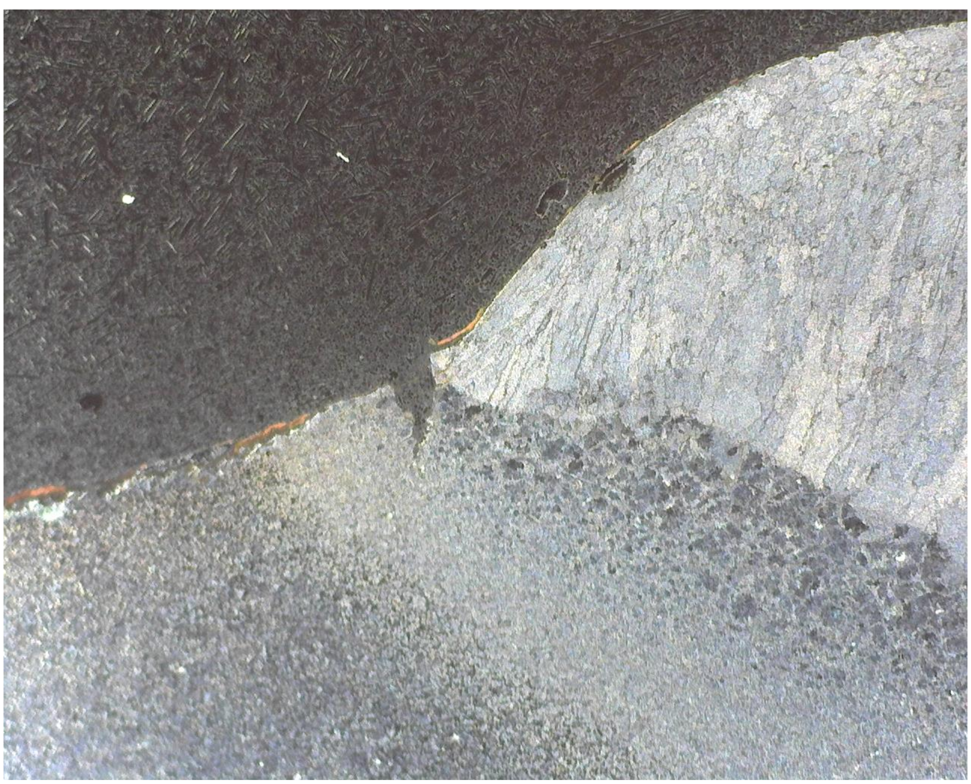

Figure 26 Photograph showing the crack in the MW42 sample at the 42in location after etching

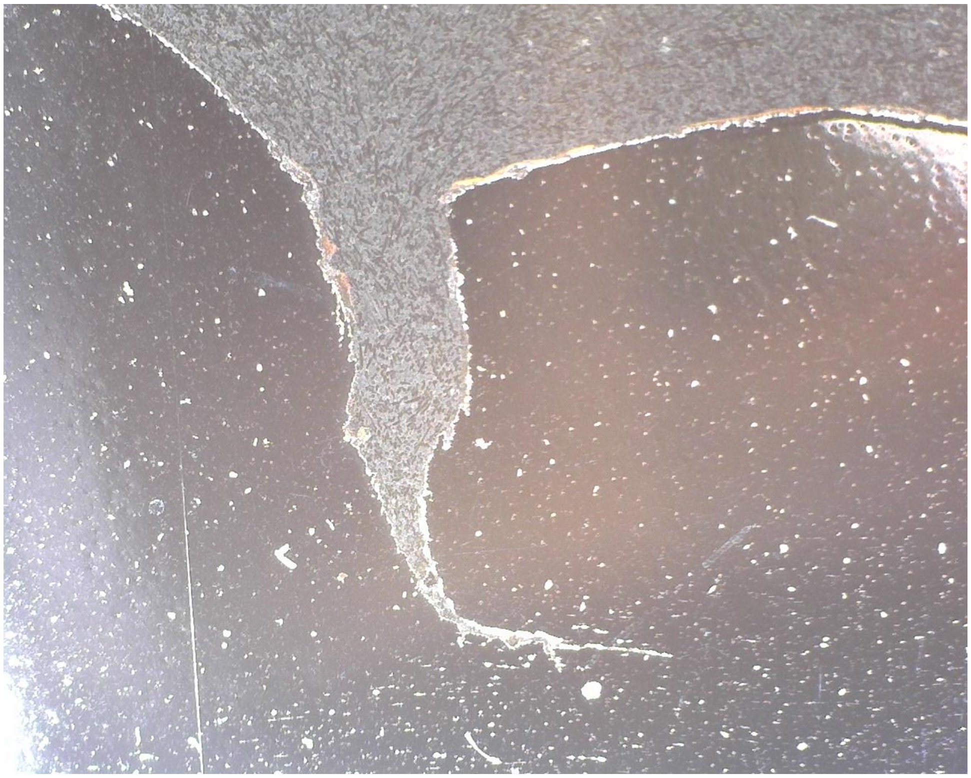

Figure 27 Photograph showing the crack in the MW69 sample at the 69in location, as polished

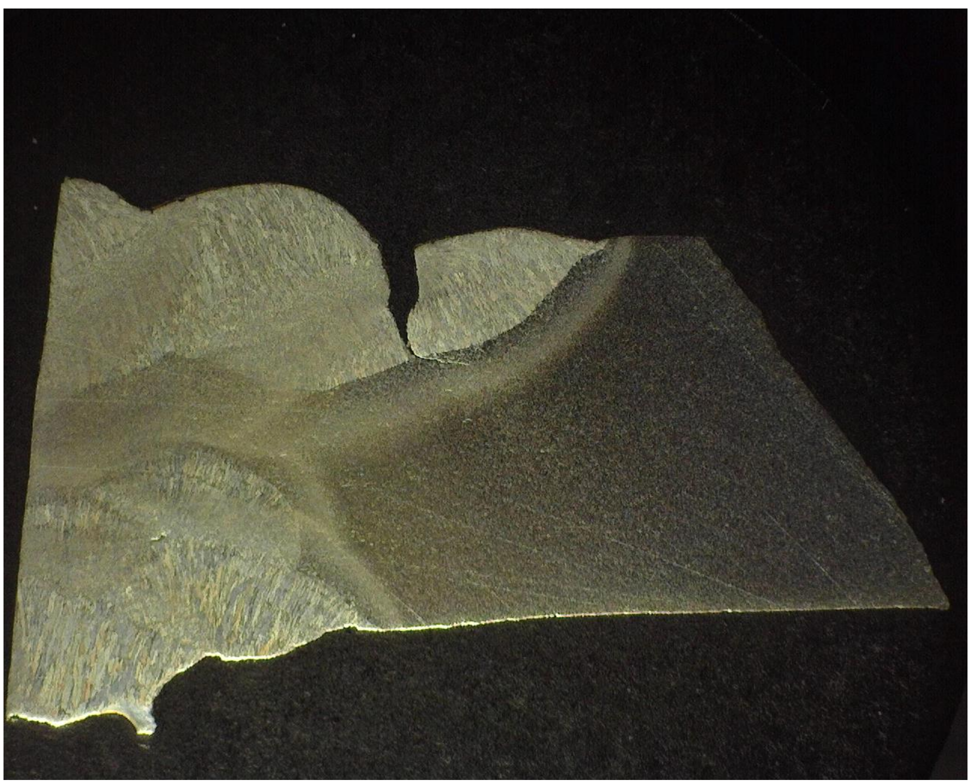

Figure 28 Macrograph showing the crack in the MW69 sample at the 69in location, etched

Figure 29 Macrograph showing close-up of the crack in the MW69 sample at the 69in location, etched

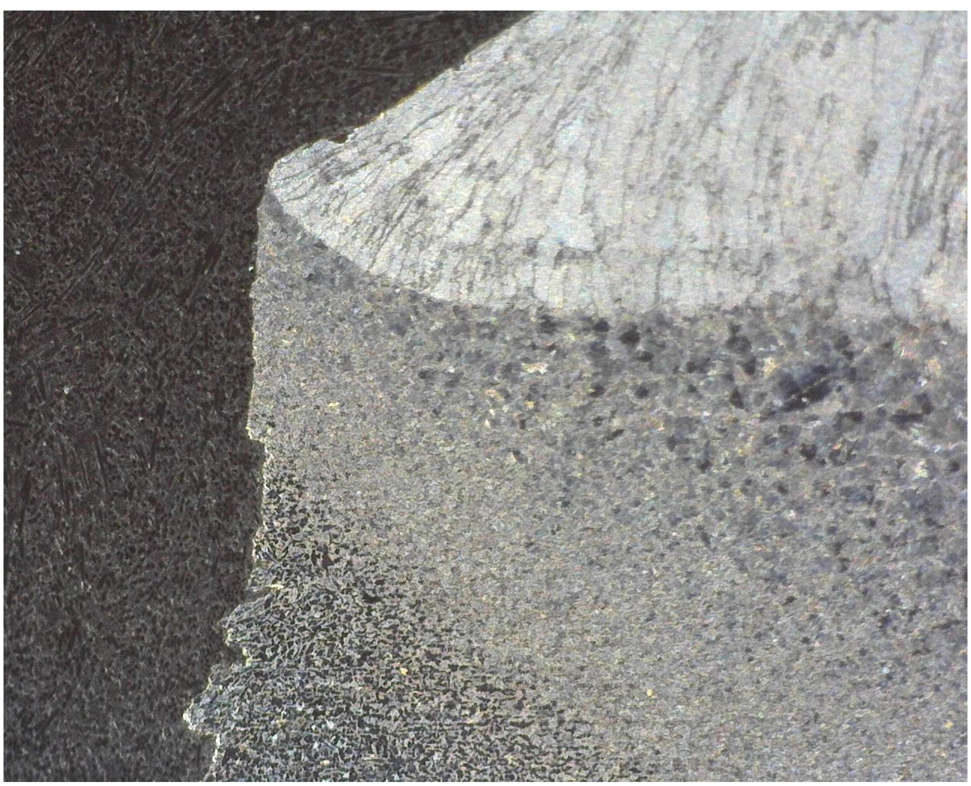

Figure 30Macrograph showing the microstructure near the crack in the MW79 sample at the 79in, etched

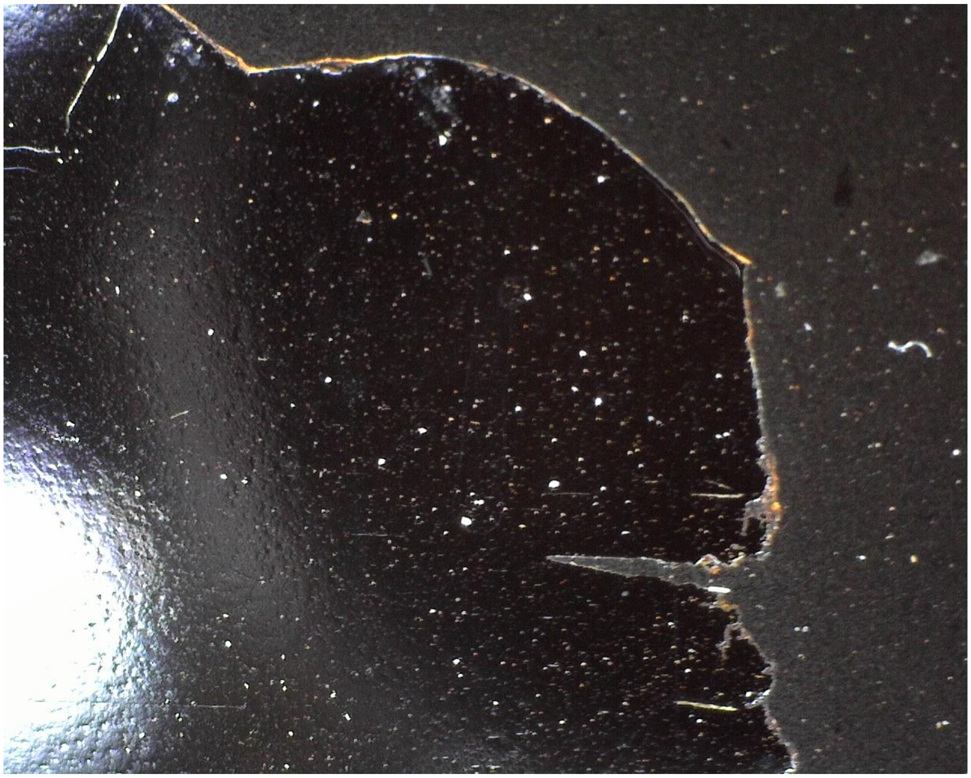

Figure 31 Macrograph showing the crack in the MW71 sample at the 71in location, unetched

Figure 32 Macrograph showing the crack in the MW71 sample at the 71in location, etched

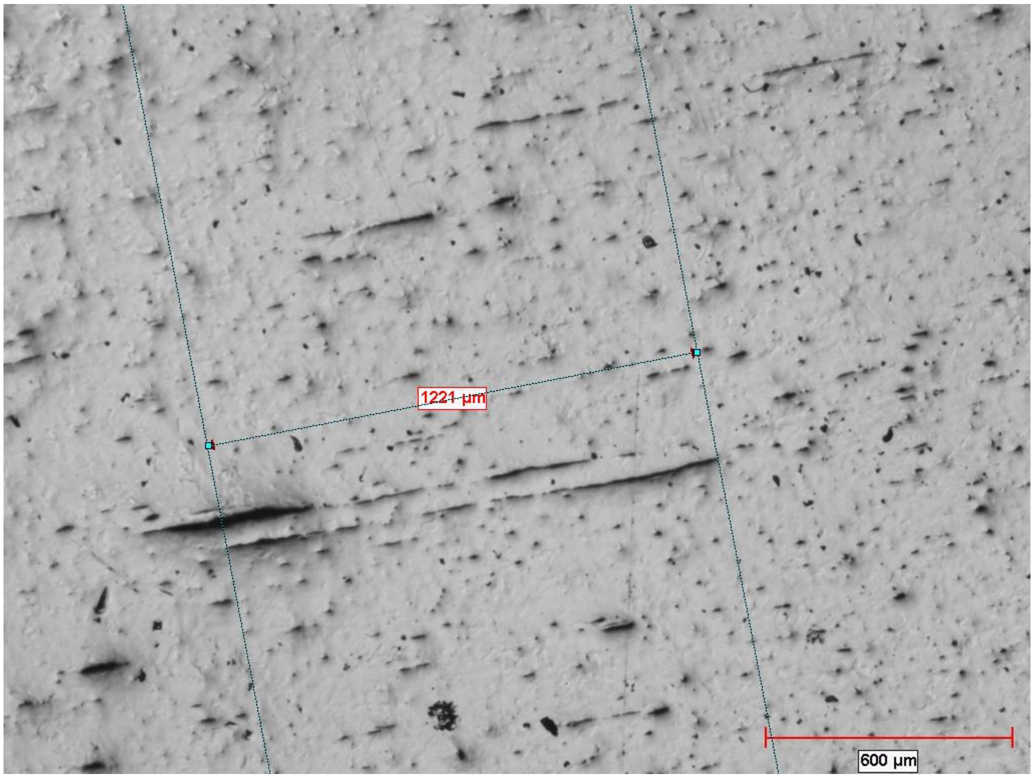

Figure 33 Inclusions in MW69 unetched

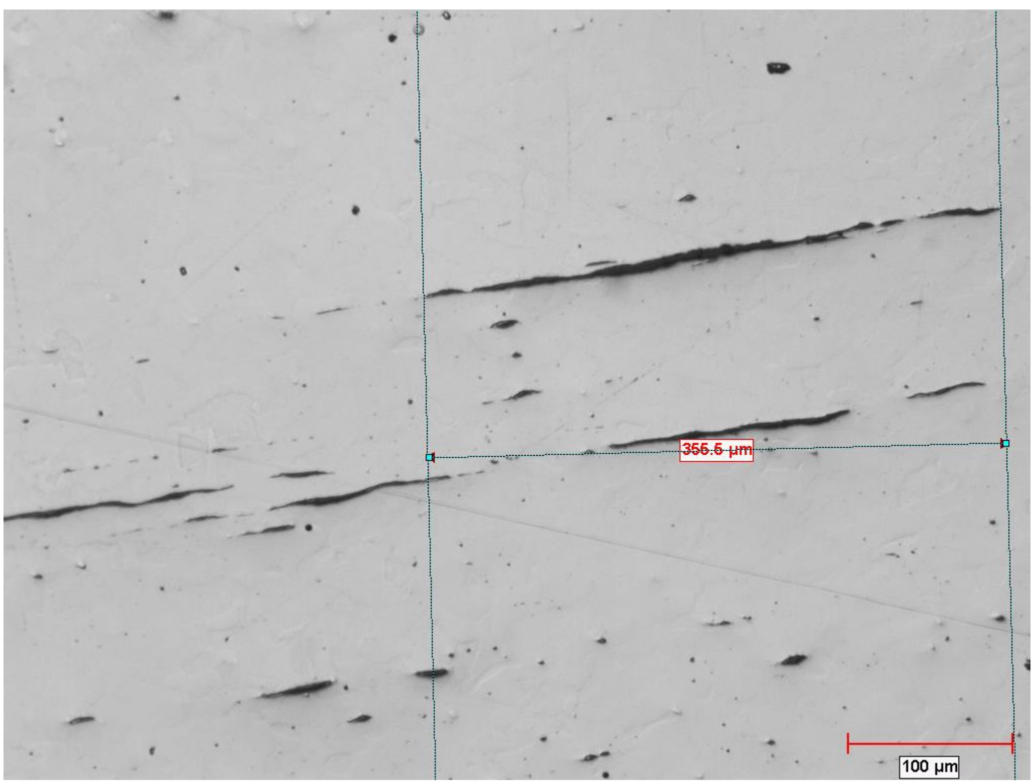

Figure 34 Inclusions in MW69 unetched

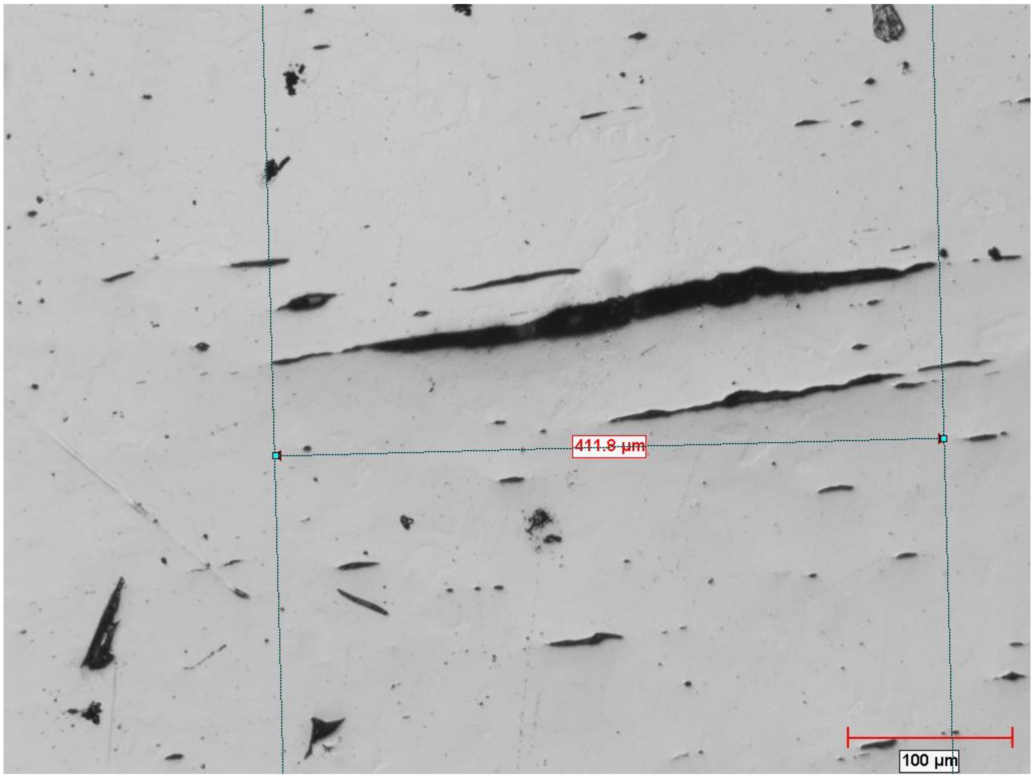

Figure 35 Inclusions in MW69 unetched

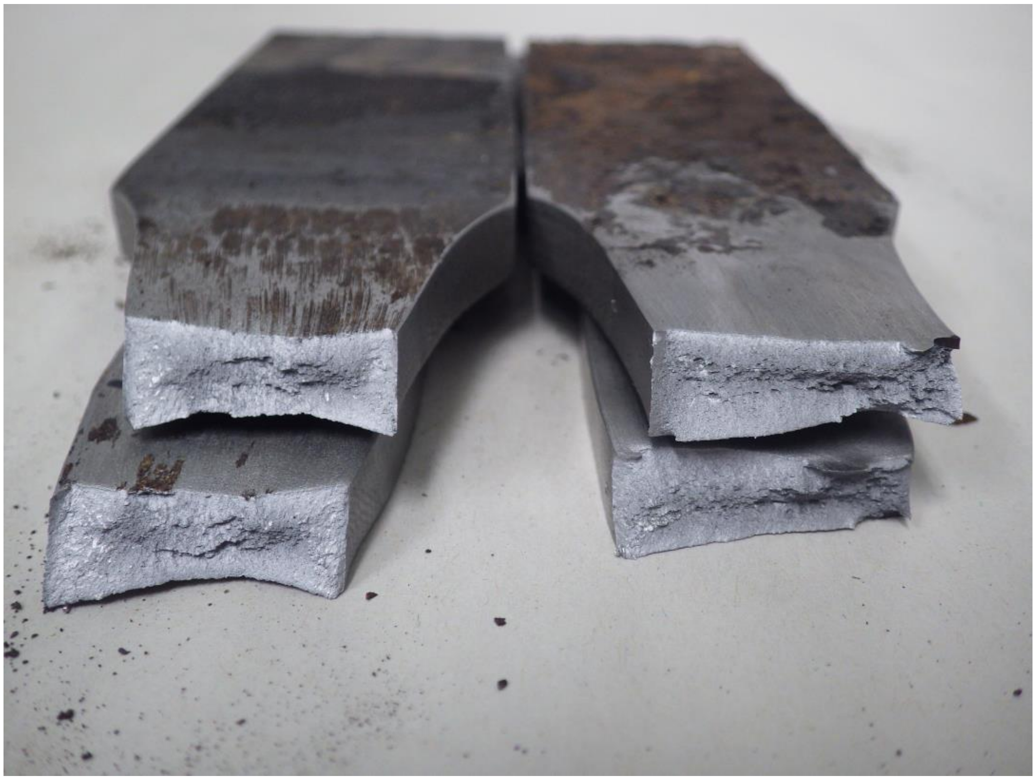

Figure 36 Tensile specimens showing fracture surfaces

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HATCH

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SURGE AND TROUBLE REPORT ANALYSIS

Report No: 7078
Event Description: Generator #6 Tripped at Bay d'Espoir Generating Station (BDE)
Event Date & Time: June 30, 2018 at 15:08:26 hours NDT

Sequence of Events:
At 15:08:26 hours NDT, generator #6 at the Bay d'Espoir Generating Station (BDE) tripped after the operation of the unit's lockout switch. This event did not lead to any customer outages.

Generator #6 at BDE was returned to service at 12:80 hours NDT on July 1.

Protection Information:
Relay Targets: 87N 86A/G6T6 86B/G6T6
Fault Type: N/A *Permanent*: N/A
Clearing Time: N/A *Reclosing:* N/A

Analysis and Conclusions:
The protective relay that operated the lockout switch which tripped Generator #6 was a "split phase differential" relay, which is designed to detect turn-to-turn shorts in the generator stator by comparing the current flow through two sets of parallel windings. The relay had recently been replaced as part of a protection upgrade on Generator #6. A review of the relay records showed not a fault, but rather a background current due to an imperfect balance between the currents flowing in the two sets of parallel windings that was fluctuating between approximately 70 amperes and 130 amperes.

The old protection relay was set at 80 amperes in 1972, but the setting was increased to 160 amperes in 1995. The revised setting was updated in the setting database but there was no printed copy of the setting letter on file at Hydro Place. The new relay was installed with settings based on the old 1972 setting of 80 amperes. If the setting had been based on the 1995 setting of 160 amperes, the relay would not have tripped for the current levels recorded in the relay records for this event.

The relay settings were updated to 160 amperes to align with the 1995 settings and avoid a reoccurrence.

Recommendations:
NL Hydro P&C Engineering should review their information management processes to see if changes are required.

Issued By: Jeffrey Streifling, P. Eng.
Asset Management and Reliability

Issue Date: 2018/07/24

Checked By: AGB

Approved By: AGB

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HYDRAULIC GENERATION
FORMAL FORCED OUTAGE INVESTIGATION FORM

FORMAL FORCED OUTAGE INVESTIGATION FORM:

(Note: This form is to be completed by the Lead Investigator following a Forced Outage. It is to be used to document the investigation and any associated remedial actions.)

Location/Unit #:__BDE – Unit 2____ WO#: 1347380

Start Time & Date	End Date / Time	Duration	Outage / Derating Type	
09/04/2018 10:35	09/05/2018 16:05	29.5 hrs	X	Sudden Forced Outage [1]
				Immediately Deferrable Forced Outage [2]
				Deferrable Forced Outage [3]
				Starting Failure Outage [4]
				Forced Derating [5]

Lead Investigator:___Samantha Smith_______
Other Investigator(s):____________________
Investigation Completed Date:___Oct. 1, 2018________

SUMMARY

On Tuesday, September 4, 2018, BDE Unit 2 was taken offline at 10:35 to investigate rotor ground fault alarm.
Prior to this, the "Excitation Failure – Rotor Ground Fault F75" alarm came in twice:

2018-09-02 @ 22:25 – alarm was successfully reset
2018-09-03 @ 08:55 – alarm came in and was unable to reset

After the unit was removed from service on 2018-09-04, the Protection and Control Department conducted an inspection on the Unit 2 exciter and found no issues. Subsequently, a permit was put in place for more detailed inspection. During this inspection, the Electrical Department discovered excessive carbon build up and that the carbon bushes were severely worn.

All brushes on Unit 2 were replaced with a new brush type N3 during the unit annual in 2018. Brushes were originally type Y4609, the brush type that has been inventory in Bay d'Espoir (JDE inventory number 65300012). The unit returned to service from the annual outage on 2018-08-14 @ 18:42. Since returning from annual, Unit 2 accumulated 497.48 operating hours. It is noted that the typical time seem between brush replacements on BDE Unit 2 has been approximately 2 years of wear.

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[1] Sudden Forced Outage: the occurrence of a component failure or other condition which results in the unit being automatically or manually tripped.
[2] Immediately Deferrable Forced Outage: the occurrence of a component failure or other condition which requires that the unit be removed from service within 10 minutes.
[3] Deferrable Forced Outage: the occurrence of a component failure or other condition which requires that the unit be removed from service from10 minutes up to and including the very next weekend.
[4] Starting –Failure Outage: the unsuccessful attempt to bring a unit from a shutdown state to synchronism with the electric system within a specified time interval. The specified time interval may be different for individual units and should allow a reasonable time for the unit to pick up load.
[5] A reduction of generating unit capacity in excess of 2 % of its Maximum Continuous Rating resulting from a component failure or other condition which requires that the generating unit be de-rated at once or as soon as possible up to and including the very next weekend.

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HYDRAULIC GENERATION
FORMAL FORCED OUTAGE INVESTIGATION FORM

In response to the excessive wear on the brushes, during the outage, all brushes on Unit 2 were replaced with the original type Y4609 brushes from inventory. Additionally, any other type N3 brushes that were installed during the annual outages on other units were also inspected, removed and replaced with the original type Y4609 brushes.

INVESTIGATION

Through the investigation process, the following root causes were identified:

Inadequate Specification on Requisition
The tender documents created in December 2017 for the procurement of new carbon brushes were inadequate. There was no detailed specification included which should have included necessary information on required brush grade. The only technical information provided contained information on the brush dimensions and reference to a unique manufacturer's brush grade (M56 – serial #:Y4609).

Inadequate Evaluation of Change
Brush grade should not have been changed without proper thorough technical review. The review of bid submissions for the above mentioned tender was inadequate. Five bids were received with three bidders pricing in the ~$55/brush range, and two in the $30/brush range. The previous supplier of the M56 brushes had submitted a bid ($53.99/brush). The lowest quoted price was disqualified based on the manufacturer being different that requested ($28.64/brush). The awarded bid was to Mill Supply ($29.95/brush) who in their submission noted brush grade as being N3 and supplied previously in 1998. After completed a JDE WO review, it was determined that these previously supplied N3 brushes had a history of excessive wear in the period following the supply in 1998. All N3 brushes had been removed by Q1 2000. (See WO#s 91551, 91555, 91557, 137382). A thorough review of the proposed change to brush grade should have included a historical review.

REMEDIAL ACTIONS

1. Develop carbon brush specification documents for each specific unit and update JDE Equipment Info to include this information.
2. Formally document any changes to current brush specs using the Management of Change.
3. Ensure all PM checksheets are updated to latest revision for brush inspection information.

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HYDRAULIC GENERATION
FORMAL FORCED OUTAGE INVESTIGATION FORM

CONCLUSION

The development of detailed specifications for carbon brushes for each unit in the hydraulic fleet as well as a more thorough technical review of submitted bids will prevent a situation such as this from occurring in the future. Any changes required in the future should be documented and follow the formal Management of Change process.

Unrelated to this specific outage, but still a critical take away, is the requirement to verify and complete outstanding updates to ALL unit PM check sheets, as per the BDE Unit 7 2017 outage TapRooT Report, to include the latest revision of required brush inspections. The review of current sheets identified discrepancies from one PM check sheet to another.

ACTION ITEMS

Item	Work Order	Description	Target Date	Person Responsible
1	XXXXXX	Develop carbon brush specification for each unit.	**July 2019**	**Brent Peddle**
2	XXXXXX	Use MoC Process to document changes to brush specification.	**July 2019**	**Brent Peddle**
3	XXXXXX	Update any outstanding PM check sheets to reflect most recent information for brush inspection.	**April 2019**	**Brent Peddle**
4	XXXXXX			

REVIEW SIGN OFF

Operations Manager:______________________ Date:______________________

LTAP Manager:______________________ Date:______________________

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EXPLOITS GENERATION
FORCED OUTAGE REPORT

FORCED OUTAGE DATA:

Unit #:**GF9 (Beeton)**

Start Time & Date	End Date / Time	Duration	Outage / Derating Type	
			X	Sudden Forced Outage [i]
				Immediately Deferrable Forced Outage [ii]
				Deferrable Forced Outage [iii]
				Starting –Failure Outage [iv]
				Forced Derating [v]
07:50 on Mar.03	21:30 on Mar.03 13.8MW	14hr20m		
02:40 on Mar.04	10:23 on Mar.04 16.3MW	7hr43m		
11:33 on Mar.04	12:15 on Mar.04 12.1MW	0hr42m		
12:50 on Mar.04	16:35 on Mar.04 **26MW**	3hr45m		
		26hr30m		

SUMMARY

Unit GF9 is a Vertical Francis hydroelectric unit with a generator rated output of 33.3MVA.
On March 3rd @ 07:50 Gf unit #9 Governor Processor faulted (error P01:C62) and as a result unit governor shut the unit down. After performing checks and troubleshooting it was found the processor had lost its program after the error reset. Program was reinstalled and system reset. The unit was put back online again at 21:20 but only able to get to 49.4% with the gates sticking in this position. Unit left at that position but tripped again at 02:40, March 4th on 94E1 & 94E2.
With maintenance crews available again the next morning, the unit was tried several times but not able to load properly. A decision was made to install the latest program from American Governor. This process took longer than expected due to an incompatibility with the laptop being used for programing and the governor processor. After minor changes to the latest program the unit was put online again at 16:35 at 70% gate.

INVESTIGATION

Preliminary investigation by operations and maintenance revealed governor processor had faulted causing a governor fault, thus tripping the unit. Conversation with Rockwell & IEAS confirmed that error code meant that there had been a spike in processor supply voltage. Further investigation showed program needed to be upgraded to be compatible.

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EXPLOITS GENERATION
FORCED OUTAGE REPORT

REMEDIAL ACTIONS

GF4 increased to 100%.
GF 5 & 8 units put online

CONCLUSION

Both processor and program needed upgrading.
Governor program needs further fine tuning around unit's rough loading zone.

Recommendations

During April annual shut to have Alstom, American Governor, & IEAS resolve issues around programming and unit loading through its rough zone.

Action Items

Arrangements are being made for manufacturer representatives and consultants to be on site during the annual outage.

ACTION ITEMS

Item	Work Order	Description	Target Date	Person Responsible
1	1249220	American Governor to address programing and tuning of governor.	**April 28 2017**	**Max Hutchcraft**
2	1249220/ 1249219	IEAS/American Governor to address speed and position mode of operation through the rough zone	**April 28 2017**	**Max Hutchcraft**
3	1249235	Power supply to be thoroughly checked and spare internal processor supply installed	**April 28 2017**	**Max Hutchcraft**
4	XXXXXX			

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[iii] Deferrable Forced Outage: the occurrence of a component failure or other condition which requires that the unit be removed from service from10 minutes up to and including the very next weekend.
[iv] Starting –Failure Outage: the unsuccessful attempt to bring a unit from a shutdown state to synchronism with the electric system within a specified time interval. The specified time interval may be different for individual units and should allow a reasonable time for the unit to pick up load.
[v] A reduction of generating unit capacity in excess of 2 % of its Maximum Continuous Rating resulting from a component failure or other condition which requires that the generating unit be de-rated at once or as soon as possible up to and including the very next weekend.

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HYDRO GENERATION
FORCED OUTAGE REPORT

FORCED OUTAGE DATA:

Location and Unit #: Grand Falls Unit 4

Start Time & Date	End Date / Time	Duration	Outage / Derating Type	
08:26 on March 6, 2017	16:58 on March 17, 2017	11 days, 8 hrs, 32 mins.	X	Sudden Forced Outage [1]
				Immediately Deferrable Forced Outage [2]
				Deferrable Forced Outage [3]
				Starting –Failure Outage [4]
				Forced Derating [5]

SUMMARY

Grand Falls Unit 4 is a Vertical Francis hydroelectric unit with a generator rated output of 27.5 MVA. On March 6, 2017 @ 8:26am, Grand Falls Unit 4 (GF4) experienced a sudden forced outage. During the execution of hot work in the Grand Falls Powerhouse #2 (housing GF4) a piece of rag was ignited by a spark from an angle grinder. The smoke created from the smoldering rag was drawn into the GF4 Generator. The unit tripped offline and the generator fire suppression deluge system activated. There was no immediate impact to the system, and no effect on customers as a result of this outage.

The GF4 deluge system was installed during the 2016 Runner Replacement project. This is a new system for this unit, and was installed on the basis of safety and equipment protection.

INVESTIGATION

Below is a summary of the events which occurred that morning:
Sequence of Events:

- 7:00 am - Mechanical crew dispatched to perform work within Grand Falls powerhouse #2. Work involved the removal of a manually operated overhead door separating powerhouse #2 and powerhouse #3. This involved hot work (electric handheld angle grinder) to remove sections of door.

- 8:25 am – During the execution of the work above, a piece of rag which was located in a pipe chase in the concrete floor of powerhouse #2 was ignited by a spark. This pipe

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chase leads directly to the turbine pit of GF4. Fire was quickly extinguished by mechanical crew.

- 8:26:14 am – Smoke drawn into GF4 Generator, causing the unit to trip offline and GF4 fire system alarm received.

- 8:26:34 am – GF4 deluge system activated, GF4 sprinkler system flow alarm received. Unit engulfed in water.

- 8:27 am - Lead operator notified contractors (Bursey's Excavation & Pennecon Heavy Civil) working on fishway and main dam that a unit had tripped off-line and that there would be significant increase in additional spill at the dam.

- 8:27 am – Operations Supervisor and Operator Apprentices proceed to GF4 to investigate. Deluge system was active and water flowing across the floor of the powerhouse. Water was draining to GF4 sump, but in the process was also flowing over the GF4 sump pump controller enclosure.

- 8:27 am – Operations Supervisor and Apprentices proceed to open the electrical switch feeding the cooling water sump pump controller to eliminate electrical hazard.

- 8:35 am – Lead Operator closed valve to shut off cooling water flow to GF4 thrust bearing to keep GF4 sump level from rising too quickly (required as sump pump controller had been electrically disconnected).

- 8:40 am – No sign of fire on GF4 Unit. Apprentice proceeded to close GF4 main deluge valve to stop water supply to GF4 deluge system.

Once deluge system was isolated, investigation commenced immediately to determine the underlying causes. A local Pennecon Energy Technical Services (PETS) technician was contacted and immediately travelled to site to assist with the investigation.

The new deluge system was installed and commissioned by a subcontractor (Viking) to Voith Hydro, who had the contract for the GF4 Runner Replacement. The deluge system consists mainly of a main deluge valve and controller which automatically applies water to the GF4 generator in the presence of a fire. The controller pulls information from the installed smoke and heat detectors on the generator and from the GF4 Generator protective relay and applies logic to determine whether or not to activate.

The logic programmed into the deluge controller calls for a smoke **or** heat detector to activate on the GF4 generator **and** a signal from the protective relay to indicate an electrical fault and both the exciter breaker and main unit breaker are open (unit de-energized).

In reviewing the GF4 primary protective relay (G4-SEL-300G) immediately after the event, there were no targets showing on the relay. The PETS technician logged on to and accessed the protective relay to investigate further, and found an output contact closed and latched. This was the output to the GF4 deluge system to indicate an electrical fault and both the exciter breaker and main unit breaker are open (unit de-energized). Upon further investigation, it was determined that the programming within the protective relay was incorrect, which led to the output contact closing and latching with no electrical fault.

The programming found in the protective relay did not match the originally proposed logic to be used to provide the signal to the deluge system. The proposed logic to be used within the protective relay had been altered during the programming; it is unclear however, where this change request had come from. The commissioning procedure for the fire deluge panel required only the jumpering of signal from the protective relay and did not require the full commissioning complete with a fault signal through the protective relay.

Subsequent to the above, once a GF4 Generator smoke detector went in to alarm due to the small fire caused by the mechanical maintenance crew, the GF4 unit tripped off-line upon receiving indication of a fire. This signal was received by the GF4 Unit PLC from the Deluge panel controller. Once the unit tripped and both the main breaker and the exciter breaker opened (unit de-energized), the protective relay incorrectly indicated to the deluge system that a fault was present. This met the conditions required to activate the deluge system and apply water to the GF4 Generator.

REMEDIAL ACTIONS

With water supply to the deluge system shut off, immediate attention was turned to the drying out of the GF4 generator and investigation into water damage. A large electric heating unit was rented from a local company as well as dehumidifiers, equipment delivered to site, and electrically connected to provide heat to the unit. Generator covers were removed to allow circulation of air and heat through the unit and inspection of stator windings and rotor.

A visual inspection completed on March 6 of the generator equipment revealed 3 rotor poles (12, 13, 49) with apparent damage along the top and bottom of the poles.

Testing commenced on March 7, 2017 after applying heat to the unit overnight. The table below summarizes the insulation resistance test results over several days on the stator winding and the rotor.

Date	Time	Rotor	Stator		
		Insul. Resist. Test (500V DC) for 1 min.	Insul. Resist. Test (5kV DC) for 1 min.	Insul. Resist. Test (5kV DC) for 10 min.	PI
March 7	10:30	4.26 KΩ	545 MΩ	2410 MΩ	4.4
March 7	18:00	4.87 KΩ	500 MΩ	2380 MΩ	4.76
March 8	08:00	8.53 KΩ	457 MΩ	1500 MΩ	3.28
March 8	16:00	11.6 KΩ	420 MΩ	1250 MΩ	2.97
March 9	07:47	19.5 KΩ	380 MΩ	1030 MΩ	2.71
March 13	07:55	183 KΩ	627 MΩ	3750 MΩ	5.98

March 14	19:58	232 KΩ	627 MΩ	3860 MΩ	6.15
March 15	07:24	306 KΩ	647 MΩ	3710 MΩ	5.73
March 17	08:30	3320 KΩ	523 MΩ	2890 MΩ	5.5
March 17	13:43	2700 KΩ	572 MΩ	3300 MΩ	5.76

A pole drop test was also completed during this time. Test results are below:

Pole #	Measure Voltage	Pole #	Measure Voltage	Pole #	Measure Voltage
1	2.34	18	2.44	35	(see note)
2	2.42	19	2.37	36	(see note)
3	2.31	20	2.42	37	(see note)
4	2.37	21	2.29	38	(see note)
5	2.33	22	2.30	39	(see note)
6	2.38	23	2.31	40	(see note)
7	2.27	24	2.40	41	(see note)
8	2.55	25	2.49	42	2.37
9	2.30	26	2.33	43	2.32
10	2.31	27	2.33	44	2.33
11	2.30	28	2.36	45	2.23
12	**2.45**	29	2.35	46	2.31
13	**2.38**	30	2.40	47	2.26
14	2.47	31	2.33	48	2.31
15	2.41	32	(see note)	49	**2.28**
16	2.39	33	(see note)	50	2.38
17	2.31	34	(see note)	-	-

Note: Pole drop test could not be completed on these poles due to location.

For the above test, these numbers are all within the min/max limits (2.129 – 2.603V) established during the GF4 Runner replacement project completed in 2016. This test was completed to confirm the condition of the poles found to be with apparent damage. It was deemed that the rotor pole damage found was more aesthetic in nature with no impact on operability. These poles were then coated with an insulating paint (Glyptal) along the tops and bottoms of the poles.

Re-programming of the protective relay was completed on March 17, 2017 and testing completed to confirm the functionality of the deluge system. Please refer to Appendix A and B for report and test results.

Once testing was completed and generator covers re-installed, unit was placed back in service on March 17, 2017 @ 16:58.

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**HYDRO GENERATION
FORCED OUTAGE REPORT**

CONCLUSION

The activation of the GF4 deluge system on March 6, 2017 was due to a small fire within the powerhouse #2 and improper programming of the G4-SEL-300G protective relay. The improper programming was not identified during the commissioning of the GF4 Deluge system as a jumper was used to provide signal. Complete system commissioning was not completed to confirm system functionality with the protective relay.

This collateral damage to Rotor poles #12, 13, and 49 was attributed to the cold water from the deluge system spraying directly onto the warm rotor pole. Testing proved that the condition of the rotor poles was acceptable and that the damage was aesthetic in nature.

RECOMMENDATIONS

1. Revise the programming of the GF4 Deluge system controller to incorporate a requirement for smoke **and** heat as opposed to smoke **or** heat. This revision would be subject to the approval of FM Global.
2. Require full system commissioning on future projects and not allow use of jumpers to verify signals from vital equipment components. This will ensure system functionality once commissioning is completed.
3. Test GF9 (Beeton Unit) deluge system during outage to confirm system functionality.
4. Clean-up of powerhouse, paying close attention to pipe chases and other areas where hidden combustibles may be located.
5. Review of Hot Work Permits with the crews. Mandatory use of fire blankets during hot work around floor openings where there may be potential for material/debris to accumulate.

ACTION ITEMS

Item	Work Order	Description	Target Date	Person Responsible
1	1249232	Revise the programming of the GF4 Deluge system controller.	**May 15, 2017**	**Phil Winsor / Rick Hibbs**
2	N/A	Full system commissioning on future projects and not allow use of jumpers to verify signals from vital equip. components	**Ongoing**	**Exploits LTAP / PETS**
3	1249215	Test GF9 (Beeton Unit) deluge system during outage to confirm system functionality	**May 1, 2017**	**M. Hutchcraft**
4	1249231	Clean-up of powerhouses, paying close attention to pipe chases and other areas where hidden combustibles may be located.	**May 1, 2017**	**A. Martin**
5	N/A	Review of Hot Work Permits with the crews. Mandatory use of fire blankets around floor openings.	**Ongoing**	**Exploits Maintenance / Contractors**

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HYDRO GENERATION
FORCED OUTAGE REPORT

APPENDIX A:

NL Hydro PETS Report (Internal) - Grand Falls Unit 4 Deluge System Testing

APPENDIX B:

Pennecon Energy Report - Simulating deluge permissive conditions from G4-SEL 300G Relay

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EXPLOITS GENERATION
FORCED OUTAGE REPORT

FORCED OUTAGE DATA:

Unit #:**GF9 (Beeton)**

Start Time & Date	End Date / Time	Duration	Outage / Derating Type	
23:45 on June 12th	16:45 on June 13th	16hr 30m	X	Sudden Forced Outage [i]
				Immediately Deferrable Forced Outage [ii]
				Deferrable Forced Outage [iii]
				Starting –Failure Outage [iv]
				Forced Derating [v]

SUMMARY

Unit GF9 is a Vertical Francis hydroelectric unit with a generator rated output of 33.3MVA. On June 12th at 23:45 the unit tripped on wicket gate response. Unit was in the process of being loaded up from 60% wicket gate position to 80% when the trip occurred. Unit was stalled at 60%.

On-call supervisor was contacted and units GF4 - GF6, and GF8 were loaded up to turbine the water while GF9 was offline.

After the investigation was completed and it was determined that the root cause was friction within the operating ring assembly and not some other underlying issue, unit was placed back in service @ 16:45 on June 13th.

INVESTIGATION

Investigation commenced into the cause of the trip. Electricians inspected and verified the wicket gate position feedback transducer to ensure integrity of signal. PLC programming was reviewed to ensure programming for timing for wicket gate response was appropriate (Governor PLC replaced in 2016). Some minor deficiencies were addressed in the PLC programming, but none of these were responsible for the root cause of the trip.

A trip of this nature has occurred several times over the past 2 years. The OEM (Alstom) has been engaged on separate occasions to assist with trouble-shooting and determine the root cause of this issue. Most recently, the OEM completed an inspection of the operating ring assembly during the PM outage on GF9 in April 2017. During the inspection, a servomotor pin was found broken which required replacement and a single wicket gate was found to require significantly higher torque to operate compared to the remaining wicket gates. These deficiencies were addressed during the outage.

After start-up, testing of the hydraulic forces were completed and results showed that a significant increase in torque was still required to open and close the wicket gates. The corrected deficiencies did not address the true root cause of the issue. The OEM advised in there preliminary inspection report received on June 19th that even though during their testing the unit operated without issue, they anticipated that wicket gate response issues would occur when the net head on the unit increased. The net head on June 12th was approximately 5 feet higher than when testing was performed in April.

The OEM is recommending the replacement of the wicket gate upper and lower bushings to decrease the frictional forces within the operating ring/wicket gate assembly. A substitute bushing material would significantly reduce the frictional forces.

REMEDIAL ACTIONS

Once investigation determined there were no additional causes of the trip with the exception of the frictional forces within the operating ring assembly, unit was placed back in service @ 16:45 on June 13th. To correct the root cause requires advanced planning and procurement of materials, significant downtime, and capital funding.

CONCLUSION

A trip of this nature has occurred several times over the past 2 years. The OEM (Alstom) has been engaged on separate occasions to assist with trouble-shooting and determine the root cause of this issue. Recent inspection and testing completed identifies the most likely cause as frictional forces within the operating ring and wicket gate assemblies.

Recommendations

Complete wicket gate bushing replacement in 2018 Capital program.

ACTION ITEMS

Item	Work Order	Description	Target Date	Person Responsible
1	NA	Develop proposal and cost estimate for the replacement of the wicket gate bushings as part of the 2018 Capital program.	**Aug. 1, 2017**	**P. Winsor**
2	NA	Ensure execution of capital project for replacement of the GF9 wicket gate bushings.	**Dec. 1, 2018**	**P. Winsor**

[i] Sudden Forced Outage: the occurrence of a component failure or other condition which results in the unit being automatically or manually tripped.
[ii] Immediately Deferrable Forced Outage: the occurrence of a component failure or other condition which requires that the unit be removed from service within 10 minutes.
[iii] Deferrable Forced Outage: the occurrence of a component failure or other condition which requires that the unit be removed from service from10 minutes up to and including the very next weekend.
[iv] Starting –Failure Outage: the unsuccessful attempt to bring a unit from a shutdown state to synchronism with the electric system within a specified time interval. The specified time interval may be different for individual units and should allow a reasonable time for the unit to pick up load.
[v] A reduction of generating unit capacity in excess of 2 % of its Maximum Continuous Rating resulting from a component failure or other condition which requires that the generating unit be de-rated at once or as soon as possible up to and including the very next weekend.

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EXPLOITS GENERATION
FORCED OUTAGE REPORT

FORCED OUTAGE DATA:

Unit #: BF2

Start Date and Time	End Date and Time	Duration	Unit Status (Select One)	
Nov 5/17 @ 20:07	December 14/17 @ 15:00	38 days, 19 hrs, 07 mins	√ Forced Trip ☐ Forced Shutdown by Operator	☐ Forced Derating ☐ Start-up ☐ Forced Derating

SUMMARY

On November 5, 2017 unit BF2 experienced a sudden trip on start-up. The trip was initiated by a frequency transducer alarm. On shut-down, the unit would not come to a stop on its own, wicket gates would only close to 5%. Operator intervention was required, and additional force was required using the CMHP manual hand pump and servo to assist in closing gates. Gates were able to be closed to 1.5%, however the unit was still turning over. Mechanical maintenance personnel were called in to lower chamber gates into BF2 due to suspected shearping failure. Upon doing so, the unit came to a complete stop.

INVESTIGATION

Upon entering the center column of the turbine, it was discovered that there was a broken shearpin on gate #15 on the upstream wicket gate assembly. Adjustment to wicket gate turnbuckles was required on gates 14,15,16, and 1. No immediate findings on why the wicket gates would not close completely. Investigation commenced into determining the cause of the wicket gates not closing. The manual hydraulic servo used to provide emergency gate closure was disconnected and pins and bushings inspected to confirm there was no potential binding caused by this equipment. Inspection was completed on the main hydraulic servo during an outage in 2016 and no deficiencies found, so these pins and bushings were not suspect and were not re-inspected. Wicket gate clearances were checked and the end clearances on the wicket gates are very tight. Please see table below.

Design clearances for these wicket gates is 0.020".

In consultation with the OEM, it was recommended to attempt to clean the end seal surfaces of the turbine to improve the tight clearances. An angle grinder equipped with an 80 grit flap disc was used. Significant improvements were made to the end clearances as can be seen in the table below.

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**EXPLOITS GENERATION
FORCED OUTAGE REPORT**

Upstream Assembly						
Wicket Gate	Readings Prior to Cleaning		Readings After Cleaning		**% Improvement**	
	U/S clearance	D/S clearance	U/S clearance	D/S clearance	**U/S clearance**	**D/S clearance**
1	0.006	0.003	0.011	0.005	**83%**	**67%**
2	0.005	0.004	0.004	0.004	**-20%**	**0%**
3	0.003	0.005	0.004	0.013	**33%**	**160%**
4	0.003	0.003	0.005	0.010	**67%**	**233%**
5	0.003	0.006	0.004	0.015	**33%**	**150%**
6	0.003	0.003	0.005	0.005	**67%**	**67%**
7	0.006	0.003	0.005	0.007	**-17%**	**133%**
8	0.007	0.002	0.010	0.005	**43%**	**150%**
9	0.006	0.002	0.009	0.004	**50%**	**100%**
10	0.007	0.002	0.010	0.004	**43%**	**100%**
11	0.004	0.002	0.010	0.003	**150%**	**50%**
12	0.005	0.002	0.010	0.003	**100%**	**50%**
13	0.005	0.003	0.010	0.010	**100%**	**233%**
14	0.003	0.002	0.009	0.004	**200%**	**100%**
15	0.009	0.002	0.003	0.002	**-67%**	**0%**
16	0.009	0.002	0.005	0.003	**-44%**	**50%**

Downstream Assembly						
Wicket Gate	Readings Prior to Cleaning		Readings After Cleaning		**% Improvement**	
	U/S clearance	D/S clearance	U/S clearance	D/S clearance	**U/S clearance**	**D/S clearance**
1	0.006	0.003	0.005	0.012	**-17%**	**300%**
2	0.005	0.004	0.003	0.015	**-40%**	**275%**
3	0.003	0.005	0.015	0.013	**400%**	**160%**
4	0.003	0.003	0.015	0.010	**400%**	**233%**
5	0.003	0.006	0.007	0.012	**133%**	**100%**
6	0.003	0.003	0.015	0.010	**400%**	**233%**
7	0.006	0.003	0.002	0.015	**-67%**	**400%**
8	0.007	0.002	0.004	0.015	**-43%**	**650%**
9	0.006	0.002	0.003	0.015	**-50%**	**650%**
10	0.007	0.002	0.010	0.003	**43%**	**50%**
11	0.004	0.002	0.010	0.015	**150%**	**650%**
12	0.005	0.002	0.010	0.015	**100%**	**650%**
13	0.005	0.003	0.010	0.007	**100%**	**133%**
14	0.003	0.002	0.010	0.013	**233%**	**550%**
15	0.009	0.002	0.008	0.015	**-11%**	**650%**
16	0.009	0.002	0.013	0.008	**44%**	**300%**

Note: Readings highlighted in red have been flagged as the clearance readings are lower after cleaning. Likely due to a difference in the location along the gates where readings were taken.

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**EXPLOITS GENERATION
FORCED OUTAGE REPORT**

REMEDIAL ACTIONS

The OEM, American Hydro, has previously provided a proposal to complete a Turbine inspection on the BF2 unit. This has been put forward as an operating project for 2018. This detailed inspection will confirm the root cause of the issue is the reduced end seal clearances.

CONCLUSION

The reduced end seal clearances on the wicket gates due to buildup of dirt/sediment has increased hydraulic forces required to close the wicket gates on BF unit 2. Cleaning of the surfaces has improved the condition in the short term, however this condition is likely to re-occur again in time.

RECOMMENDATIONS

- Engage American Hydro to determine a long term fix.
- Continue to monitor BF1-6 for similar conditions and clean surfaces of units as these conditions present themselves.

ACTION ITEMS

Item	Work Order	Description	Target Date	Person Responsible
1		Engage American Hydro to determine a long term fix for maintaining wicket gate end seal clearances. Develop plan based on recommendations.	**Dec. 1, 2018**	**P. Winsor**
2	NA	Continue to monitor BF1-6 for similar reductions in end seal clearances and clean surfaces of units as these conditions present themselves.	**Ongoing**	**A. Martin**

American Hydro
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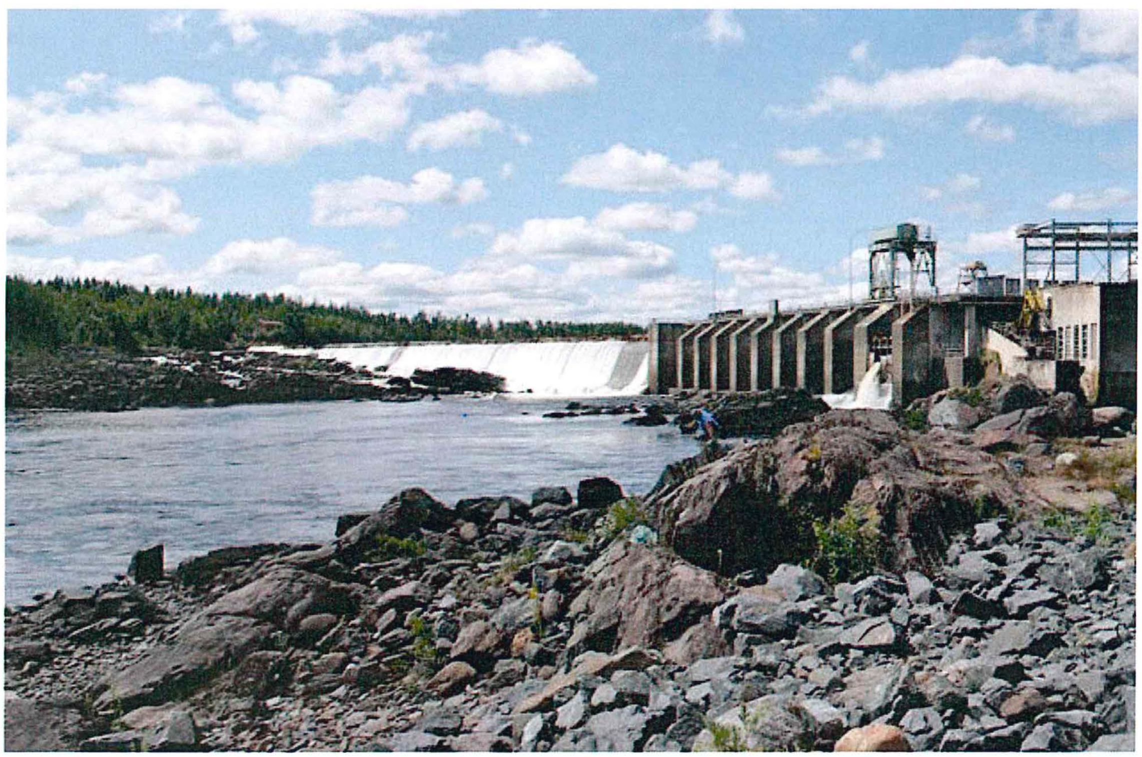
Bishop's Falls Unit 2 Seagull Turbine Field Engineering Survey

Newfoundland & Labrador Hydro
Exploits Generation Division

34859-TD Rev -
August 31, 2018

American Hydro Contract No. 64070



Mike Little
Supervisor of CAD Design

Introduction

American Hydro supplied (6) identical Seagull hydro turbine units for the Bishop's Falls plant. These units were installed and then commissioned in 2003. Recently U2 began to have trouble closing the wicket gates as designed. Based on this observation Newfoundland & Labrador Hydro contracted Wartsila Canada, Inc to observe the unit in operation and perform a dewatered inspection. Wartsila Canada, Inc subcontracted this work to American Hydro.

American Hydro sent Field Service Technician Tom Black to the site to perform this work. He observed U2's operational characteristics the week of August 13, 2018 and entered the unit for inspection the week of August 20, 2018. Tom was the fabrication and assembly shop foreman when these units were built in our York, PA facility.

Included in this report are the check sheets from the inspection, notes related to the observed operational characteristics and our theory concerning the cause of the degraded performance.

Observed Operational Characteristics

During a run with no load the unit was at 90% gate and running at 277 rpm. When the gates were closed they stopped at 1% open and needed assistance from the manual hydraulic system. It took an additional 500 psi on the hand pump to close the gates completely. Prior to the manual pump assistance, the unit would only slow to a speed of 63 rpm.

During a run under load the unit was at 90% gate and running at 277 rpm. When the gates were closed they stopped at 2% open and needed assistance from the manual hydraulic system. It took an additional 700 psi on the hand pump to close the gates completely. Prior to the manual pump assistance, the unit would only slow to a speed of 74 rpm.

The disc braking system it set to automatically engage at 58 rpm. Neither test run dropped the rpm sufficiently to allow the disc brake to energize.

The HPU supplying the U2 servo was observed to be operating at 1000 to 1200 psi during each test. Units 1, 2 and 3 share a common HPU. Units 4, 5, 6 and 7 share a second HPU.

Interpretation of the check sheets

Please find the check sheet package in Appendix A of this report.

Distributor Clearances U2 Upstream –

Design wicket gate end seal clearance is .019” each end. Note that the end seal clearance of .000” is consistent for all 16 wicket gates.

Distributor Clearances U2 Downstream –

Design wicket gate end seal clearance is .019” each end. Note that the end seal clearance varies from .000” to .021”. The average nose end clearance is .006”, the average tail end clearance is .013”.

Based on the design value of .019” each end, the as found clearances on both distributors are too tight for proper operation. In the photos below please note the buildup of scale on the wicket gate interface surfaces.

Gate Ring Clearances U2 Upstream & U2 Downstream –

Readings 1-4 were taken at the flat pads under the gate ring. Readings 5-8 were taken at the arched pads. Readings 9-12 were taken under the bolt on retainer clips. Design diametrical clearance of the arched pads is .010"/.030".

Note that measurements 5-8 on both distributors are .000". Based on the design value of .010"/.030" diametrical clearance, the as found clearances on both distributors are too tight for proper operation.

Wicket Gate Bushing Wear U2 Upstream -

Design bushing clearance is .005"/.010" diametrical.

Gate #1 - .002" (snug)
Gate #5 - .005"
Gate #9 - .006"
Gate # 14 - .006"

Wicket Gate Bushing Wear U2 Downstream -

Design bushing clearance is .005"/.010" diametrical.

Gate #1 - .007"
Gate #5 - .005"
Gate #9 - .003" (snug)
Gate # 14 - .011"

All clearances appear to be acceptable. No excessive wear or binding is noted. As a further check a turnbuckle was disconnected from a wicket gate and the gate operated freely by hand.

Seagull Dual Bearing Clearances -

While not a cause of the shutdown issues, the main bearing clearances were inspected as a courtesy.

Design diametrical clearance is .017"

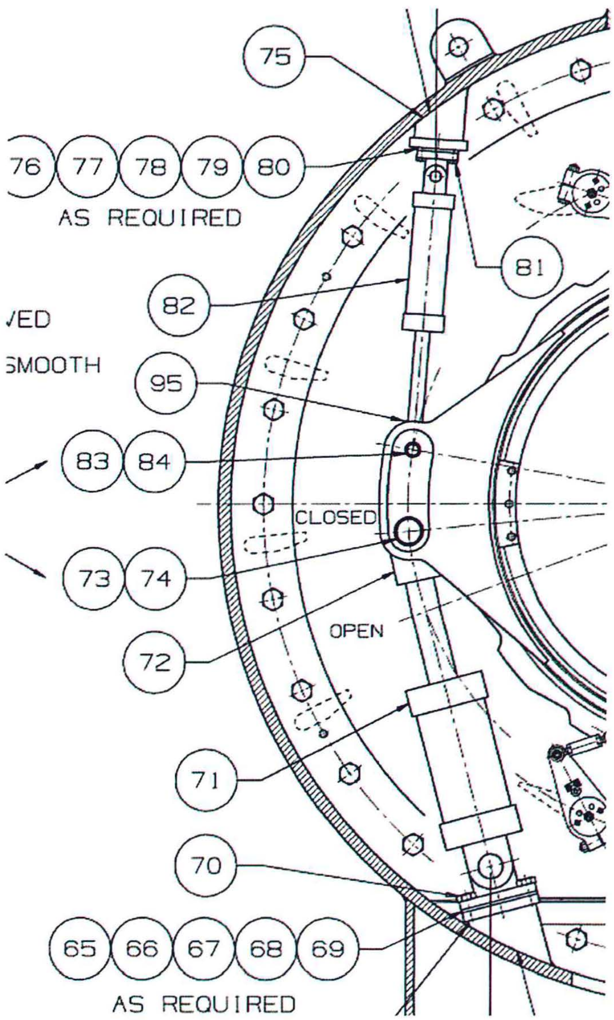
U2 Upstream - .016" vertical, .013" horizontal
U2 Downstream - .023" vertical, .013" horizontal

Both main bearing clearances are acceptable.

Servomotor Pivot Bushings –

Personnel assisting our technician mentioned that the servomotor pivot bushing clearances are extremely tight. Balloon numbers (73) and (83) point to these connections. These bushings should have .002"/.007" diametrical clearance.

While we were unable to measure the servomotor pivot bushing clearances it is anticipated that they may be too tight for proper operation.



Recommendations to improve unit operation -

After reviewing the inspection results American Hydro has developed (3) distinct recommendations to restore the desired operating characteristics of U2. Based on our observations and measurements it is our theory that excessive friction is driving the need for additional operational force.

While not common, we have seen ORKOT bushings and pads swell even though they are not immersed in water. The Seagull center support column approaches 100% humidity and it is surmised that this condition provides enough moisture for the ORKOT material to absorb and swell.

Our first recommendation is to design a fixture that enables the servomotor pins to be removed from the gate ring bushings and the servomotor clevis. Once the servomotor pins are removed the bushing bores would be honed to the high side of the OEM .002"/.007" diametrical clearance.

Our second recommendation addresses the undesirable line to line fit of the gate ring ID to the stationary wear pads. While the servomotors are disconnected, one gate ring at a time would be slid horizontally towards the center of the support column. Once the stationary arched wear pads are exposed they would be hand sanded to reduce their thickness. During this process the gate ring would be slid back over the pads and the clearances would be checked several times. Once a diametrical clearance of .020" to .030" is achieved the gate ring retainer clips would be re-installed.

Our third and final recommendation focusses on the scale buildup on the wicket gate interface surfaces. Our technician disconnected one wicket gate turnbuckle and was able to rotate the wicket gate nearly 360 degrees. This range of movement allows power tool access to buff the buildup of scale from these surfaces. American Hydro has experience with several abrasive wheels, discs and tools to do this work without undermining the base metal. Ideally, the scale removal process would provide the OEM .019" clearance on each end of the wicket gate. However, .010" clearance on each end would be acceptable.

Once the excessive friction generated in these three areas is mitigated we would expect that the machine will return to its desired operating scheme.

Please contact us should you have any questions or need clarification on this report. American Hydro would be pleased to provide a proposal for this work should you elect to proceed with our recommendations.

APPENDIX A – CHECK SHEETS

American Hydro
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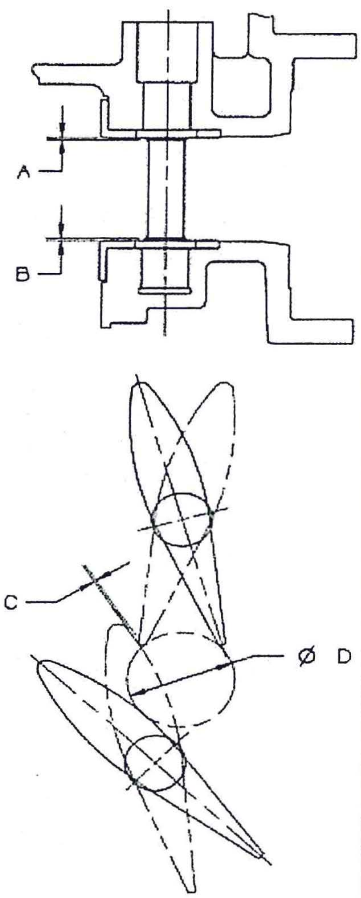
INSPECTION RECORD SHEET

DISTRIBUTOR CLEARANCES

Document No.
Project No.
Project Name Bishop Falls
Unit No. U2 U.S.



	Dimension					
	A		B		C Vertical Seal	D 100% Open
Gate	Nose	Tail	Nose	Tail		
1	.000			.000	.002	8 1/2
2					.001	8 23/32
3					.000	8 7/16
4					.000	8 25/32
5					.005	8 13/32
6					.007	8 23/32
7					.002	8 17/32
8					.000	8 1/2
9					.003	8 23/32
10					.003	8 13/32
11					.000	8 23/32
12					.0015	8 1/2
13					.003	8 23/32
14					.065	8 9/32
15					.030	8 23/23
16	.000			.000	.025	8 3/4
17						
18						
19						
20						
21						
22						
23						
24						
25						
26						

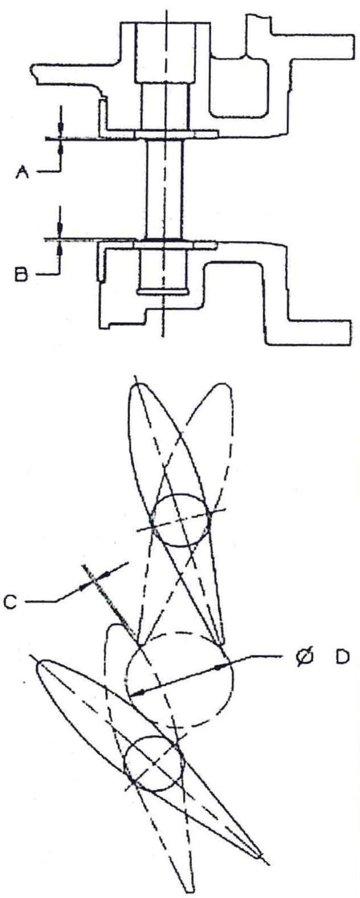
Check One: Pre-Teardown ☐ Installation ☐ Shop ☐

Measurement Instrument

Temperature
Before: ________
After: ________

Measured By: ____________
AHC Representative: ____________
Cust. Representative: ____________
Date: ____________

American Hydro A Wärtsilä Company WÄRTSILÄ	INSPECTION RECORD SHEET	Document No. Project No.
	DISTRIBUTOR CLEARANCES	Project Name Bishop Falls Unit No. 2 D.S.



	Dimension						
	A		B		C Vertical Seal	D 100% Open	
Gate	Nose	Tail	Nose	Tail			
1	.005			.011	.003-4"		8 7/16
2	.000			.010	.000		8 11/16
3	.010			.014	.003-4"		8 7/16
4	.016			.009	.000		8 7/16
5	.006			.010	.000		8 11/16
6	.008			.009	.004		8 7/16
7	.000			.012	.000		8 5/16
8	.000			.014	.000		8 3/8
9	.000			.021	.005 –	.000 - 2"	8 5/8
10	.005			.013	.000		8 11/16
11	.000			.020	.003 - 10"		8 7/16
12	.003			.016	.004 –	.003 = 1/24 1/2	8 1/2
13	.011			.012	.000		8 11/16
14	.012			.011	.000		8 7/16
15	.006			.018	.015-8"	.011 - Remaining	8 5/8
16	.009			.009	.003 - 2"		8 5/8
17							
18							
19							
20				.013			
21	.006			AVG.			
22	AVG.						
23							
24							
25							
26							

Check One: Pre-Teardown ☐ Installation ☐ Shop ☐

Measured By: ______________

Measurement Instrument	Temperature	
______________	*Before:* ________	AHC Representative: ______________
______________	*After:* ________	Cust. Representative: ______________
		Date: ______________

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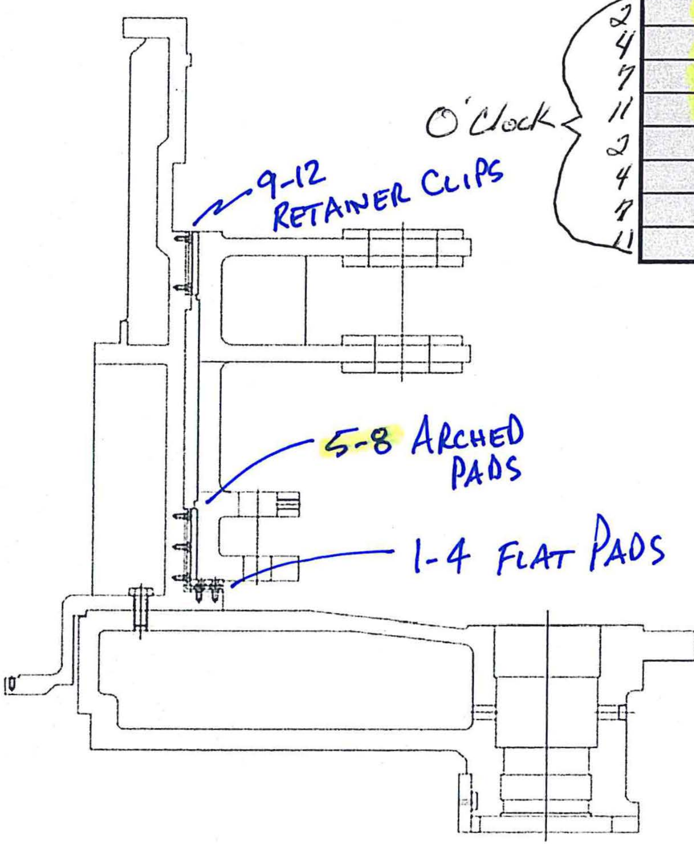
INSPECTION RECORD SHEET

GATE RING CLEARANCE

Document No.
Project No.
Project Name Bishop Falls
Unit No. 2 U.S.

O'Clock

	Location	Clearance
Top	1	.006
Left	2	.0015
Right	3	.008
Bottom	4	.014
2	5	.000
4	6	.000
7	7	.000
11	8	.000
2	9	.006
4	10	.0015
7	11	N/A
11	12	.008



Check One: Pre-Teardown ☐ Installation ☐ Shop ☐

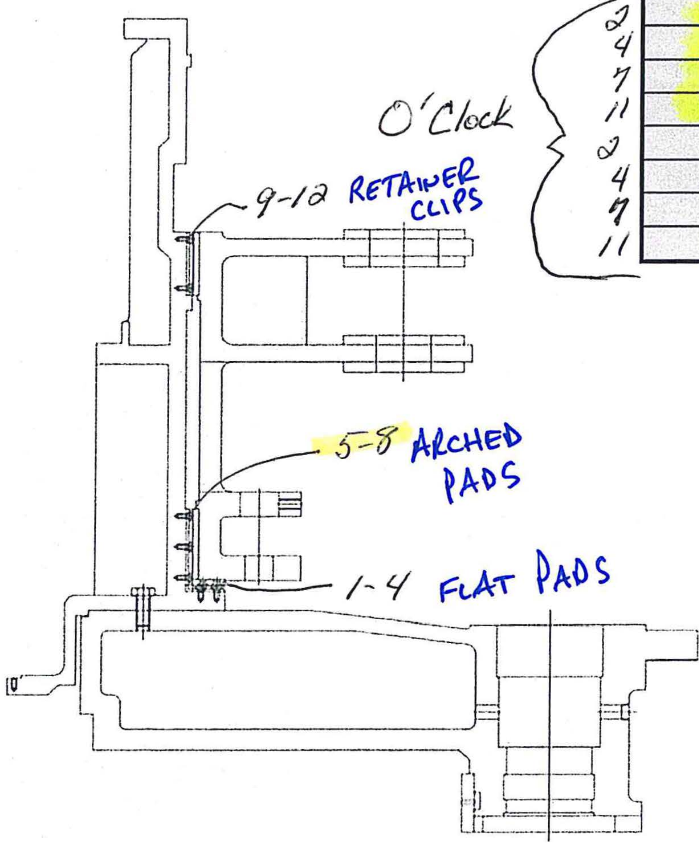
Measured By: ______

Measurement Instrument	Temperature
______	*Before:* ______
______	*After:* ______

AHC Representative: ______
Cust. Representative: ______
Date: ______

American Hydro A Wärtsilä Company WÄRTSILÄ	INSPECTION RECORD SHEET GATE RING CLEARANCE	Document No. Project No. Project Name Bishop Falls Unit No. 2 D.G.

	Location	Clearance
Top	1	.008
Left	2	.002
Right	3	.005
Bottom	4	.018
O'Clock 2	5	.000
4	6	.000
7	7	.000
11	8	.000
2	9	.000
4	10	N/A
7	11	.000
11	12	.008



Check One: Pre-Teardown ☐ Installation ☐ Shop ☐	Measured By:
Measurement Instrument / Temperature	AHC Representative:
Before:	Cust. Representative:
After:	Date:

Wicket Gate Bushing Wear Checking Procedure

X1	,001	
X2	,000	
XFIM	X1+X2	
Y1	,002	
Y2	,000	
YFIM	Y1+Y2	
FIM	Maximum of XFIM and YFIM	.002"

Gate # - 1 US

X1	,005	
X2	,000	
XFIM	X1+X2	
Y1	,004	
Y2	,060	
YFIM	Y1+Y2	
FIM	Maximum of XFIM and YFIM	.005"

Gate # - 5 US

X1	,002	
X2	,000	
XFIM	X1+X2	
Y1	,005	
Y2	,001	
YFIM	Y1+Y2	
FIM	Maximum of XFIM and YFIM	.006"

Gate # - 9 US

X1	,006	
X2	,000	
XFIM	X1+X2	
Y1	,006	
Y2	,000	
YFIM	Y1+Y2	
FIM	Maximum of XFIM and YFIM	.006"

Gate # - 14 US

Wicket Gate Bushing Wear Checking Procedure

X1	,006	
X2	,001	
XFIM	X1+X2	
Y1	,006	
Y2	,000	
YFIM	Y1+Y2	
FIM	Maximum of XFIM and YFIM	.007"

Gate # - 1 DS

X1	,002	
X2	,000	
XFIM	X1+X2	
Y1	,004	
Y2	,001	
YFIM	Y1+Y2	
FIM	Maximum of XFIM and YFIM	.005"

Gate # - 5 DS

X1	,002	
X2	,000	
XFIM	X1+X2	
Y1	,003	
Y2	,000	
YFIM	Y1+Y2	
FIM	Maximum of XFIM and YFIM	,003"

Gate # - 9 DS

X1	,009	
X2	,002	
XFIM	X1+X2	
Y1	,005	
Y2	,000	
YFIM	Y1+Y2	
FIM	Maximum of XFIM and YFIM	,011"

Gate # - 14 DS

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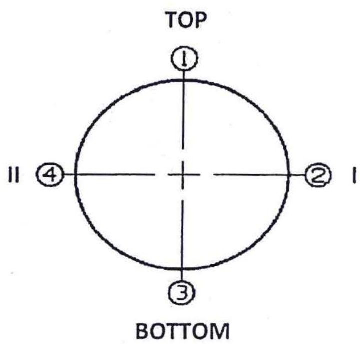
INSPECTION RECORD SHEET

SEAGULL DUAL BEARING CLEARANCES

Document No.
Project No.
Project Name Bishop Falls
Unit No. 2 Up Stream



	0° Rotation			
BRG	1	2	3	4
US	.016	.007	.000	.006
DS	—	—	—	—

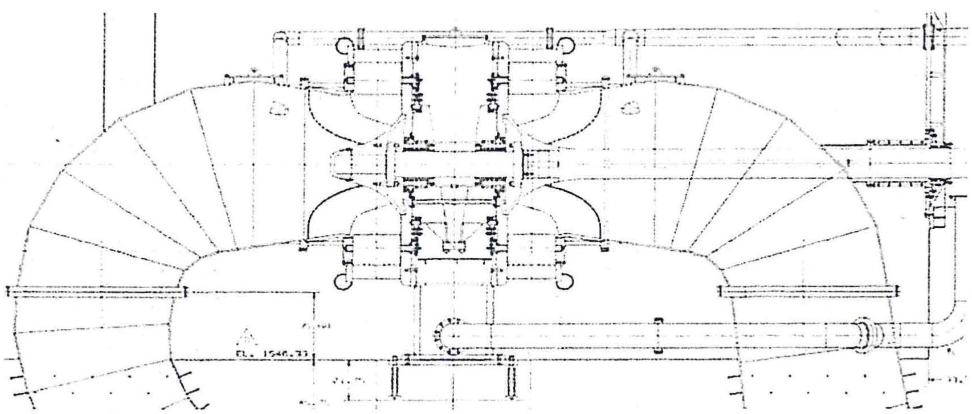
	0° Total Clearance	
BRG	1-3	2-4
UGB	0.0000	0.0000
LGB	0.0000	0.0000

Notes:

	90° Rotation			
BRG	1	2	3	4
US				
DS				

	0° Total Clearance	
BRG	1-3	2-4
UGB	0.0000	0.0000
LGB	0.0000	0.0000

US



DS

Check One: Pre-Teardown ☐ Installation ☐ Shop ☐

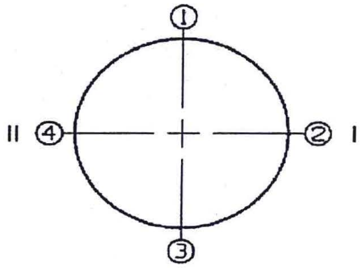
Measured By: ____________

Measurement Instrument ____________ ____________

Temperature Before: ______ After: ______

AHC Representative: ____________
Cust. Representative: ____________
Date: ____________

American Hydro A Wärtsilä Company WÄRTSILÄ	INSPECTION RECORD SHEET	Document No.
		Project No.
	SEAGULL DUAL BEARING CLEARANCES	Project Name Bishop Falls
		Unit No. 2 Down Stream



	0° Rotation			
BRG	1	2	3	4
US	—	—	—	—
DS	.023	.007	.000	.006

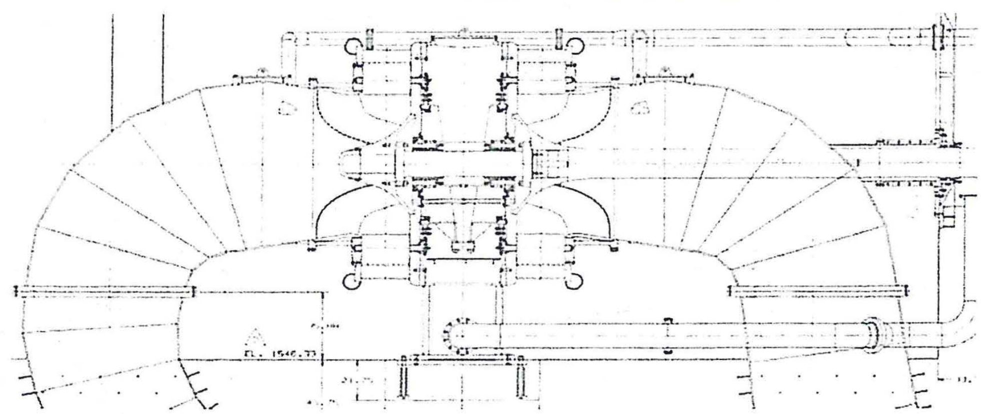
	0° Total Clearance	
BRG	1-3	2-4
UGB	0.0000	0.0000
LGB	0.0000	0.0000

Notes:

	90° Rotation			
BRG	1	2	3	4
US				
DS				

	0° Total Clearance	
BRG	1-3	2-4
UGB	0.0000	0.0000
LGB	0.0000	0.0000

US



DS

Check One: Pre-Teardown ☐ Installation ☐ Shop ☐

Measurement Instrument ________________

Temperature
Before: ________
After: ________

Measured By: ________________
AHC Representative: ________________
Cust. Representative: ________________
Date: ________________

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EXPLOITS GENERATION
FORCED OUTAGE REPORT

FORCED OUTAGE DATA:

Unit #: BF5

Start Time & Date	End Date / Time	Duration	Outage / Derating Type	
06:43 01-15-18	07:29 01-15-18		X	Sudden Forced Outage [1]
				Immediately Deferrable Forced Outage [2]
				Deferrable Forced Outage [3]
				Starting –Failure Outage [4]
				Forced Derating [5]

SUMMARY

BF5 tripped on loss of shaft seal cooling water flow. Operator cleared alarms, adjusted shaft seal cooling water flow and put the unit back online.

INVESTIGATION

There have been three trips, including this one, recently on Unit BF5 for loss of shaft seal cooling water flow and loss of turbine bearing cooling water flow. We have a known issue with corrosion build-up and loss of flow capacity in the cooling water piping at BF Plant. In normal operation, with full piping flow capacity, we run one of two cooling water pumps to supply cooling water through a filtration system to the generating units. At present we find it necessary to run two cooling water pumps in order to maintain sufficient flow through the filter backflush cycles. Cooling Water Pump #1 had been taken off due to an issue with the pump/motor coupling jacket leaving us with one pump running. As mentioned above, corrosion build-up has reduced the operating capacity of the BF Plant cooling water system such that with one pump running we are at risk of unit trips when the cooling water filtration system goes into regular backflush. Trips for loss of cooling water flow are initiated by contacts in the flowmeters on the shaft seal and turbine bearing cooling lines for each unit. The flowmeters on BF5's cooling skid seem to be more susceptible to triggering trips on loss of flow during one-pump operation than those on the other Bishop's Falls generating units. The fact that we see trips triggered by both the shaft seal and turbine bearing flowmeters on BF5 would indicate restriction in the piping upstream of the flowmeters.

---

[1] Sudden Forced Outage: the occurrence of a component failure or other condition which results in the unit being automatically or manually tripped.
[2] Immediately Deferrable Forced Outage: the occurrence of a component failure or other condition which requires that the unit be removed from service within 10 minutes.
[3] Deferrable Forced Outage: the occurrence of a component failure or other condition which requires that the unit be removed from service from10 minutes up to and including the very next weekend.
[4] Starting –Failure Outage: the unsuccessful attempt to bring a unit from a shutdown state to synchronism with the electric system within a specified time interval. The specified time interval may be different for individual units and should allow a reasonable time for the unit to pick up load.
[5] A reduction of generating unit capacity in excess of 2 % of its Maximum Continuous Rating resulting from a component failure or other condition which requires that the generating unit be de-rated at once or as soon as possible up to and including the very next weekend.

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**EXPLOITS GENERATION
FORCED OUTAGE REPORT**

REMEDIAL ACTIONS

Cooling Water Pump 1 has been repaired and put back in service. To date, since we have been running two cooling water pumps in BF Plant, there has not been another unit trip for loss of cooling water.

CONCLUSION

Plans are in place to change out the cooling water system piping at Bishop's Falls Plant later this year. When this work is completed we should be able to return to one-pump operation at the plant with sufficient cooling water pressure/flow being maintained during normal river conditions.

Recommendations

- Until work has been completed to replace the cooling water system piping at BF Plant, both cooling water pumps should be kept in operation.
- Investigate feasibility of taking BF5 bearing oil pump out of service – this would reduce cooling water demand on that unit

Action Items

ACTION ITEMS

Item	Work Order	Description	Target Date	Person Responsible
1	XXXXXX			
2	XXXXXX			
3	XXXXXX			

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EXPLOITS GENERATION
FORCED OUTAGE REPORT

4	XXXXXX			

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EXPLOITS GENERATION
FORCED OUTAGE REPORT

FORCED OUTAGE DATA:

Unit #:BF4

Start Time & Date	End Date / Time	Duration	Outage / Derating Type	
November 16, 2018	November 25, 2018	**9 days total**	X	Sudden Forced Outage [1]
				Immediately Deferrable Forced Outage [2]
				Deferrable Forced Outage [3]
				Starting –Failure Outage [4]
				Forced Derating [5]

SUMMARY

During start-up of BF1 and BF2 after planned work on those units, BF4 tripped when BF1 went online. A subsequent re-start resulted in a trip, related to a field issue. It was decided that there was a requirement for intervention to determine to source of the issue

INVESTIGATION:

Friday, Nov. 16: After the start-up of BF1, on Friday evening, BF4 tripped. The Micom protective relay indicated “1GT ¾ Trip” and a “Field Fault Trip”. (As a side note, a tree fell on the transmission line Thursday, Nov. 15, and caused a full plant outage)
BF4 was again tried after it tripped with no luck and then tried the second time Friday night, it was then left offline. Again, the Micom protective relay indicated “1GT ¾ Trip” and a “Field Fault Trip”.

Saturday, Nov. 17: No work on BF4 on Saturday.

Sunday, Nov. 18: An electrician was called to try to troubleshoot issue with BF4 and Elmo Hibbs was contacted for assistance. The unit was tried two more times with no luck. Same trip alarms in the Micom relay.

[1] Sudden Forced Outage: the occurrence of a component failure or other condition which results in the unit being automatically or manually tripped.
[2] Immediately Deferrable Forced Outage: the occurrence of a component failure or other condition which requires that the unit be removed from service within 10 minutes.
[3] Deferrable Forced Outage: the occurrence of a component failure or other condition which requires that the unit be removed from service from10 minutes up to and including the very next weekend.
[4] Starting –Failure Outage: the unsuccessful attempt to bring a unit from a shutdown state to synchronism with the electric system within a specified time interval. The specified time interval may be different for individual units and should allow a reasonable time for the unit to pick up load.
[5] A reduction of generating unit capacity in excess of 2 % of its Maximum Continuous Rating resulting from a component failure or other condition which requires that the generating unit be de-rated at once or as soon as possible up to and including the very next weekend.

EXPLOITS GENERATION
FORCED OUTAGE REPORT

INVESTIGATION (cont'd):

Monday, Nov. 19: The electricians were in to conduct a Meggar test on the rotor: result was 8 GΩ, which indicated healthy rotor insulation. They also began checking the voltage control signal from the BF4 switchgear and PLC and then to the Exciter cubicle. It was confirmed this was functioning as it should. In addition, the interposing relays within the Exciter control and Synchronization circuits were checked, and deemed to be working as they should.

Tuesday Nov. 20: Checked the rotor with an ohmmeter to verify that the winding continuity was good and the resistance was the expected value of approximately 0.9 Ω. This was good. Again troubleshooting the Exciter for possible issues and communication between the PLC and the Exciter chassis (had assistance from Elmo Hibbs). The Basler RA-70 reference adjuster was taken from BF6, and installed into BF4. The unit was started up and tripped again. The Micom relay indicated a "Field Fault Trip".

Wednesday, Nov. 21: Tried starting the unit in full manual mode. The unit started successfully and synchronized. It stayed online for about 2 hours, until BF1 was started. BF4 then tripped again. The Micom relay indicated a "Field Fault Trip".
Again, troubleshooting the Exciter and any possible connection to the Auto-Sync PLC control circuits, that may be an issue.
(As a side note, there was a HPU#1 PM completed that day not directly effecting BF4 but it was ongoing with a minor oil spill)

Thursday, Nov. 22: Very limited to troubleshooting as there was a HPU#2 PM going on this day which prevented any attempts to start BF4 unit, however, there were some checks completed later upon start up. It was attempted to start BF4 in full manual mode, with no success. BF4 tripped, again with the Micom relay indicating a "Field Fault Trip".

Friday, Nov. 23: Spent the day studying more drawings and narrowing down possible problems, made a list of things to try and went to plant to try them.

Saturday, Nov. 24: Verified the proper operation of the K1 (field flashing release) relay, as well as the pre-position release function in the Basler RA-70. After adjusting some PC board-mounted Exciter potentiometers related to stability and reaction time adjustment of the AVR circuit, we tried to start the unit in full manual mode. This proved unsuccessful. The unit tripped again and the Micom relay again indicated a "Field Fault Trip".

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EXPLOITS GENERATION
FORCED OUTAGE REPORT

REMEDIAL ACTIONS

The decision was made to remove the complete Exciter electronics chassis (containing the AVR board, SCR Firing board, and sensing circuits) from BF6 Exciter enclosure and install it in BF4 Exciter enclosure. As the work was being completed, the entire BF plant was shut due to frazil ice.

On Sunday, Nov. 25, BF4 unit was started when the rest of the plant was put online. Start-up was successful. The issue was resolved.

CONCLUSION

The issue of BF4 not being able to synchronize in "Auto", and even later in full manual mode was believed to be an issue relating only to the Excitation control in BF4 itself. The Micom relay trip descriptions, "1GT ¾ Trip" and a "Field Fault Trip" clearly indicated an issue with VAR control on the stator, which is in turn is controlled by the excitation on the unit's rotor. However, when BF1 would go online (with BF4 running) it would cause BF4 to trip, further complicating the rationale behind thinking there was only an isolated problem with BF4, and introduced the possibility of a relational issue between BF1 and BF4. This considerably widened the scope of possible malfunction.

The troubleshooting process involved isolating portions of the controls, including synchronization circuits and related equipment, as well and conducting tests on various parts of the complete Excitation system and its peripheral pieces. This involved personnel and specialists. (Some of whom have had many years' experience with these units and the integrated equipment)

The fact that BF4 would start up in Manual mode and respond to voltage raise/lower commands from the operator, as well synchronize (meaning that the voltage control circuits were functional, at least to the point of voltage-matching the generator to the incoming bus, did complicate the approach to resolving the issue. However, using a step-by-step approach, it was decided, after much testing and troubleshooting, that the issue was indeed unrelated to BF1, including any synchronizing controls, and isolated to the BF4 Exciter only.

Upon inspection of the electronics taken out of BF4, it was noticed that there was a portion of the integrated circuit board that appeared burned, with some minor damage. This could not be seen readily from the front whilst it was mounted in the Exciter.

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EXPLOITS GENERATION
FORCED OUTAGE REPORT

Recommendations

Unlike more modern day Excitation equipment, the vintage nature of the electronics in the Exciter units at Bishop's Falls do not readily reveal any fault codes, led alarm indications or visual clues that point to possible sources of problems.
Due to the nature of these units, it would be wise to contact Basler (the manufacturer) in order to get as much information as possible on how to troubleshoot the electronics at the circuit-level in these models, if possible. The large-scale integrated circuit components have several test points (labelled TP1, TP2, etc.) from which voltage/signals may be measured with a meter or oscilloscope to possibly determine if a component is healthy or in need of replacement. In addition, these test points may be of use in tuning the Exciter to maximize stability and response times to ideal values.

Prior to replacing the electronics in the BF6 Exciter, it is recommended to have the faulty circuit board replaced/repaired and tested, either by Basler or by someone using an approved methodology by the manufacturer.

Action Items

1. Have the defective electronics board replaced/repaired and tested
2. Get more detailed information on the Exciter tuning and troubleshooting faults
3. Ensure that we have a known, good swappable spare.

ACTION ITEMS

Item	Work Order	Description	Target Date	Person Responsible
1		Repair/replace Exciter board	**Dec. 31, 2018**	**D.Cole**
2		Get more information from Basler on Exciter troubleshooting	**Dec.31, 2018**	**D.Cole**
3		Ensure that we have a known, good swappable spare	**Dec. 31, 2018**	**D.Cole**
4				

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June 29, 2017

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: Holyrood Unit 2 Fire Damage Restoration
Allowance for Unforeseen Items – Final Report

Please find enclosed the original and twelve copies of the final report in relation to the above-noted matter.

Should you have any questions, please contact the undersigned.

Yours truly,

NEWFOUNDLAND AND LABRADOR HYDRO

Michael Ladha
Legal Counsel & Assistant Corporate Secretary

ML/bs

Unit 2 Fire Damage and Rehabilitation

Holyrood Thermal Generating Station

June 2017

A Report to the Board of Commissioners of Public Utilities

newfoundland labrador hydro
a nalcor energy company

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2. Unit 2 Boiler Combustion System – Description and Layout 1
3. Project Description 3
4. Project Justification 4
5. Project Cost 5
6. Future Plans 5
7. Conclusion 6

Appendix A – Unit 2 Fire Damage Photos

1.0 Introduction

Newfoundland and Labrador Hydro (Hydro) owns and operates the Holyrood Thermal Generating Station (Holyrood), which has a generating capacity of 490 MW. Holyrood is an essential part of the Island Interconnected System.

Holyrood is composed of three thermal generating units along with sub-systems that are vital to its daily operation. In this report, Hydro details the expenditure associated with the use of the Allowance for Unforeseen Items account for the rehabilitation of Unit 2 following the fire and damage that occurred in May 2017.

2.0 Unit 2 Boiler Combustion System – Description and Layout

The four main components of a thermal generating unit are:

1. Boiler;
2. Steam Turbine;
3. Generator; and
4. Transformer.

In the boiler, the main components of the combustion system are:

1. Forced draft fans;
2. Combustion air ductwork;
3. Ignitor air fan;
4. Fuel oil system;
5. Light oil burner guns;
6. Heavy oil burner guns;
7. Flue gas ductwork; and
8. Exhaust stack.

This project involved the Unit 2 boiler combustion system. The purpose of the boiler combustion system is to deliver combustion air and fuel to the boiler to produce steam.

For combustion of No.6 fuel oil in the boiler, there are twelve (12) burners in total arranged at three (3) different elevations on the boiler with four (4) burners per elevation. The burners at each elevation are located at the four (4) corners of the furnace and are labelled A, B, C and D Corners. Combustion of No.6 fuel oil requires a supply of combustion air which is provided to the burners by two (2) forced draft fans and ductwork. During the initial boiler start-up, a smaller pilot flame is used to light-off each No.6 fuel oil burner. Each burner has an ignitor that provides the pilot flame to light-off the burner. The ignitors burn diesel fuel and are ignited using a spark plug. The ignitors have a dedicated combustion air system. The system includes an in-line ignitor air fan which takes air from the forced draft fan ductwork and discharges it into the boiler at the twelve (12) burner gun locations. The ignitor air ductwork consists of ten (10) inch steel ducting that contains flexible expansion joints that enable thermal expansion and movement during operation. The typical burner gun arrangement on a corner fired boiler is shown in Figure 1.

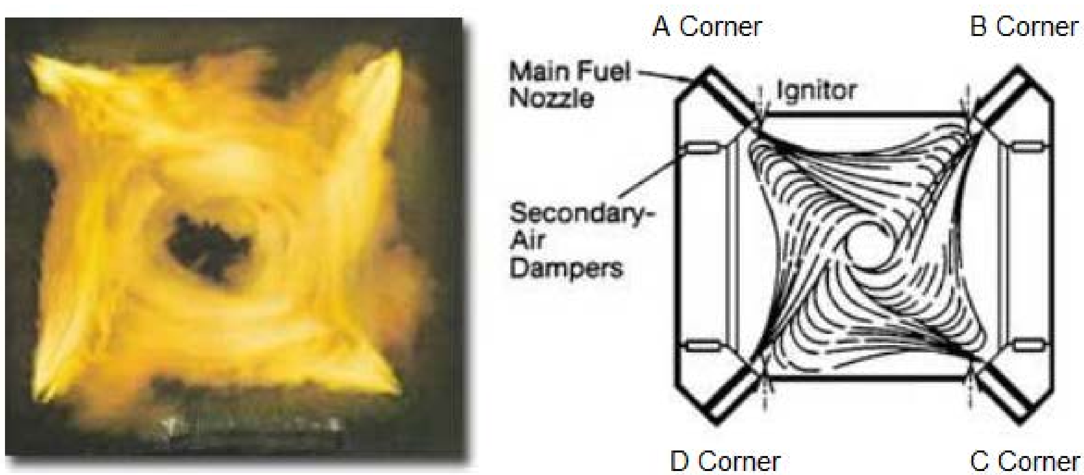

Figure 1 – Corner Fired Boiler

The Unit 2 ignitor air system ductwork is shown in Figure 2.

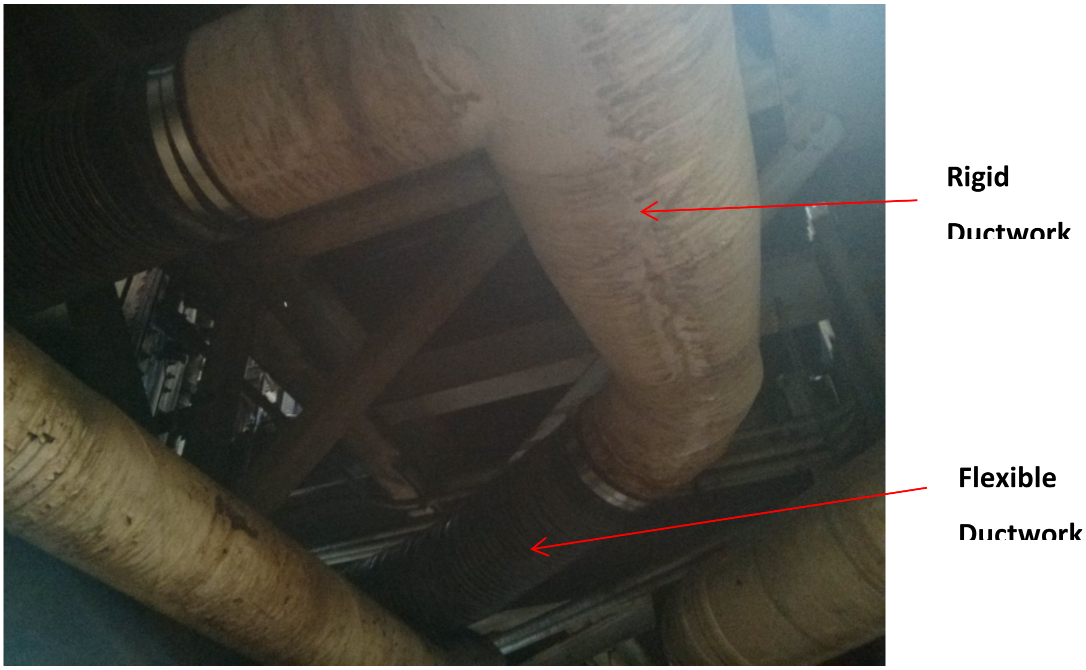

Figure 2 – Ignitor Air System Ductwork

3.0 Project Description

This project involved the sectional replacement of electrical, instrumentation, and controls cables and the replacement of a motor control center starter serving Unit 2 boiler that was damaged as a result of a fire that occurred in May 2017.

On Monday, May 1, 2017, a fire occurred on the Northeast corner of the Unit 2 boiler on the second floor of the Holyrood Thermal Generating Plant. The fire was the result of a failure of a metal hose clamp on the flexible duct on the boiler ignitor air system, which allowed pressurized hot flue gas from the boiler to enter the powerhouse and affect nearby equipment. The hot flue gas caused a fire in two (2) cable trays adjacent to the duct failure location, forcing a unit trip and plant evacuation. The fire was extinguished and an initial assessment determined that several electrical conduits were directly exposed to the fire, which resulted in damage to power, control, and instrumentation cables. The presence of asbestos meant that a detailed assessment was not immediately possible.

Immediately following the fire, site preparation work, including extensive asbestos abatement, was required in the area in preparation for condition assessment, planning, and cable replacements. Scaffolding and access platforms were required to be erected, and once the asbestos abatement process was completed, an assessment was initiated to quantify the full extent of the damage. The scope of work due to the fire damage included the replacement of 15 m of approximately 100 damaged cable sections, which are comprised of 600 V and 120 V power feeds, controls cables, and instrumentation cables, by splicing in new cables using intermediate junction boxes, and replacement of damaged electrical conduits. The motor control center servicing the Unit 2 boiler flame scanner air fan had a damaged starter that required replacement. The boiler ignitor air system flexible ducts were also replaced and all boiler flex duct connections on this unit were modified to prevent future failures.

4.0 Project Justification

The sectional replacement of electrical, controls, instrumentation cables, and conduits, and the replacement of the motor control centre starter that was damaged during the fire on Unit 2 were necessary for the restoration of Unit 2, thereby enabling Hydro to provide safe, least-cost, reliable electrical service to customers. The immediate impact of the fire on Unit 2 was the loss of 165 MW of generation on the Island Interconnected System. Due to the requirement to meet customer demand, this significant reduction in generating capacity for Holyrood and the Island Interconnected System at that time could not be sustained. In order to restore the unit and provide supply to the Island Interconnected System, the most appropriate course of action was to expedite the sectional replacement of cables, conduits, and the motor control centre starter that were damaged during the fire. Waiting to replace the damaged cables until the next capital budget process was deemed not appropriate or acceptable as the unit would have been offline for the remaining 2017 operating season, plus the following winter due to the timelines associated with the capital budget cycle.[1] Also, utilizing the supplemental capital budget process would have added several weeks to the schedule before the unit could be returned to service. Hydro determined that this was also not appropriate as the capacity of the unit was required to meet customer requirements as soon as possible following the fire.

5.0 Project Cost

The expected total expenditure for this project is $541,673. A breakdown of the cost components is provided in the Table 1.

Table 1: Project Cost

Project Expenditures	
Labor	$385,101
Materials	$73,292
Contract	$83,280
Total	**$541,673**

6.0 Future Plans

There are no future plans to complete full replacements of cables that were damaged during the May 2017 fire on Unit 2. Sectional cable replacements have been completed, boiler ignitor air system flexible ducts were replaced, and all boiler flex duct connections were modified to prevent future failures. All systems affected by the fire have been commissioned and there are no current reliability issues that require immediate attention. The boiler ignitor air system flexible ducts will also have to be replaced and all boiler flex duct connections modified on Unit 1 to prevent future similar failures. This

[1]Using the 2018 Capital Budget Application process would mean that Hydro would not apply for approval of the fire damage rehabilitation project until Summer 2017, with approval likely to occur in late Fall 2017. This would mean that the project could not proceed until a scheduled unit outage in Summer 2018.

work will be completed during the scheduled 2017 annual maintenance outage for Unit 1 under the approved budget for the Refurbish and Replace Critical Systems capital project, and report it in the annual Capital Expenditures report. Unit 3 is of a different design and does not have this issue.

7.0 Conclusion

The replacement of cabling and equipment was of an urgent and unforeseen nature, and was required to enable Hydro to restore and maintain reliable service to customers. A prolonged delay in reinstating generating capacity at this time of year would have had negative consequences to the customers served by the Island Interconnected System. Given the presence of the asbestos in the area of the cabling, safe removal was paramount prior to allowing the work crews to make a detailed assessment. Therefore, the full extent of the damage could not be determined until the asbestos was removed. Upon completion of the site preparation work, including the asbestos abatement, it was identified that a length of 15 m of 100 various cables had to be replaced. Refurbishment was determined to be capital in nature, requiring the Allowance for Unforeseen Items account; however, the extensive asbestos cleaning and the requirement to erect scaffolding to complete a condition assessment resulted in a delay in Hydro notifying the Board of the intention to utilize the Allowance for Unforeseen Items account.

Hydro respectfully submits this report detailing the costs of $541,673[2] associated with replacement of cabling and equipment damaged during the May 2017 fire on Unit 2.

[2] Submission of costs reported to date. This value may change marginally as final costs are received.

Appendix A – Unit 2 Fire Damage

Figure 1 – Unit 2 Fire Damage (A)

Figure 2 – Unit 2 Fire Damage (B)

NL HYDRO, HOLYROOD THERMAL GENERATING STATION

Unit 2 Boiler Opacity Excursion

A TapRooT Investigation, Findings, Report and Recommendations on the October 28, 2017 Incident

Jamie Curtis, P.Eng.

7-March-2018

REGISTERED PROFESSIONAL ENGINEER
PEG Newfoundland and Labrador
JAMIE CURTIS
SIGNATURE
9-Mar-2018
DATE
NEWFOUNDLAND & LABRADOR

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Executive Summary

On October 28, 2017, Unit 2 at the Holyrood Thermal Generating Station (HTGS, Holyrood) was in operation after returning to service that day from the annual maintenance outage. At 20:00h during operation, the unit distributed control system (DCS) identified an opacity alarm associated with Unit 2. The opacity alarm identifies an opacity of 20% or greater. The board operator adjusted the excess oxygen (O2) as per HTGS procedure; however, at 20:05h the excess O2 available for fuel oil combustion went to 0%. The unit operator continued to operate the unit between 58-62% opacity levels. At approximately 21:30h, a control room operator noticed there was boiler gas leaking from unit 2 air heaters. Unit 2 was shut down to investigate the cause of the boiler gas leaks. The result of running the unit at elevated opacity levels for approximately 80 minutes was soot being expelled over the community of Holyrood damaging resident's property.

The casual factors for this event were:

- Fuel oil mass flow meter (the spare) that was installed was returned from the original equipment manufacturer (OEM) with a different scaling that was greater and in different units of flow measurement from the fuel oil mass flow meter that was identified as being in need of calibration and removed from the system. Because of this, the system was sending fuel oil into the boiler that was not subject to complete combustion causing fuel oil carry over through the boiler and into the air heaters;
- The plant did not verify prior to installation if the new mass fuel flow meter (the spare) was the same calibration as the fuel oil mass flow meter removed;
- Fuel oil pressure noted as high (1813.2 kPa, 1650 kPa is normal) in the station log on unit 2 during night shift of October 28, 2017 which should have indicated an issue with the fuel oil system;
- Opacity alarm during event was not addressed by operations as per HTGS procedure: 0542 (POI-62 Boiler Operation - Opacity Monitor Control Points). The HTGS procedure states *"should the opacity monitoring alarm sound, the operator should adjust the firing pattern and/or excess O2 (within unit constraints) to*

reduce the opacity of the unit. In circumstances where the opacity cannot be controlled, the Shift Supervisor should contact the operations on-call person to notify them of the problem, initiate a SWOP and investigate the cause of the opacity excursion. In extreme cases, load shifts to other available units or de-rating the unit may be considered by the on-call person."

Initial Conditions

On September 19, 2017 a corrective work request was entered to calibrate the Unit 2 fuel oil mass flow meter. The Unit 2 fuel oil mass flow meter work request was entered because it was out of calibration (the reconciliation of fuel oil burned did not equal the amount of fuel oil measured). This work request was entered during the Unit 2 maintenance outage and not included on the original annual corrective list developed by Maintenance Planning and Plant Operations prior to the start of the Unit 2 outage on July 31, 2017.

Initiating Events

Holyrood plant staff replaced the Unit 2 fuel oil mass flow meter with a plant stocked spare during the Unit 2 annual maintenance outage The fuel oil mass flow meter (the spare) that was installed was returned from the OEM with a different configuration (scaling was greater and in different units of flow measurement) from the fuel oil mass flow meter that was removed. The plant did not know the scaling on the new fuel oil mass flow meter was different nor did they verify that the mass fuel flow meter installed was the same calibration as the fuel oil mass flow meter removed.

Startup of Unit 2 began on October 26, 2017. On October 28, 2017 at 19:11h, the unit was synchronized and began to increase load.

Incident Description

At 20:00h, the Unit 2 load was 40 megawatts (MW) and the opacity was at 31.50%. During operation, the unit DCS identified an opacity alarm associated with Unit 2. The opacity alarm identifies an opacity of 20% or greater. At 20:05h, the operator tried to control the opacity as per HTGS procedure: 0542 (POI-62 Boiler Operation - Opacity Monitor Control Points) by increasing the O2 to the boiler. From 20:00h until 21:20h, the average opacity was between 58-62%. The emissions during this time were:

- Carbon monoxide (CO) was greater than 500 parts per million (ppm). The normal range for CO is less than 10 ppm.

- Sulphur dioxide (SO2) was greater than 1000 ppm. The normal range for SO2 is less than 350 ppb.

Both CO and SO2 readings were greater than the above readings; however, plant systems are not setup to read outside the above ranges of 500 ppm for CO and 1000 ppm for SO2.

At 20:05h, the Unit 2 load was 49 MW and the opacity was 58.20%. At 20:09h, the station shift supervisor noted the fuel oil header pressure as high (1813.2 kPa, 1650 kPa is normal). Operations continued to vary the loading on Unit 2 for the next 75 minutes unit 21:20h.

Time	MW	Opacity (%)
19:10	0	8.90
20:00	41	31.50
20:05	49	58.20
20:12	48	62.30
21:00	40	62.30
21:20	50	62.30
21:30	33	25.90
22:00	33	14.00

During this 75 minute period, the opacity was between 58.20% and 62.30%. At 21:30h, a control room operator noticed there was boiler gas leaking from the unit 2 air heater. Unit 2 was shut down at 23:29h to investigate the cause of the boiler gas leaks. The result of running the unit at elevated opacity levels for approximately 80 minutes was soot being expelled over the community of Holyrood damaging resident's property.

Immediate Corrective Actions

Unit 2 was shut down at 23:29h to begin installing work protection permits for maintenance to repair the boiler gas leaks on the air heaters. On October 29, 2017 at 01:15h, work protection permits were installed and maintenance began repairing the boiler gas leaks. Maintenance on the Unit 2 boiler gas leaks was completed on October 29, 2017 and on October 30, 2017 at 07:32h Unit 2 was synchronized. Due to Unit 2 turbine bearing maintenance issues, the Unit was taken offline at 16:33h on October 30, 2017. On November 1, 2017 at 18:51h, Unit 2 was synchronized; however, due to opacity alarms, the operator reduced loading on Unit 2 to 40 MW to control the opacity levels as per HTGS procedure. The startup on November 1, 2017 was acceptable as per HTGS procedures. On November 2, 2017, investigation into the opacity alarms by plant staff discovered that the Unit 2 fuel oil mass flow meter was incorrectly calibrated with a scaling that was greater than the fuel oil mass flow meter that was removed from service. The fuel oil mass flow meter controls were modified to match scaling in the DCS and the plant was able to increase the loading on Unit 2. On November 2, 2017 at 17:00h, the plant increased the loading on Unit 2 from 40 MW to 70 MW without any opacity issues.

Casual Factors and Corrective Actions

The casual factors for this event are:

- Fuel oil mass flow meter (the spare) that was installed was returned from the original equipment manufacturer (OEM) with a different scaling that was greater and in different units of flow measurement from the fuel oil mass flow meter that was identified as being in need of calibration and removed from the system. Because of this, the system was sending fuel oil into the boiler that was not subject to complete combustion causing fuel oil carry over through the boiler and into the air heaters;
- The plant did not verify prior to installation if the new mass fuel flow meter (the spare) was the same calibration as the fuel oil mass flow meter removed;
- Fuel oil pressure noted as high (1813.2 kPa, 1650 kPa is normal) in the station log on unit 2 during night shift of October 28, 2017 which should have indicated an issue with the fuel oil system;
- Opacity alarm during event was not addressed by operations as per HTGS procedure: 0542 (POI-62 Boiler Operation - Opacity Monitor Control Points). The HTGS procedure states *"should the opacity monitoring alarm sound, the operator should adjust the firing pattern and/or excess O2 (within unit constraints) to*

reduce the opacity of the unit. In circumstances where the opacity cannot be controlled, the Shift Supervisor should contact the operations on-call person to notify them of the problem, initiate a SWOP and investigate the cause of the opacity excursion. In extreme cases, load shifts to other available units or de-rating the unit may be considered by the on-call person."

The corrective actions for this event are (not in order of priority, all actions are of equal importance):

- Complete environmental awareness with Operations to detail their responsibilities with respect to the plant certificate of compliance with the Department of Environment and Conservation. Identify parameters and procedures to follow during unit operation, startup, shutdown and maintenance;
- Update startup procedures to include reference to obligations to the plant compliance with the Department of Environment and Conservation and environmental controls;
- Develop and implement a maintenance procedure to verify existing equipment settings, calibrations, positions or the like are replaced in kind during maintenance, overhauls, recalibrated or the like. Ensure that changes to any equipment are documented and signed using the management of change process;
- Develop and implement (or modify existing) a check sheet to identify and confirm the correct position of safety and operational controls (i.e.: transmitters, positioners, valves) prior to startup;
- Ensure that valves associated with transmitters are included on the major permit such that they are captured on the PC17A (switching order) to ensure they are in the correct position prior to startup;
- Ensure all plant events recorded in the station log are sequential with time stamps. The station log must also include all signatures and initials as per indicated sections;

- Ensure operator and shift supervisor training includes key performance indicators or a way to address, control and/or correct operational conditions outside normal parameters;
- Investigate and develop a process to ensure that critical boiler feedback parameters (i.e.: the boiler furnace pressure trip) are calibrated and functioning correctly before any boiler is placed into service;
- Ensure all incidents are investigated using a formal root cause analysis that begins no more than three (3) working days after an incident occurs;
- Modify existing HTGS procedure 0542 (POI-62 Boiler Operation - Opacity Monitor Control Points) to include specific and direct instructions with references to opacity and timelines such that known and accepted actions can be taken by operations in the event of an opacity event exceeds thresholds established by the procedure. Communicate to all operation personnel the changes made to the procedure.

Investigators

The investigators for this event were Steve Kelly (Environmental Technologist, 29 years with HTGS), John Rose (Environmental Technologist, 29 years with HTGS) and Jamie Curtis (Mechanical Engineer, 10 years with HTGS).

Distribution

Jeff Vincent, Manager, Holyrood Thermal Generating Station

John Adams, Manager, HTGS Long Term Asset Planning

Tracy Smith, Manager, HTGS Safety, Health and Environment

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Fire on Unit 1 Turbine Bearing #2
SWOP: 2018001375
February 22, 2018

Investigating Supervisor	
Manager (Safety Leader One)	
Regional/LOB Safety Coordinator (Safety Leader Two)	

PRIVELEDGED REPORT

Internal Use Only

CONFIDENTIAL

To ensure the confidentiality of the witness statements, this investigation report is intended for internal use only. It is to be reviewed and discussed by supervisors and management only.

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High Potential Incident Report [February 2018]

1.0 Executive Summary

On February 22, 2018 at approximately 4:50 PM a fire occurred on Unit 1 Turbine Bearing #2. The Plant evacuation alarm was initiated and ERT were notified immediately. Operations crew and ER Technicians extinguished the fire. The "All Clear" was given at approximately 5:10 PM. There was significant smoke in the Powerhouse, however it was eliminated within 20 mins of extinguishment and the air quality reported to be good at approximately 5:30 PM. There were no injuries or further equipment damage.

The incident prompted an investigation. The investigation produced two (2) immediate contributing factors, one (1) basic contributing factor and three (3) corrective actions. An additional finding (1) was noted.

Immediate Contributing Factor:

1. Inadequate Instruction;
2. Inadequate Guards/Barriers.

Basic Contributing Factors:

1. Leadership and/or Supervision.

Additional Finding:

1. Inadequate Maintenance.

Corrective Actions:

1. Update/develop procedure to switch Lube Oil to "Seals Only " when units are off turning gear and the generator is pressurized;
2. Complete an inspection on Turbine Bearing #2 during the next scheduled Unit 1 Turbine Outage;
3. Create or modify existing checklist for field verification to ensure all maintenance and/or repairs have been complete prior to removal of permit or work order closed;

2.0 Background Information

On January 20, 2018 there was a forced outage on Unit 1 as a result of excessive movement on the Turbine Control Valve. The Servo Control cable was also replaced during this outage. While Operations were attempting to restart the unit, the Boiler Stop Valve failed, thus resulting in Unit shutdown.

On February 22, 2018 Unit 1 was returning to Operation after extensive maintenance, when a fire occurred on the Turbine Bearing #2. The Plant evacuation alarm was initiated and ERT were notified immediately. Operations crew and ER Technicians extinguished the fire. There was significant smoke in the Powerhouse however it was eliminated within 20 mins of extinguishment and the air quality reported as good. There were no injuries or further equipment damage. The fixed fire protection on the unit did not activate, as there was insufficient heat in the vicinity of the sprinkler heads. The fire panel was inspected and the unit pre-action fire systems were active, with no damage.

Unit 1 Turbine Generator

The Cause of the fire was a result of exposed Insulation that had absorbed Lube Oil and "flashed" when the unit was heating up. While Unit 1 had been offline for Maintenance repair, there was a period of time that the Turning Gear on the Turbine had been shut off but the Lube Oil pressure remained on the bearing. Lube Oil had leaked and was absorbed in a replaced section of pipe insulation below the bearing that did not have protective cladding. The source of the oil was Bearing #2. A visual inspection was complete following the incident, but there was no obvious identification of why the leak has occurred. If cladding had been present it is likely that the oil would have ran down the cladding and "pooled" at a location that could have potentially been observed by an Operator during completion of the Turbine Checklist.

Exposed Pipe Insulation

3.0 Table of Roles and Responsibilities

Name	Position	Roles and Responsibilities
Jason Penney	Emergency Response Technician (ERT)	Emergency Response
Mike Murphy	Emergency Response Technician (ERT)	Emergency Response
Dean Cantwell	Emergency Response Technician (ERT)	Emergency Response
Tom Keats	Operator	

4.0 Incident Timeline

- 4:50 PM: Fire on Unit 1 Bearing 2;
- Plant alarm was initiated and ERT notified;
- ERT and the Operator extinguished the fire;
- 5:00 PM: ER Coordinator notified;
- 5:10 PM: All Clear given;
- 5:30 PM: ER Coordinator on site:
- 5:30 PM: All fire systems were verified;
- ERT coverage remained in place as precaution.

5.0 Detailed Description of Events

On February 22, 2018 at approximately 4:50 PM a fire occurred on Unit 1 Bearing #2. The Plant evacuation alarm was initiated and ERT were notified immediately. Operations crew and ER Technicians extinguished the fire. The "All Clear" was given at approximately 5:10 PM. The ER Coordinator was notified at 5:00 PM and onsite at 5:30 PM. There was significant smoke in the Powerhouse however it was eliminated within 20 mins of extinguishment and the air quality reported to be good at approximately 5:30 PM.

The fixed fire protection on the unit did not activate, as there was insufficient heat in the vicinity of the sprinkler heads. The fire panel was inspected and the unit pre-action fire systems were active, with no damage. All fire systems were verified at 5:45 PM.

ER Technician continued to monitor the area, completing checks and verification of heat with Thermal Imaging Camera.

6.0 Analysis of Contributing Factors

<u>Immediate Contributing Factor:</u>

1. Inadequate Instructions/Procedure;

   The Lube oil pressure remained on the Bearing when the turning gear was shut off. Discussion with Operation Specialists and Manager, as well as review of available procedures related to the Turbine/Generator, there is no documentation where it states that when the turning gear is turned off that the Lube Oil pressure is to be switched to "Seals Only".

2. Inadequate Guards/Barriers.

   Cladding not replaced on Insulation.

<u>Basic Contributing Factors:</u>

1. Leadership and/or Supervision:

   Inadequate procedures, practices or guidelines – the Lube Oil Pressure remained on the Bearing. It is not identified in any Operational procedure/guideline to remove the pressure from the Bearing when the turning gear is off - when no maintenance is being performed on the turbine. Experienced personnel may understand that it would be required to switch to "Seal Only" however it is not documented in any procedure.

Additional Findings (Gap identified that indirectly resulted in the incident)

Inadequate Maintenance.

Maintenance job was not complete - no cladding installed on the Insulation. Lube oil was absorbed in the exposed insulation.

7.0 Existing Controls that failed

Hazard Recognition Evaluation and Control:

- Maintaining Lube Oil pressure on the Bearing and the possibility of leaking.

Guards and Barriers

- Insulation should have not remained exposed. The cladding should have been replaced.

8.0 Recommendations/ Lessons Learned

1. Develop and implement a procedure for switching the Lube Oil to "Seals Only" and removing the Lube Oil pressure from the Bearings when the generator is pressurized and turning gear is shut off. In addition, Operations should closely monitor and assess for Lube Oil on the Bearing during start-up;

2. Implement Field Verification Checklist as part of the close-out process for work. The cladding was not replaced on the Insulation.

9.0 Action Plan

Action	Responsible	Target Date
Update and/or implement procedure to switch Lube Oil to "Seals Only" when off turning gear.	Evan Cabot	July 31, 2018
Have an inspection complete on Turbine Bearing #2 during next scheduled Unit 1 Turbine Outage *.	John Adams	September 30, 2018
Create or modify existing checklist for field verification to ensure all maintenance and/or repairs have been complete prior to removal of permit or work order is closed.	Todd Collins	July 31, 2018

*upon visual inspection following the incident, there was no obvious identification of why the Lube Oil had leaked. To ensure that there are no issues or damage, the Bearing will be inspected during the next scheduled Unit 1 Turbine outage.

10.0 Pictures

High Potential Incident Report [February 2018]

High Potential Incident Report [February 2018]

INCIDENT INVESTIGATION REVIEW

Manager: [Print/Type Name] Evan Cabot

Comments:

___

___

Signature: ________ Date: 2018/06/12

Manager: [Print/Type Name] John Adams

Comments:

___

___

Signature: ________ Date: 2018/06/14

Manager: [Print/Type Name] JEFF VINCENT

Comments:

___

___

Signature: ________ Date: 2018 - JUNE - 21

UNIT-1 EAST FD FAN INBOARD BEARING FAILURE REPORT

1. SUMMARY

On 16, June, at 23:15 hours Unit-1 was desynchronized and placed on turning gear for electricians to replace worn out Generator brushes. On 17, June at 00:08 hours, Fuel Oil Heater set was found to be blowing oil from the discharge pressure gauge piping. The discharge pressure gauge appeared to have blown off. The East FD fan along with West FD fan was shut down at 00:15 hours and 00:18 hours respectively. Enviro Systems cleaned up the oil spill. On 17, June. at 14:05 hours ignitors were lit off to pre warm. At 14:30 hours, the east FD fan in board bearing vibration was observed to be 12.93 microns, the vibration being higher than the alarm value which is 7 microns. The bearing was found to be hot and hence the FD fan was shut down. The bearing was disassembled. On inspection the bearing babbit was found to be badly scored.

2. INVESTIGATION

2.1 Observation

1. Spike in bearing lube oil temperature prior to shutting down the fan,
2. High vibration prior to shutting down the Fan
3. The scoring on the bottom half of the bearing.
4. Loss of babbit at the leading edge of the bottom half of the bearing.
5. Dirt in the bearing cooling water housing.
6. Burr on the rotor journal.

2.1.1 Spike in bearing lube oil temperature prior to shutting down the fan.

The bearing lube oil temperature trends from 6, Feb to 18, Jun was printed from DCS. The date, 6, Feb was selected to rule out the possibility of abnormal lube oil temperature increase due to the ingress of dirt or any other foreign material into the bearing from the Unit-1, Air Heater wash on 2, Feb.

The temperature ranged from 60 deg C to 75 deg C depending on Unit load and cooling water flow. Normally the higher temperature being at 130 MW. On 14, June at 14:40 hrs, the bearing lube oil temperature has spiked to 73 deg C from 58 deg and then stabilized at 57 deg C, the load being 70 MW. However at the time of FD Fan bearing failure the temperature was 57 deg C which was a normal temperature for 70 MW. The spike would have been either due to the temporary blockage of cooling water or an indication of liberated babbit fragments causing obstruction to lubrication inside the bearing.

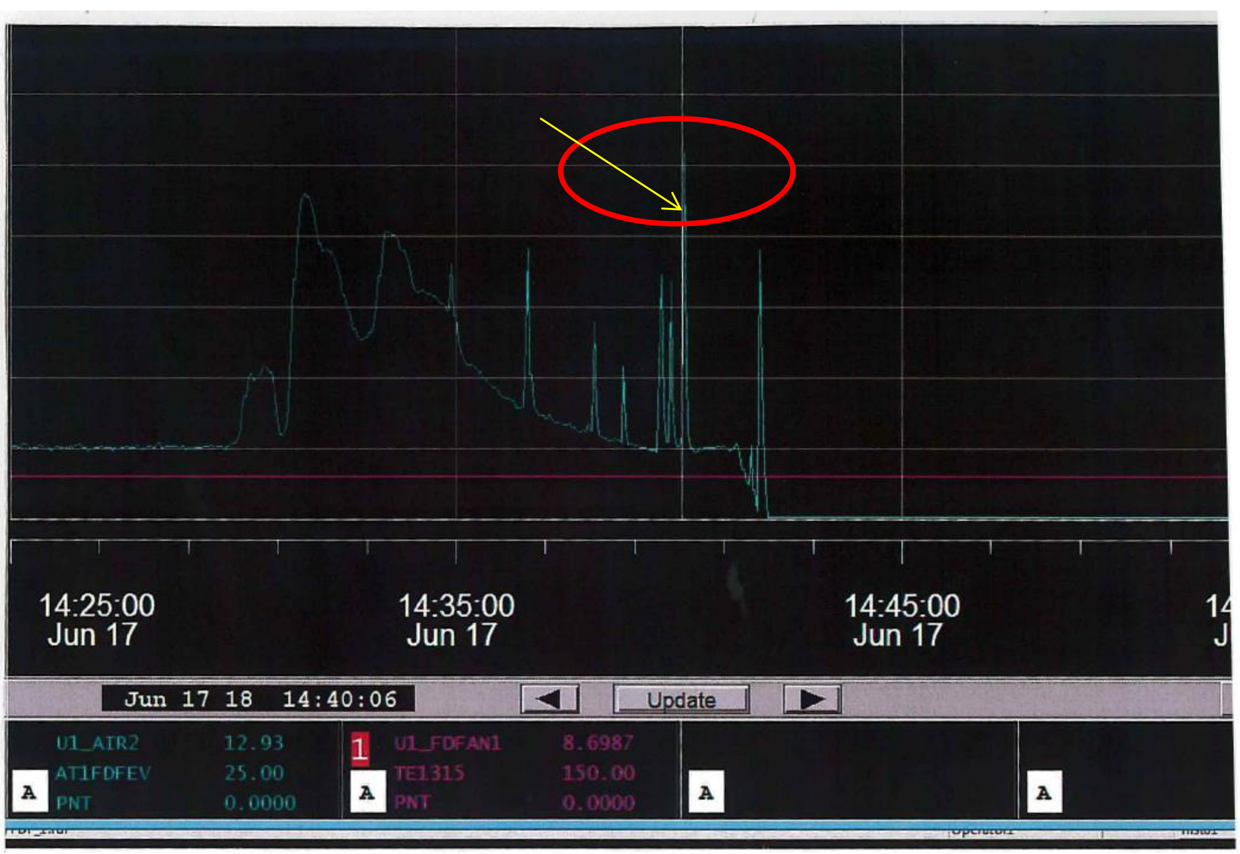
2.1.2 High vibration prior to shutting down the fan.

The Instrumentation group periodically measures vibration of FD fans. They had taken measurements on the following dates :

#	DATE	VIBRATION IN MICRONS		
		Axial	Horizontal	Vertical
1	2017-12-6	0.4	2.4	0.95
2	2018-1-10	1.3	1.75	0.69
3	2018-2-4	0.4	2.25	4
4	2018-5-10	1.52	3.00	1.1

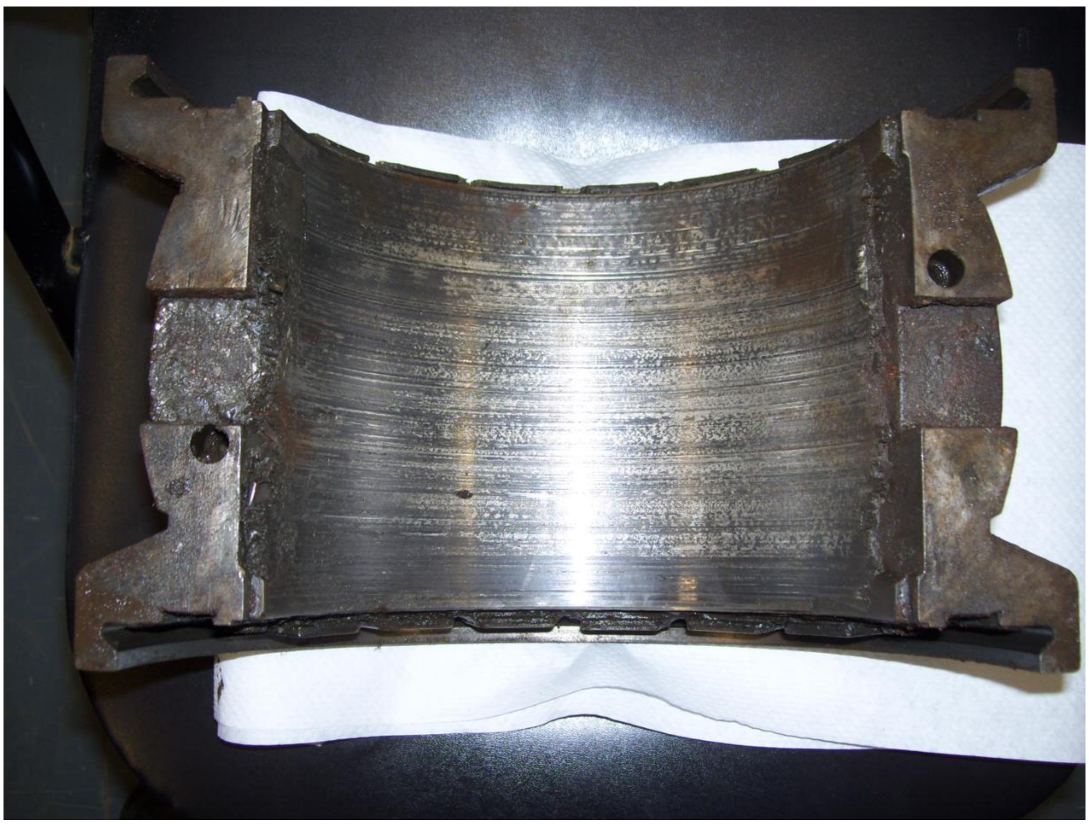
The above readings shown in the Table do not indicate a high vibration in the bearing.

The inboard vibration of the bearing had spiked to 12.93 microns prior to shut down as seen in the DCS print out. The alarm for high vibration is 7 microns and the trip is 20 microns. The DCS print showing the 12.93 micron vibration is as shown below:

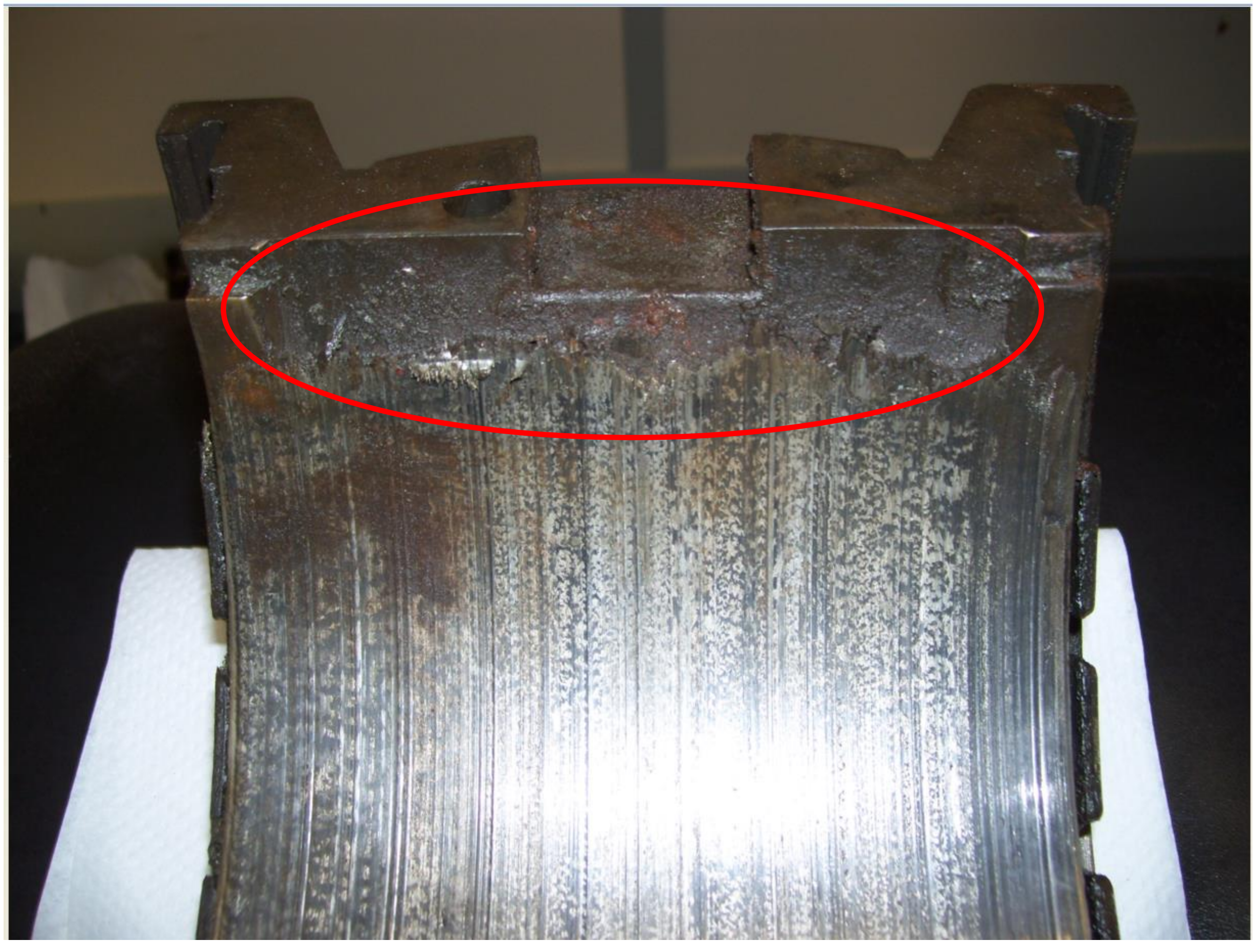


2.1.3 The scoring on the bottom half of the bearing

The scoring at the bottom half of the bearing indicates ingress of material between the journal and the babbit. The bearing housing is sealed by half an inch thick rope packing and hence there is no possibility of any material entering bearing. The scores were the result of liberated babbit getting between the journal and the bearing.



2.1.4 Loss of babbit at the leading edge of the bottom half of the bearing.



The loss of babbit at the leading edge of the bottom half indicates fatigue failure. Fatigue failure would begin as cracks at the leading edge of the bearing half and will progress to babbit loss. Fatigue failure is caused mainly due to cyclic loading. The bearing halves were never checked for cracks either by dye penetrant or ultrasonic examination during outages.

2.1.5 Dirt in the bearing cooling water housing

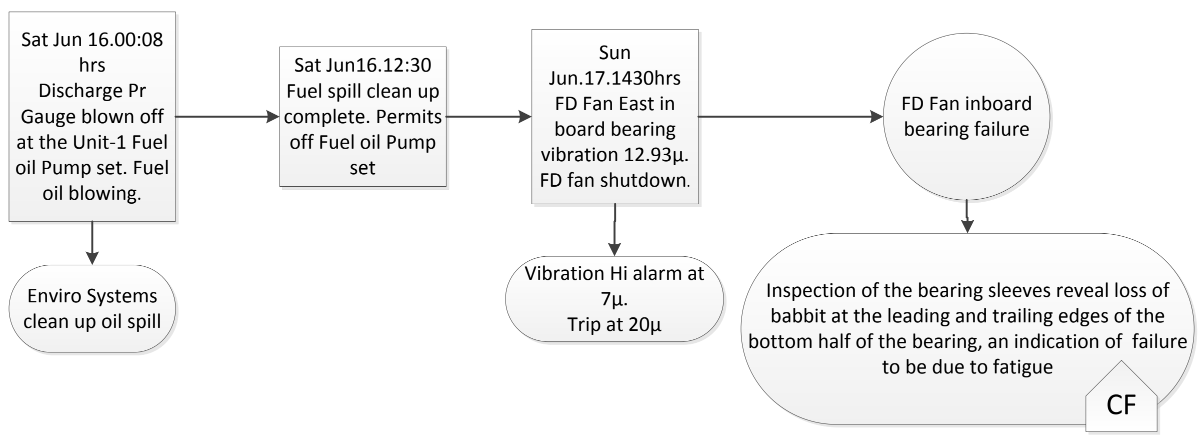
A lot of dirt was found in the cooling water housing of the bearing. This was due to the cooling water piping not cleaned during the last outage. This job was omitted so as to meet the outage schedule. However, the dirt in the cooling water pipes did not cause any high temperature in the bearing. The temperature hovered around 60 deg C for most of the load.

2.1.6 Burr on the rotor journal.

Bits of babbit in the bearing have diminished the polish on the rotor journal and henc the burr on the journal

3. Time line as shown in SNAP CHART

SNAP CHART OF UNIT-1 EAST FD FAN INBOARD BEARING FAILURE 16 June 2018



4. <u>Analysis of Contributing Factors</u>

<u>Immediate Contributing Factor</u>

1. High Vibration
2. Spike in bearing temperature

<u>Basic Contributing Factor</u>

1. Fatigue failure of babbit. Dye Penetrant or Ultrasonic testing of babbit during Boiler outage would have identified fatigue failure cracks .
2. Dirt in cooling water piping to the bearing. Flushing the cooling water piping during Boiler outage would have resulted in a larger cooling water flow to the bearing, thus lowering the bearing temperature which in turn would have increased the threshold limit of the stress levels on the babbit.

5. <u>Recommendations/ Lessons Learned</u>

1. Plant equipment requires periodic review of preventative maintenance strategies based on the service life of equipment. Strategies should be revised as required.
2. FD fan PM should be upgraded.

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Unit 1 Fuel Oil Set – Bunker C Fuel Oil Spill
SWOP: 2018004992
June 16, 2018

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1.0 Executive Summary

On June 15 2018, Unit 1 at Holyrood Thermal Generating Station (HTGS) was scheduled to come off line for Generator Brush replacement. At 10:25 PM, Operations started to unload Unit 1 and at 11:15 PM, the unit was Desynchronized and placed on Turning Gear. At 12:08 AM on June 16 2018, the Electricians notified the Shift Supervisor that there was an indication of a Fuel Oil leak on Unit 1 Fuel Oil Set. The Shift Supervisor, along with the outside Operator discovered that the Pressure Gauge on the discharge of the Primary Pump (East) had "let-go", resulting in the release of Bunker C Fuel Oil. Operations isolated the source of Bunker C, contained the oil spilled using the Spill Kit and closed the Isolation valve on the Continuous Basin. The Boiler was shut down at 12:20 AM June 16. There were no injuries or equipment damage. HTGS employees were assisted by Enviro Systems to complete cleaning and removal of oil.

This incident prompted an investigation using Tap Root. The investigation has produced one (1) Causal Factor:

1. Loose Pressure Gauge connections.

2.0 Incident Description

On June 15 2018, Unit 1 at Holyrood Thermal Generating Station (HTGS) was scheduled to come off line for Generator Brush replacement. At 10:25 PM, Operations started to unload Unit 1 and at 11:15 PM, the unit was Desynchronized and placed on Turning Gear.

On June 16 2018, at 12:08 AM, the Electricians notified the Shift Supervisor that there was a Fuel Oil leak. Both the Shift Supervisor and Outside Operator went to investigate and discovered that the source of the Bunker C fuel oil was a Pressure Gauge that had "let-go" on the discharge of the Primary Pump (East) on Unit 1 Fuel Oil Set. The Shift Supervisor notified the Control Panel Operator, who removed the oil from the burner and shut down the pumps. Both the Shift Supervisor and Outside operator isolated the suction and discharge of the pumps, and closed the isolation valve on the Pressure Gauge that had "let-go". The Control Panel Operator shut down Unit 1 Boiler at 12:20 AM.

At 12:13 AM, the on-call manager and ERT (Emergency Response Technician) Coordinator were both notified of the Bunker C Fuel Oil incident and at 12:45 AM the ERT Coordinator was onsite and assumed the role of OSC (On Scene Commander). SNL (Service Newfoundland and Labrador) and Coast Guard were notified at 2:31 AM. Enviro Systems were contacted at 2:40 AM and requested to provide the resources required to assist HTGS employees complete the cleanup. They arrived on-site at 5:00 AM.

Figure 1: Snap Chart provides a detailed sequence of events.

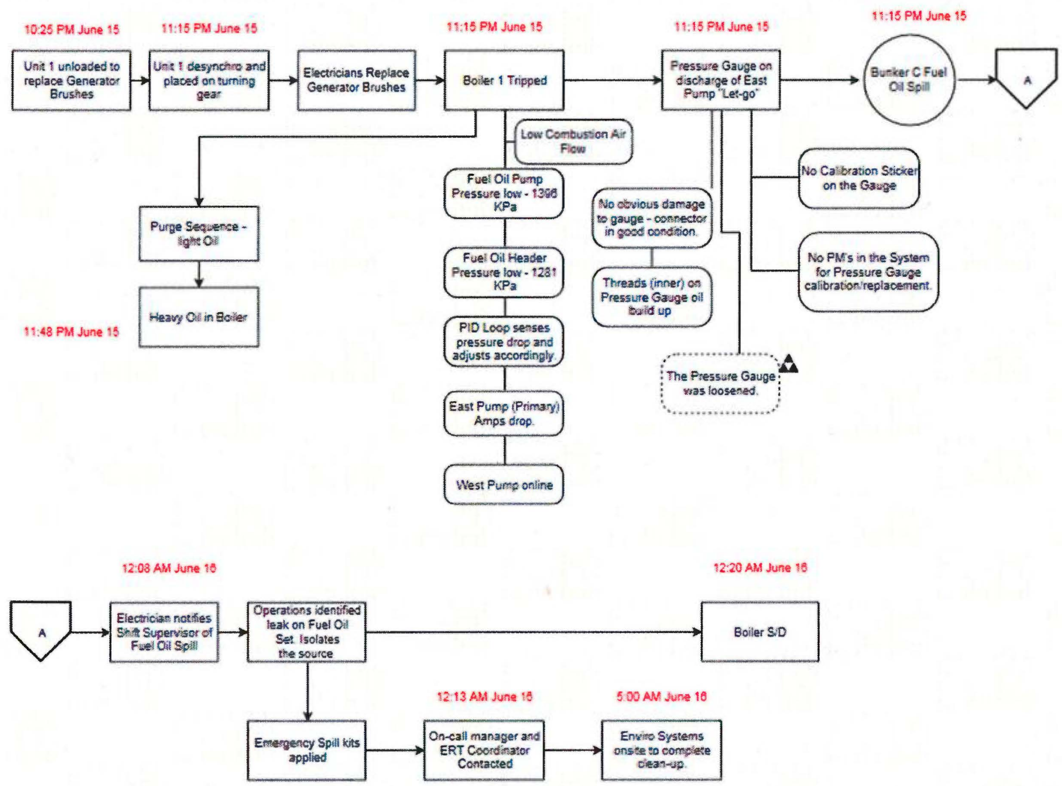

Figure 1: Snap Chart (Tap RooT) – Sequence of Events

3.0 Immediate Corrective Action

The Control Panel Operator removed heavy oil from the burner and shut down the pumps. Both the Shift Supervisor and Outside Operator isolated the suction and discharge of the pumps, and closed the isolation valve on the Pressure Gauge that had "let-go". The Control Panel Operator then shut down Unit 1 Boiler.

4.0 Causal Factors and Corrective Action

Causal Factor: Loose Pressure Gauge Connection.

Root Cause – two (2) possibilities:

1. Vandalism or Destruction – the Pressure Gauge was intentionally loosened;

Inspection of the Pressure Gauge that had "let-go" and the connectors did not have any apparent thread damage – maintenance did not have to replace the coupling or nipple, only the pressure gauge. This would lead one to believe that the Pressure Gauge had been loosened. If the connection was tight when it "let-go", then there would have to be thread damage to one or both of the components. Also, during the inspection of the Pressure Gauge, the threads closest to the gauge itself had a buildup of oil – see photo below.

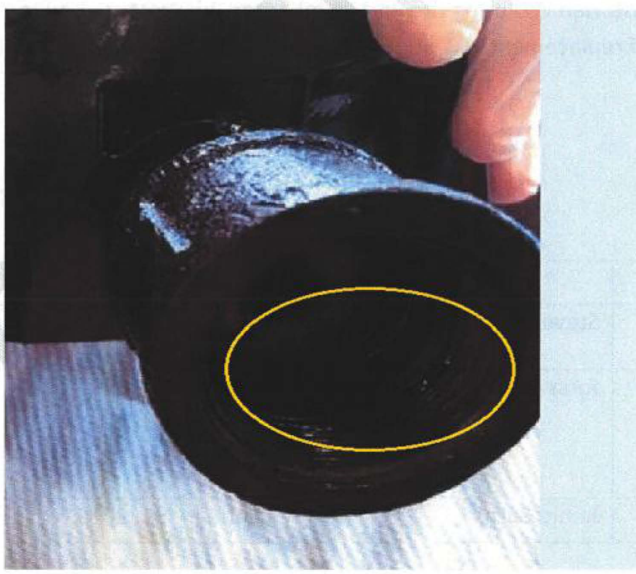

Photo 1: Pressure Gauge

The oil would indicate that there was not a complete connection and that the Pressure Gauge had been loosened or not tightened when installed.

Also note that the components of the Pressure Gauge were designed for the appropriate temperature and pressure.

2. Inadequate or Incorrect Tools – the Pressure Gauge was accidentally loosened.

The Valve Wrench is used in the field to tighten valves. Depending on the size and/or length of the wrench, it is possible that the tool would "strike" the pressure gauge and loosen it while tightening the valve.

Corrective Actions:

1. Consider installation of mobile surveillance – "Go Pro Style";
2. Develop a "Return to Service Checklist", to be complete on the Fuel Oil Set;
3. Review tools used for the Job.

5.0 Additional Information

No PM in the System for Pressure Gauge calibration/replacement.

The Pressure Gauge that had "let-go" did not have a calibration sticker to indicate the last date of calibration/replacement. Review of historian WO using the Part Number for the Pressure Gauge revealed that the last potential date of replacement was August 2012. WO description lacks details of work completed.

6.0 Action Plan

Action	Responsible	Target Date
Consider installation of mobile surveillance.	Steve Connolly	June 30, 2019
Develop a "Return to Service Checklist", to be complete on the Fuel Oil Set – not just the Pressure Gauges but the entire Fuel Oil Set.	John Adams	March 29, 2019
Review tools used for the Job.	Jamie Curtis	January 31, 2019

7.0 Investigators

The investigators for this event were Jamie Curtis (Manager – Work Execution (Acting), 10 years with HTGS) and Tracy Smith (Manager – Safety, Health and Environment, 1 year with HTGS).

8.0 Distribution

Jeff Vincent – Senior Manager

Evan Cabot – Manager, Operations

John Adams – Manager, Long Term Asset Planning

Jamie Curtis – Manager (Acting), Work Execution.

9.0 References and Attachments

1. Eta Pro trends;
2. Alarm Manager;
3. Shift Supervisor Log;
4. ERT Coordinator Log Report;
5. Employee Interviews;
6. P&ID 238-10-0210-127.

INCIDENT INVESTIGATION REVIEW

Manager: [Print/Type Name] Safety, Health & Environment TRACY SMITH

Comments:

Signature: [signature] Date: Feb 6 2019

Manager: [Print/Type Name] John Adams - Manager LTAP

Comments:

Signature: [signature] Date: Feb 6, 2019

Manager: [Print/Type Name]

Comments:

Signature:__________ Date:__________