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March 18, 2016

VIA HAND DELIVERY
Ms. Carlotta S. Stauffer
Division of the Commission Clerk and Administrative Services
Florida Public Service Commission
2540 Shumard Oak Blvd.
Tallahassee, FL 32399-0850

Re: Docket No. 160001-EI

Dear Ms. Stauffer:

Enclosed for filing are Florida Power & Light Company's responses to Staff's First Data Request (Nos. 1-5). If there are any questions regarding this transmittal, please contact me at (561) 304-5639.

Sincerely,

s/ John T. Butler
John T. Butler

Enclosures

cc: Parties of record (w/encl.)

CERTIFICATE OF SERVICE
Docket No. 160001-EI

I HEREBY CERTIFY that a true and correct copy of the foregoing has been furnished by electronic service on this 18th day of March 2016 to the following:

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s/ John. T. Butler
John T. Butler

Q.

In his 2015 September testimony regarding the February 2015 outage at St. Lucie Unit 2, at pages 6-8, witness Grissette stated that the outage was due to seawater intrusion into a condenser tube. He further stated that FPL would perform detailed testing and remove the suspect tubing during its October 2015 refueling outage, and perform lab testing to determine the root cause and perform any necessary corrective actions to prevent recurrence.

Was the detailed testing performed and the suspect tubing removed during the October 2015 refueling outage? If so, please provide a detailed summary of the results of the testing.

A.

Yes, please refer to Attachment I of this response for a detailed summary of the test results.

Exelon Generation. Exelon PowerLabs

To: **Omar Rodriguez, St. Lucie Nuclear Plant**

From: **Chris Reilly, (610)380-2432 chris.reilly@ExelonPowerLabs.com**

Project: **FLO-11149**

Subject: **Failure Analysis of Titanium Tubing from 2A1 Condenser**
Purchase Order No.: 02341346
Ref AR: 2025590

Date: **November 11, 2015**

DESCRIPTION

Background:
At approximately 0300 on 2/15/15, a significant seawater leak was detected in the Unit 2 Condenser 2A1 Hotwell. The unit was manually tripped as a result of the seawater leak into the condenser.

A Failure Investigation Team was assembled to determine the source of condenser in-leakage. A partial hydrostatic fill test was performed in the 2A1 waterbox. There were seven potential leaking tubes identified by observation of water flowing from them. A significant tube leak was identified in lower bundle tube R74-T53. Water was found leaking from this tube at the outlet side of the condenser.

During borescope inspection from the condenser outlet side of tube R74-T53 what appeared to be a "longitudinal crack" was observed approximately 5.5 feet from the tube sheet. ECT of a nearby tube, location R76-T50, was found to have a defect measuring 95% in depth with characteristics of longitudinal cracking.

Action:
Perform laboratory metallurgical analysis of selected tube samples from 2A1 waterbox tubes (lower bundle) R76-T50 and R74-T53 to identify tube failure mechanism.

The tubing is ⅞" OD, ASTM B388 grade 2 titanium (commercially pure - CP).

CONCLUSIONS

The T53 tubing segment exhibited a longitudinal crack approximately 180° from the seam weld that was OD-initiated, brittle, and appeared to be a progressive cracking mechanism. Localized titanium hydride needle formation, which results in loss of ductility, was detected in the tube at the crack location and other random locations around the tube OD. The presence of titanium hydride needles in the tube microstructure created a condition susceptible to brittle fracture in the presence of tensile hoop stresses. Flattening tests resulted in cracking, which demonstrated the loss of ductility that the tubing suffered.

Two additional contributing factors were identified that might have influenced cracking in this tube segment: 1) the crack was coincident with a gouge on the OD surface that was caused by installation into the condenser; 2) tensile residual hoop stresses were present on the OD surface. The gouge introduced a stress concentration coincident with hydride formation. Tensile residual hoop stresses were estimated to be 22 ksi, or 34-55% of the ASTM B338 yield strength for Grade 2 titanium condenser tubing.

The T50 tubing segment did not exhibit any damage that would yield an ECT cracking indication. Visual and stereomicroscope inspection and visible dye penetrant testing did not reveal any cracking. Metallography at the center of the suspect area revealed some titanium hydride formation, though to a lesser degree than observed in tube T53. There was no incipient cracking observed.

The tubing was consistent with ⅞" OD x 0.027" wall CP titanium.

COMMENTS / DISCUSSION

The exact cracking mechanism is not known, but the observation of non-uniform discoloration on the fracture surface suggests the mechanism is progressive. It is known that titanium hydride formation reduces the threshold stress required for fatigue crack initiation and propagation. However, a source of cyclic stress is not apparent. It is possible that cracking occurs in the affected microstructure due to the combined influence of service stresses, residual hoop stress, and the stress concentration created by the OD gouge. As the crack progresses, fresh metal surfaces would be exposed to form titanium hydride deeper in the tube wall and allow the crack to propagate further.

TEST PLAN

1) Photo-documentation of the as-received component
2) Photo-documentation of surface NDE
3) Sectioning to facilitate analytical methods
4) Application of analytical methods
5) Optical microscopy
6) Fractography (including measurement of striation spacing if present)
7) Scanning Electron Microscopy
8) Energy Dispersive X-ray Spectroscopy
9) Metallography
10) Interpretation of analytical results
11) Discussion of results
12) Conclusion of causative failure mechanism

STATEMENT OF QUALITY

Testing was performed with standard equipment that have accuracies traceable to nationally recognized standards, or to physical constants, by qualified personnel, and in accordance with the **Exelon** PowerLabs Quality Assurance Program.

Technician(s): Stephen Merjanian, (610)380-2472, stephen.merjanian@ExelonPowerLabs.com

Reviewed by: *Mike Minicozzi* *11/5/15*
ANSI Level III / Sr. Engineer Date

Approved by: *Chris Reilly* *11-Nov-2015*
ANSI Level III / Sr. Engineer Date

Project review and approval are electronically authenticated in the Exelon PowerLabs project record.

cc:

OBSERVATIONS AND DATA

Figure 1: As-received Tubing Segments
The following tubing segments were received.

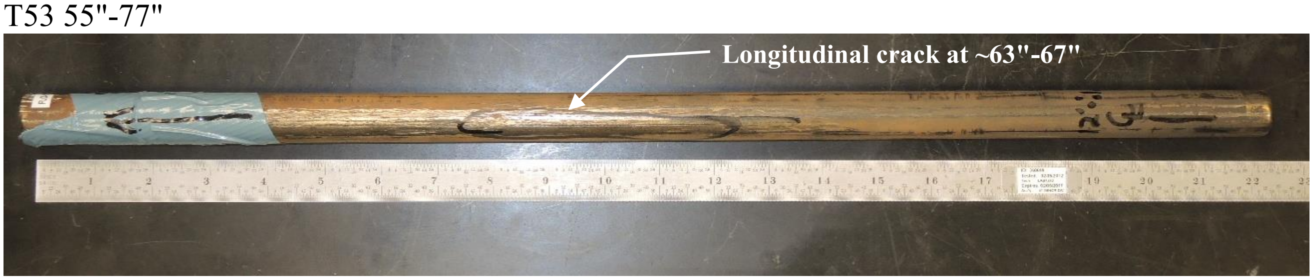
T53 40"-55" - No visible cracking or damage
T53 55"-77" - Visible longitudinal crack, approx. 4" long
T53 77"-95" - No visible cracking or damage
T50 435"-459" - No visible cracking or damage

Visible dye penetrant testing was performed on the OD of T53 55"-77" and T50 435"-459". No additional cracking was detected on segment T53 55"-77", and no indications were observed on segment T50 435"-459". The OD of each segment exhibited brown deposits (analysis in Figure 14).

Nominal tubing dimensions were 0.870" OD x 0.027" wall thickness.

T53 40"-55"

T53 55"-77"



T53 77"-95"

T50 435"-459"

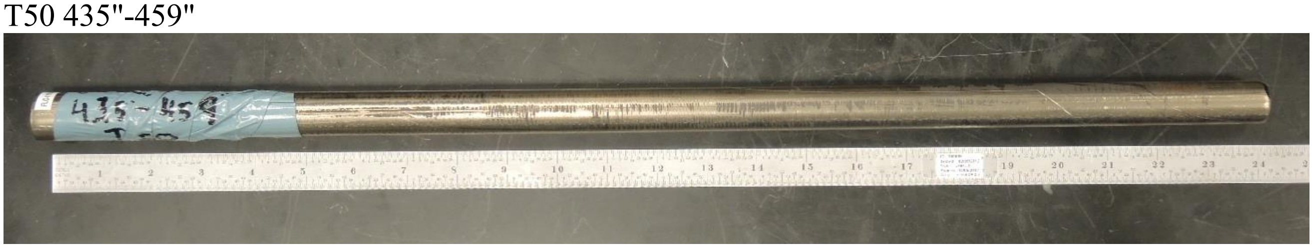


Figure 2: Longitudinal Crack on Segment T53 55"-77"

The longitudinal crack on tube T53 was examined visually and using the stereomicroscope. The crack was relatively straight and continuous and was located along a shallow groove. Adherent deposits or scale partially covered the groove, indicating it was introduced during installation in the condenser.

The crack was located approximately 180° from the seam weld.

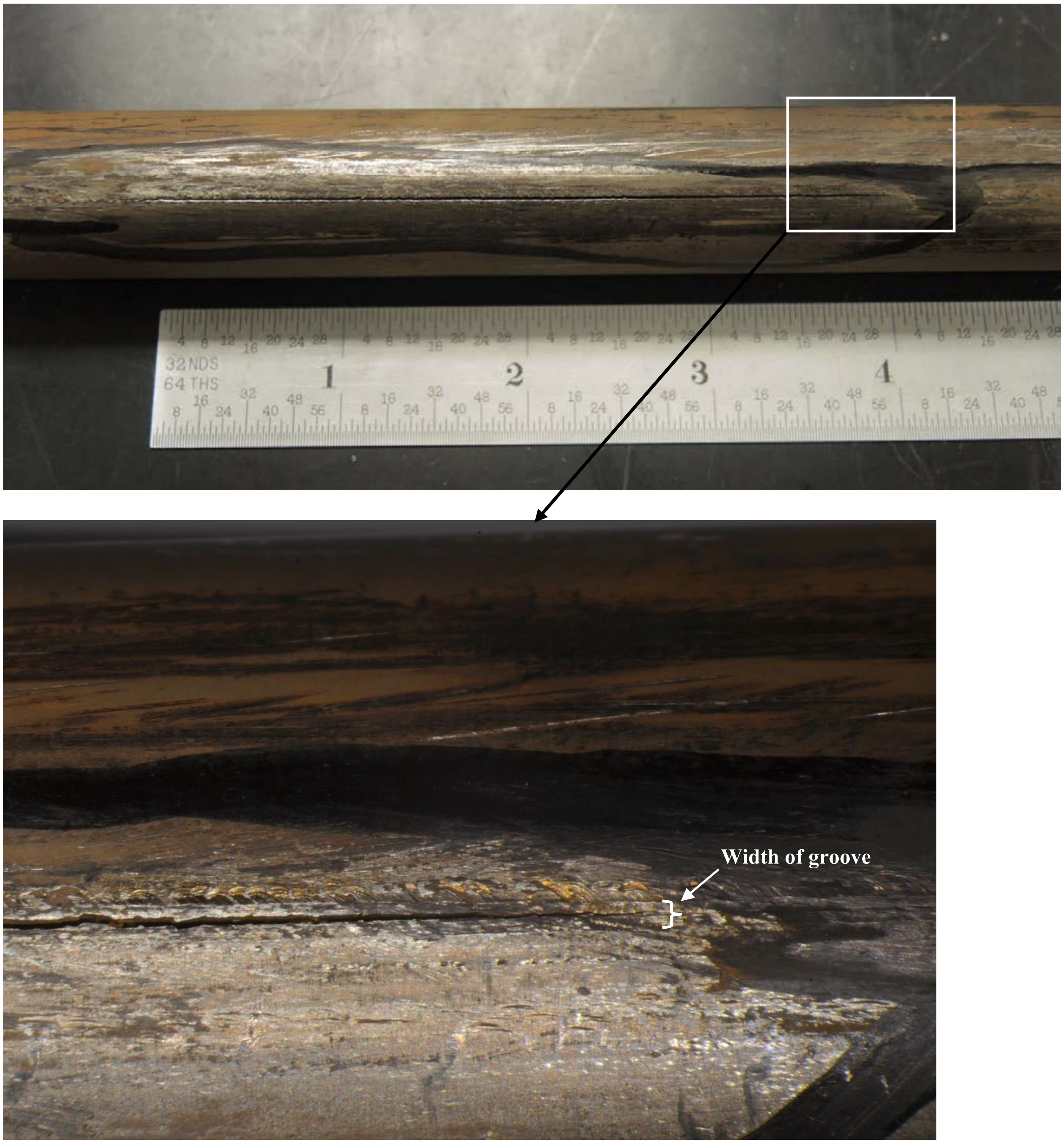
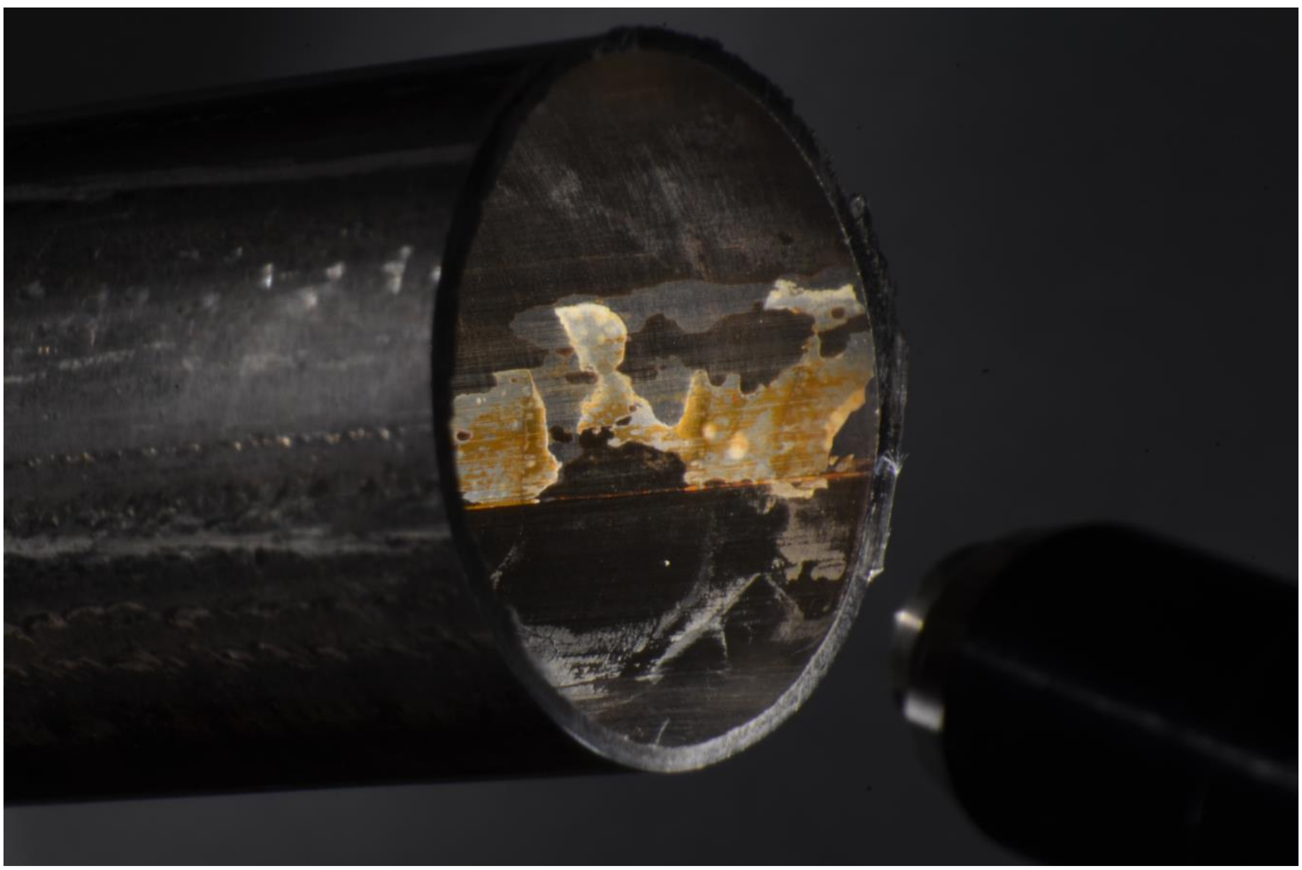


Figure 3: Sectioning of Segment T53 55"-77"

The portion containing the crack was sectioned beyond the crack tips and the crack was split open. Examination of the ID surface was performed. The ID surface exhibited some adherent white and orange deposits, such as shown below. No ID damage mechanisms (pitting, corrosion, erosion) were observed.

Samples of the deposits were analyzed and were consistent with waterborne deposits (Figure 14).



RESIDUAL CIRCUMFERENTIAL STRESS TEST

A 4.75-inch length of the tube was used to estimate the approximate residual circumferential stress according to ASTM E 1928. This specification involves measuring the change in the outside diameter upon splitting the tube longitudinally. The longitudinal split was made along the same radial plane as the crack. Paragraph 6.4 of ASTM E 1928 calls out the following equation to use for calculating the residual stress:

$$\mathbf{S} = \pm \frac{\mathbf{Et}}{\mathbf{1} - \mu^2} \times \frac{\mathbf{D_1 - D_0}}{\mathbf{D_1 D_0}}$$

where:
E – modulus of elasticity, Grade 2 Titanium, Annealed = 14900 ksi[1]
μ - Poisson's ratio, Grade 2 Titanium, Annealed = 0.34[1]
t – wall thickness 180° from split = 0.0271 inch
D_1 - outside diameter after splitting = 0.9104 inch
D_0 - outside diameter before splitting = 0.8714 inch

The estimated residual stress was 22 ksi, with the maximum tensile residual stresses on the tube outside diameter ($D_f > D_o$). The ASTM B 338 (titanium condenser tubing) yield strength requirement for Grade 2 titanium tubing is 40 – 65 ksi. Therefore, the estimated residual tensile stresses in the tube were 34-55% of the tube's yield strength.

1 ASM Metals Handbook, Vol. 2 (10th Ed.), *Wrought Titanium and Titanium Alloys,* p621, 1990

Figure 4: Fractography of Segment T53 55"-77"

The fracture surface was examined using the stereomicroscope. The photo below displays the fracture surface at the crack tip near 63". Ratchet marks, some of which are identified by arrows below, were visible along the OD edge of the fracture surface, indicating the cracking initiated on the OD surface. These marks are formed when competing crack fronts merge, suggesting the 4" long crack was formed by several short cracks that joined. This can also be seen on the left side of the photo, where a short crack (dark surface in circled area) that is approximately 50% through-wall is not connected to the main crack. The dark thumbnail feature at the OD surface is the short crack, and the bright metal represents an intact ligament that was broken in the lab to expose the fracture surface.

Note that the fracture surface of the through-wall crack was not uniformly discolored. This is consistent with a progressive cracking mechanism.

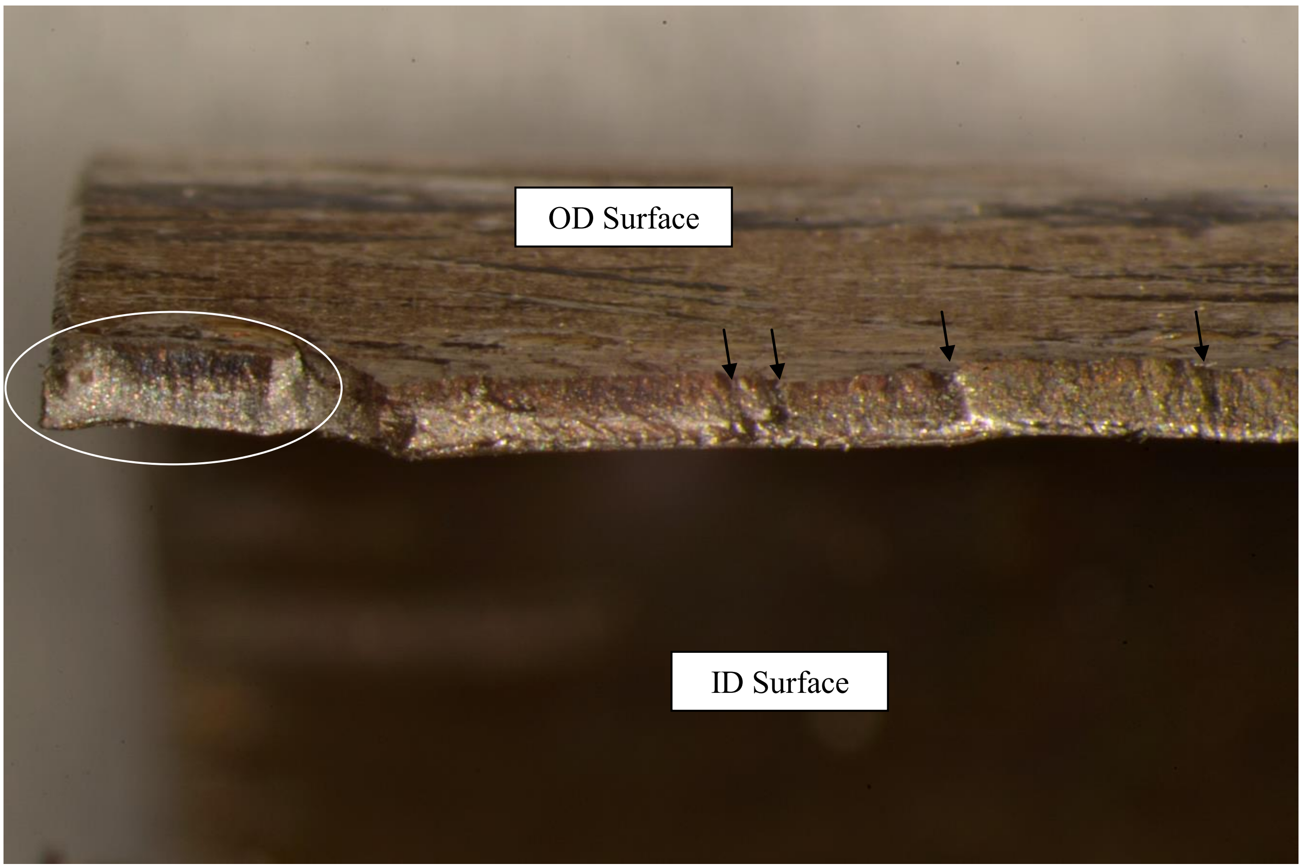


Figure 5: Fractography of Segment T53 55"-77"

The photo below displays fracture surface at the crack tip near 67". This end of the crack displays additional evidence of progressive cracking with multiple, linked cracks. The arrows identify individual cracks that are not linked to the main through-wall crack.

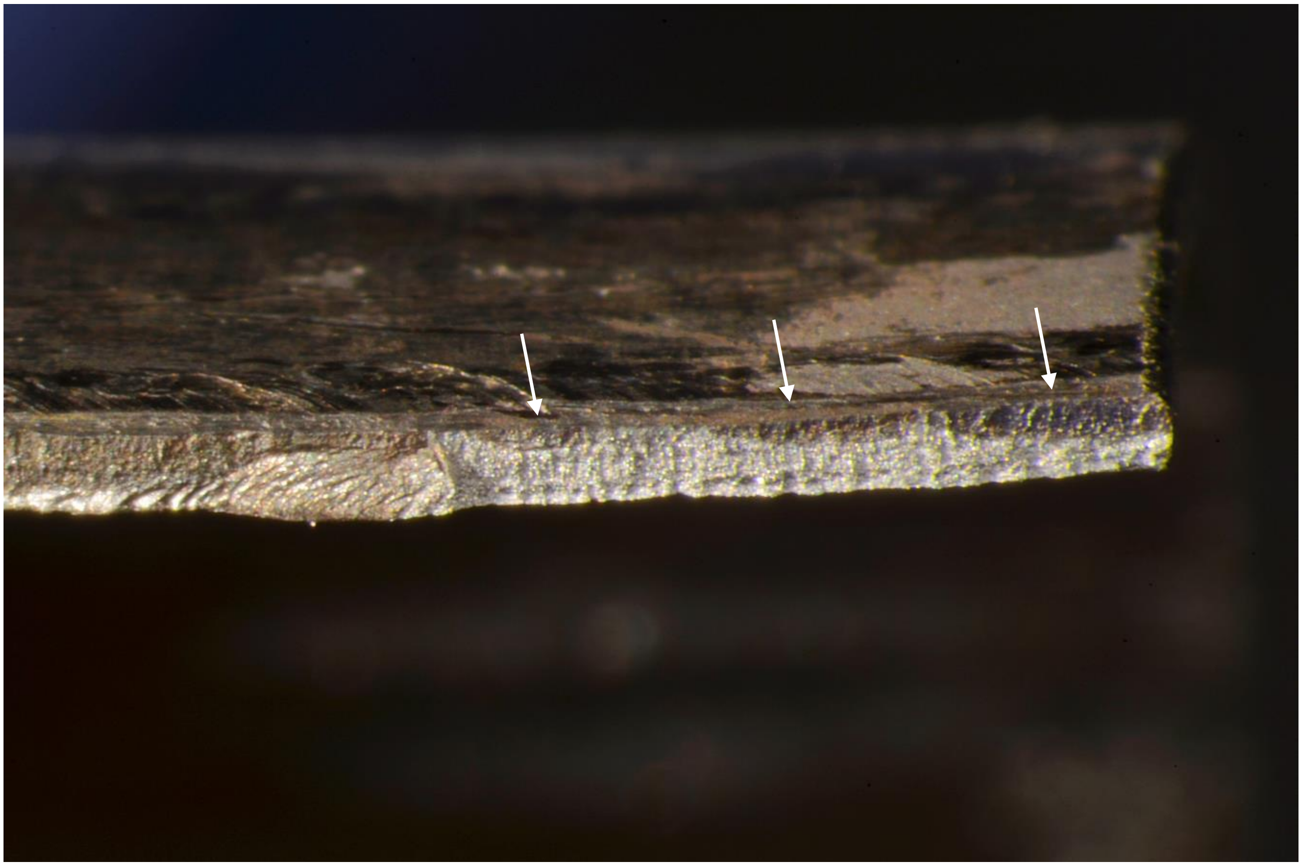


Figure 6: Fractography of Segment T53 55"-77"

A portion of the fracture surface near the crack tip at 67" was examined using the scanning electron microscope (SEM). The SEM photo below is representative of the fracture appearance. The fracture was transgranular and brittle.

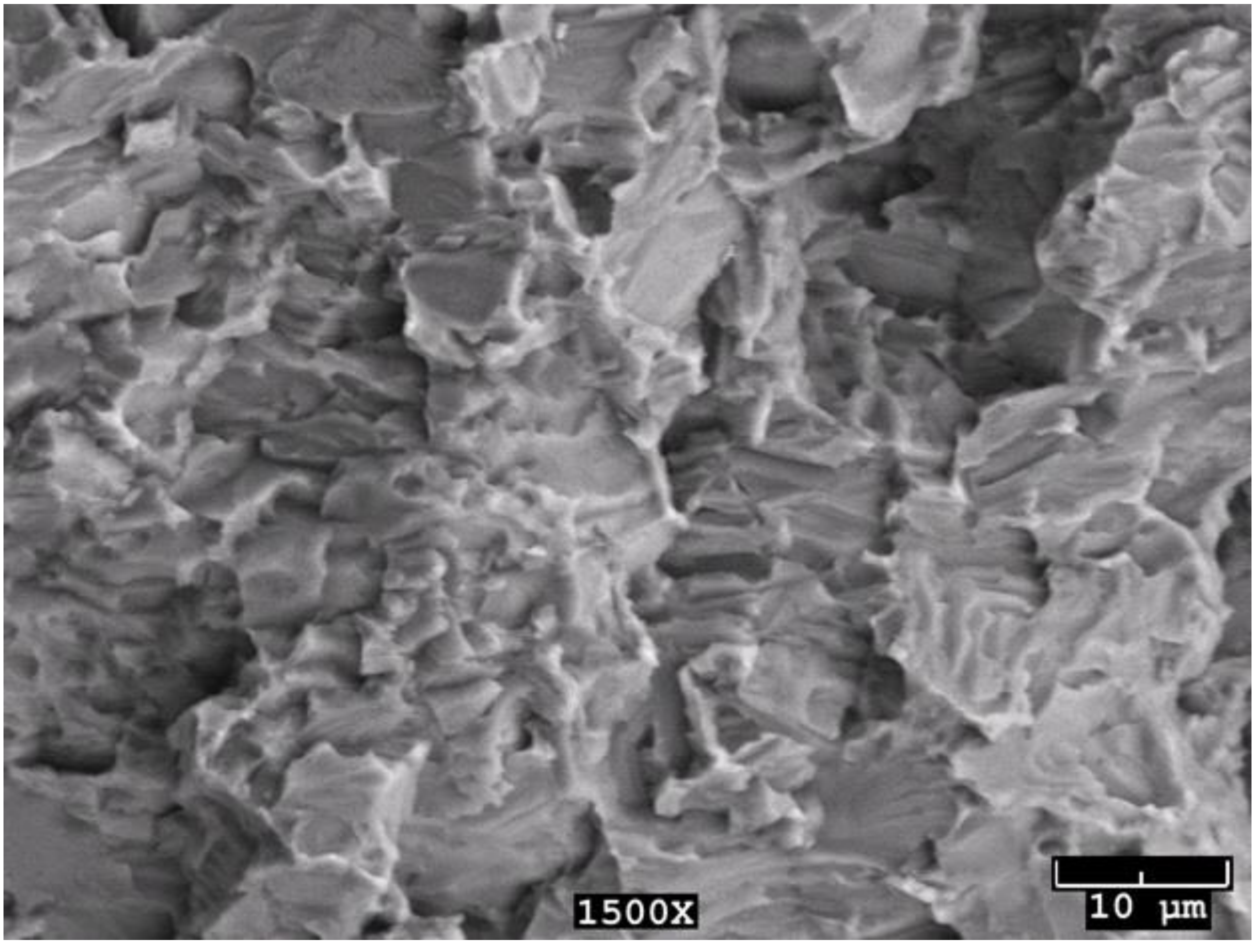


Figure 7: Fractography of Segment T53 55"-77"

The SEM photo below displays the right end of the fracture shown in Figure 5, which is a partially through-wall crack. The dashed line represents the transition from field fracture (above the line) to lab fracture (below the line).

The field fracture was brittle with some secondary cracking near the transition. The lab fracture was ductile. The boxed area is shown in Figure 8.

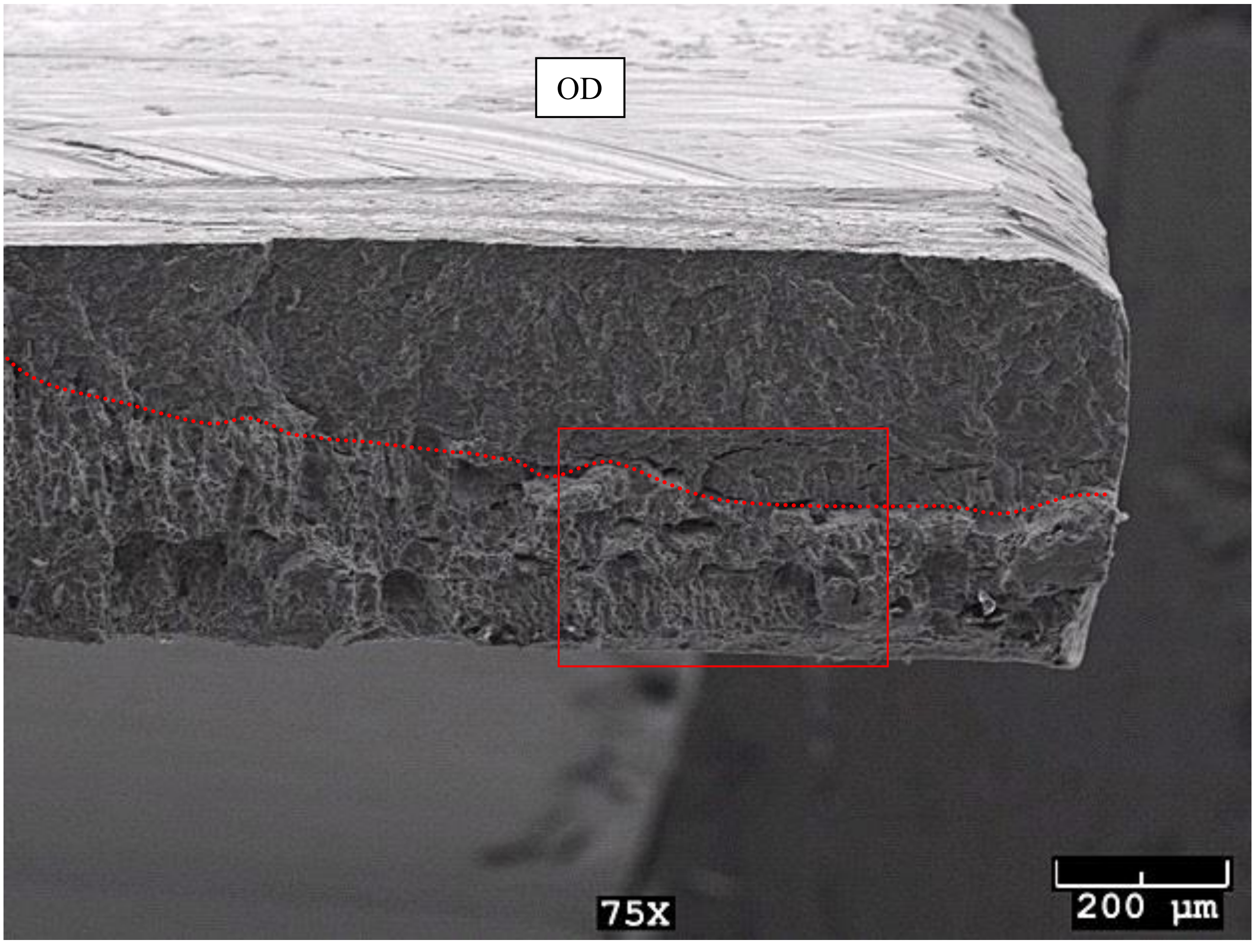


Figure 8: Fractography of Segment T53 55"-77"
A higher magnification image of the transition to lab fracture overload. The lab fracture was ductile.

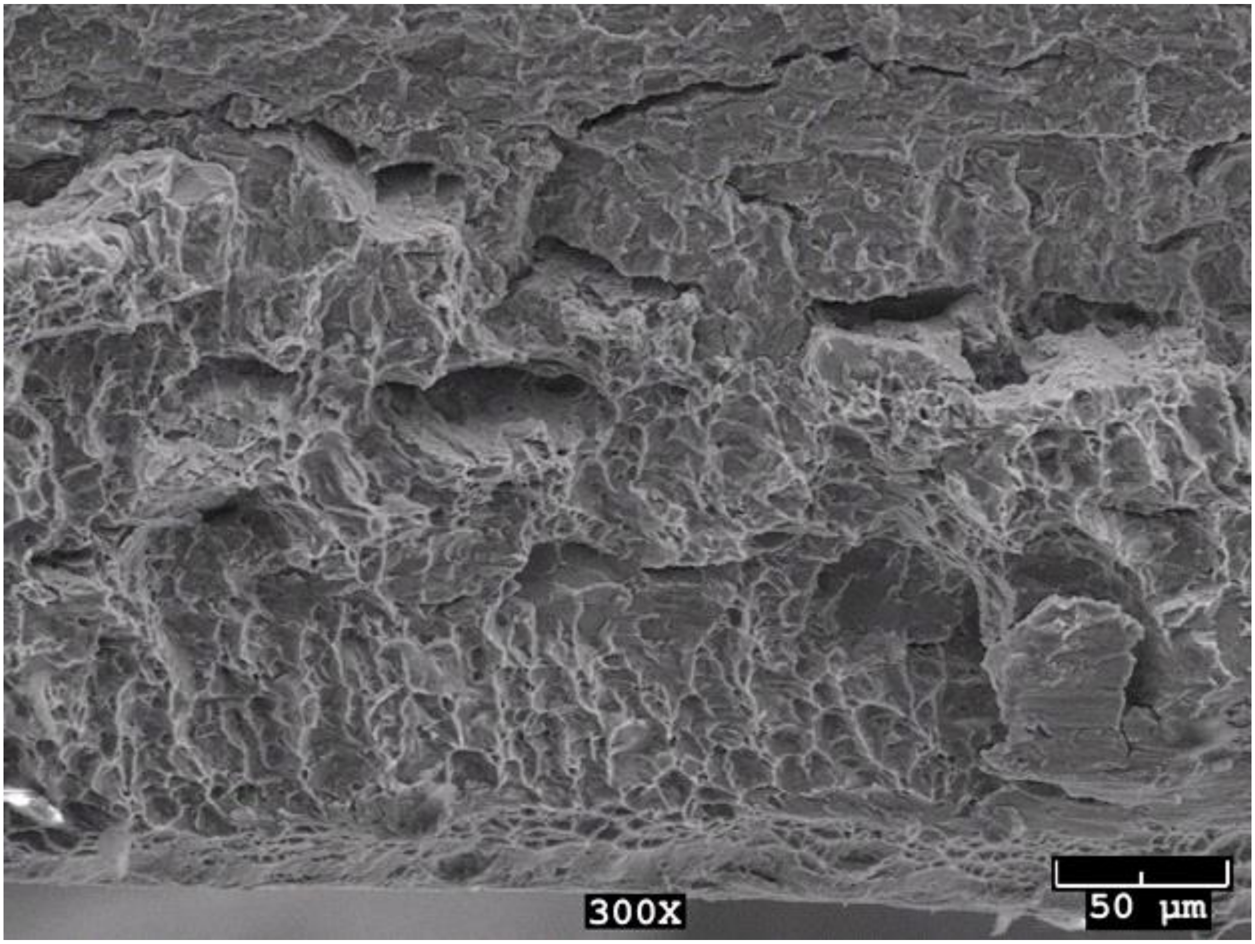
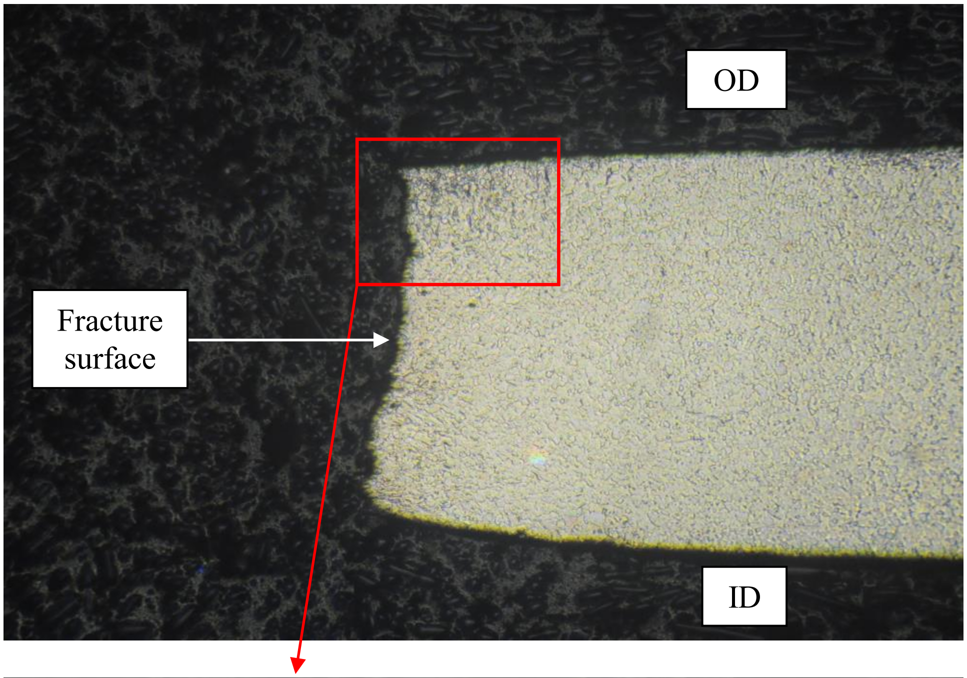


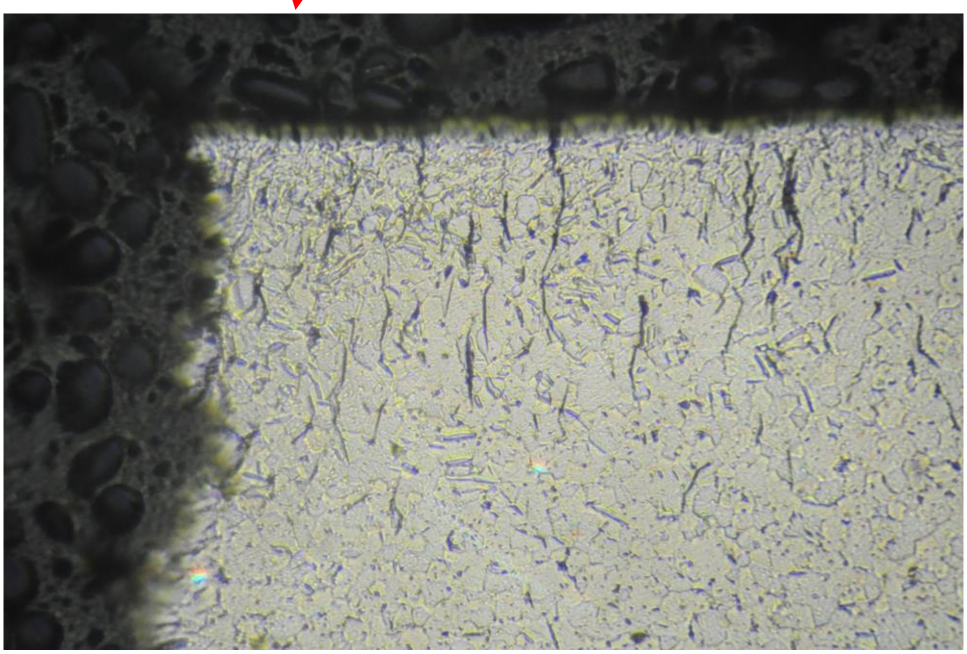
Figure 9: Metallography of Segment T53 55"-77"

A transverse metallurgical sample was prepared near the crack tip at 67". The microstructure exhibited large hydride needles at the OD surface near the crack and along a portion of the fracture surface. No hydriding was evident towards the ID surface. This is consistent with the observation of ductile fracture near the ID on the lab fractured specimen.

Other isolated areas of hydride needle formation were visible on this specimen on the OD surface.



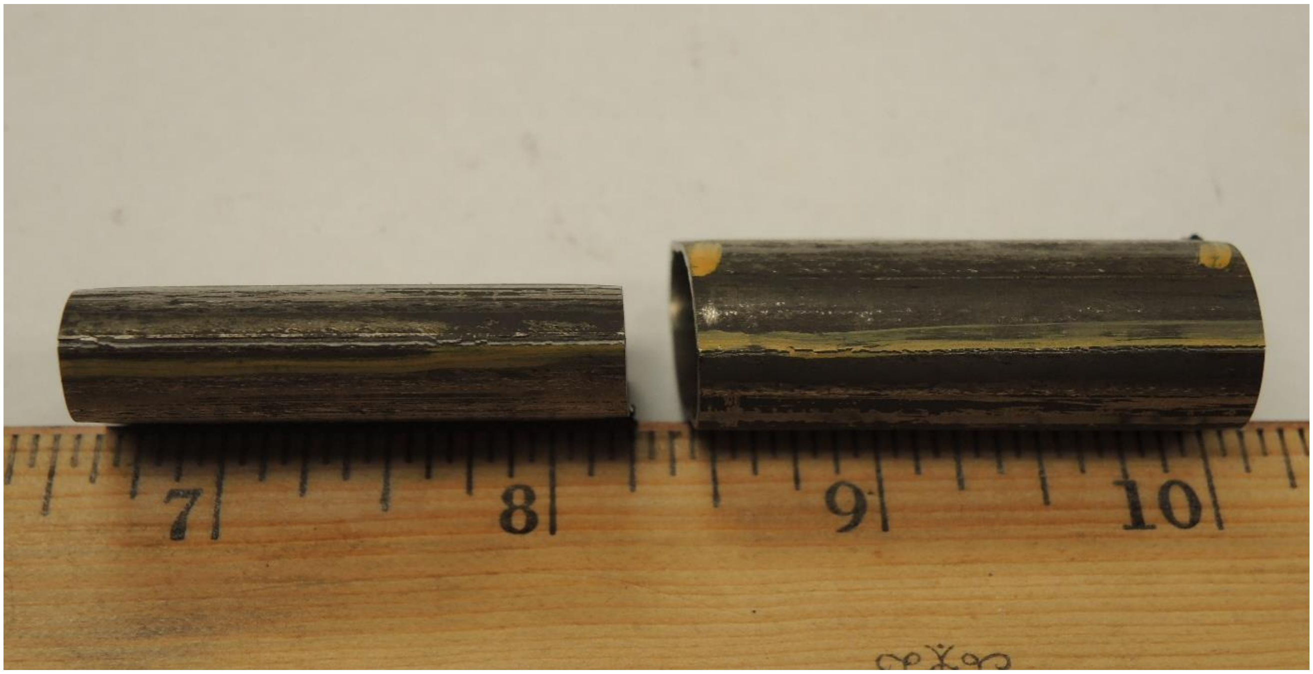
Mag: 90x
Etchant: Kroll's



Mag: 375x
Etchant: Kroll's

Figure 10: Flattening Test of Segment T53 55"-77"

Flattening tests were conducted using guidance from ASTM B338, with the exception that one sample was tested with the weld located at 90° (as required) and the other sample was tested with the weld located at 0°. The intent of the testing was a qualitative determination of the tubing ductility. Cracking was observed on both samples at the 90° and 270° locations (area of maximum tensile stresses). The results are consistent with the observations of hydriding at the failure location and elsewhere around the tube diameter.



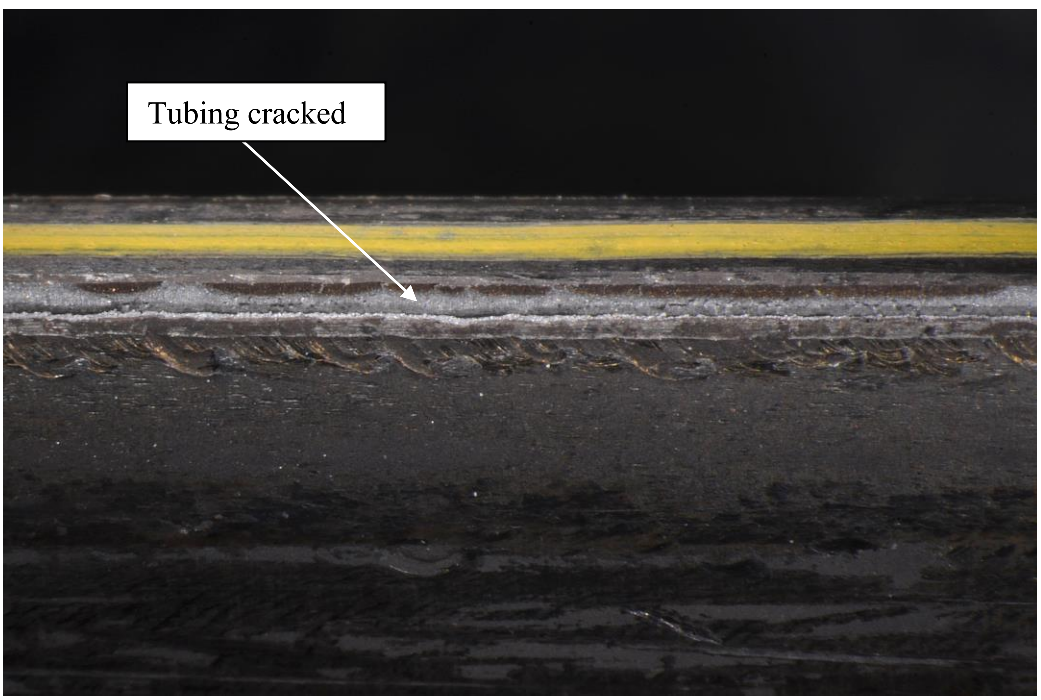


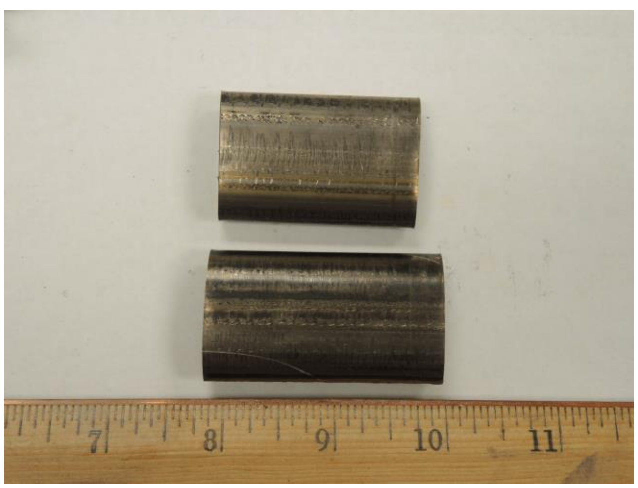
Figure 11: Inspection of Segment T50 435"-459"

Visible dye penetrant testing and stereomicroscope inspection of this tube segment did not identify any notable observations. The station was requested to provide additional information to analyze this tube segment, and the following was offered from the station's ECT Engineer:

1) The center of the original signal identified is at 440" from the outlet tube end
2) The tube section received by Exelon is 435" to 459" as measured from the outlet tube end
3) The signal is about 4" long
4) If a support ring shadow is visible on the tube surface, the maximum signal response should be ~ 6.0" from the center line of that shadow
5) Eddy current saw no signals in this sample or any of the samples for tube 50 after removal from the condenser

Using this information, a 4" long piece centered at 440" was cut from the segment (the dashed lines below designate the cut locations). The ID was examined and no damage was observed. From the 4" long piece, three specimens were prepared: a ring was removed from the center (near 440") for metallography, and the remaining two lengths were used for flattening tests.

Flattening tests were conducted in the same manner used for tube T53. Shallow cracking was observed on the weld fusion line with the weld at 90°. No cracking was observed in the sample with the weld at 0°.



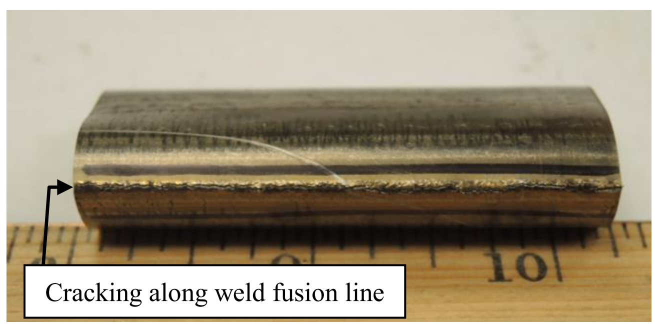
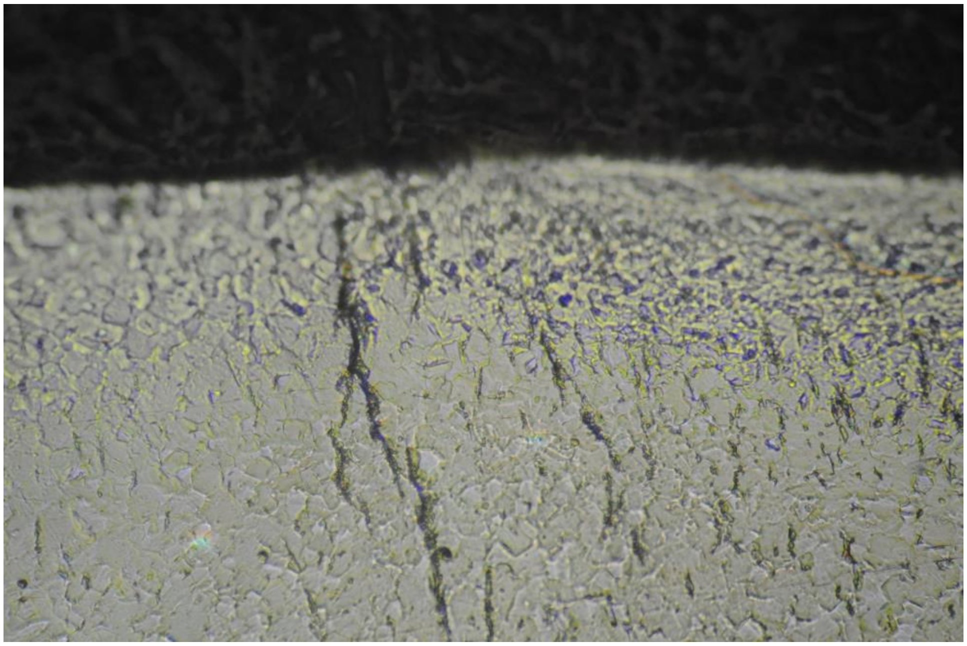


Figure 12: Metallography of Segment T50 435"-459"

A transverse metallurgical sample was prepared near the 440" location, or the center of the original ECT signal. The microstructure exhibited large hydride needles at the OD surface, though to a lesser degree than observed on tube T53.



Mag: 375x
Etchant: Kroll's

Figure 13: Chemical Analysis of Base Metal

The base metal was analyzed using energy dispersive X-ray spectroscopy (EDS). The EDS results were consistent CP titanium.

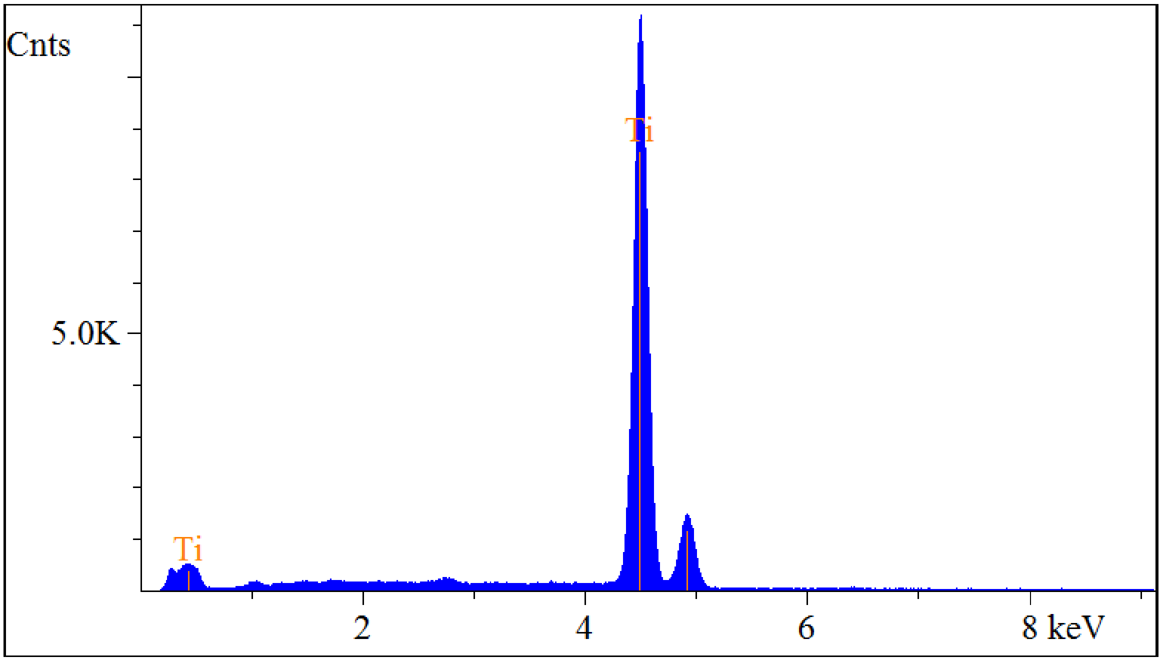
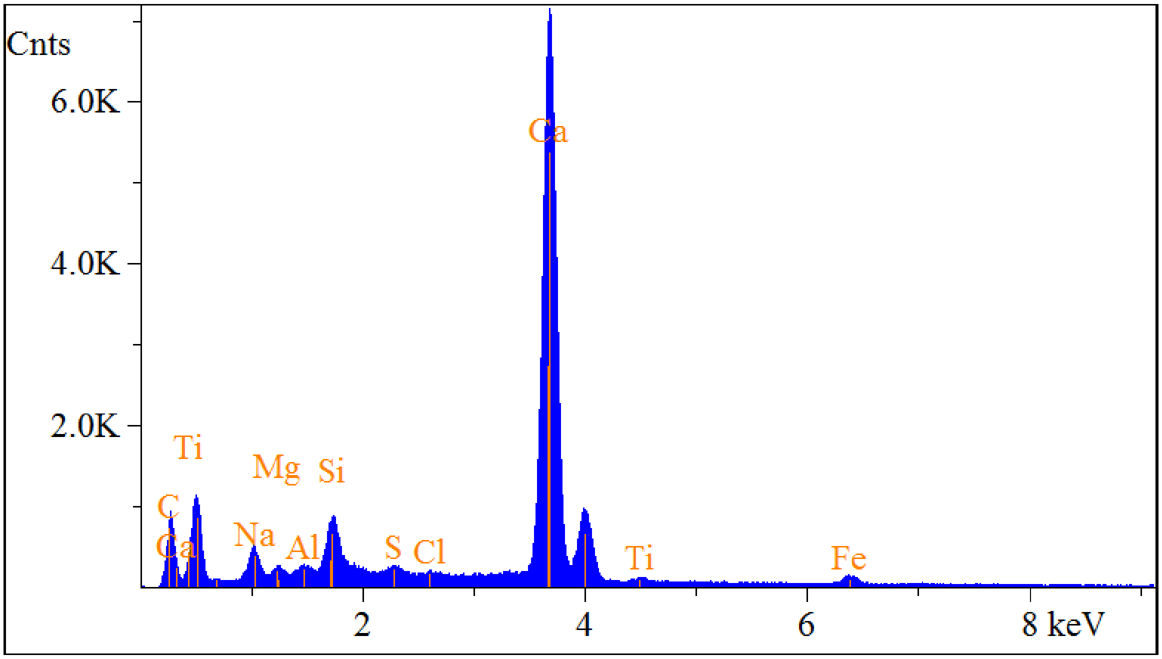
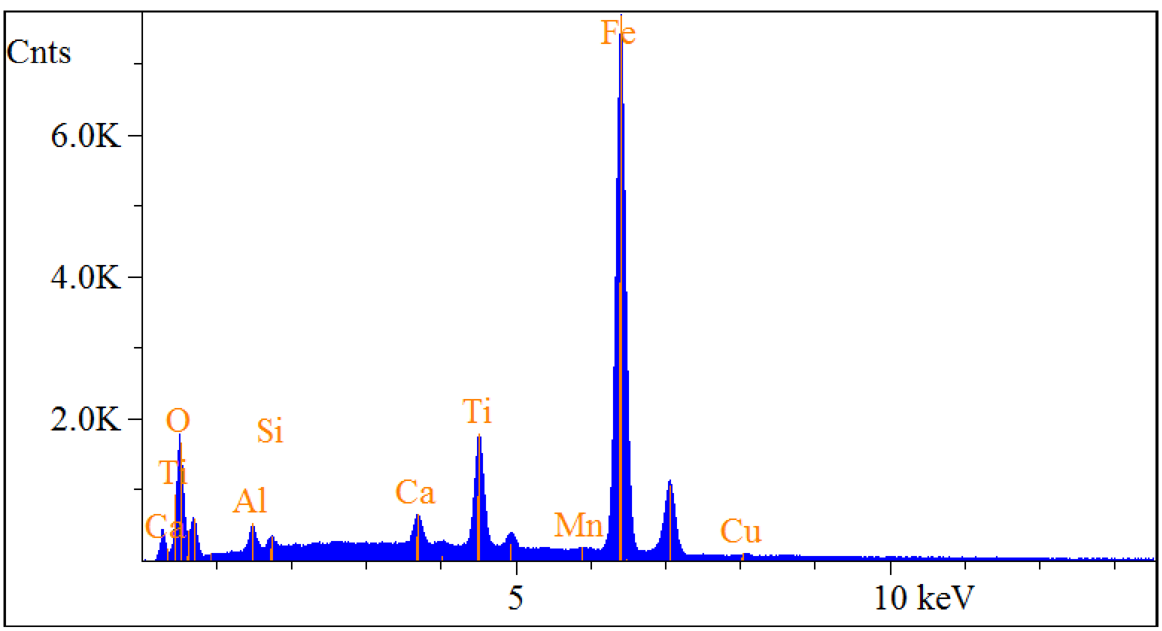


Figure 14: Chemical Analysis of Deposits

The white ID deposit consisted primarily of calcium. Minor amounts of carbon, silicon, aluminum, magnesium, sodium, sulfur, chlorine, iron, and oxygen were also detected. The results suggest the ID deposit consisted of calcium carbonate and waterborne minerals.



The brown OD deposit consisted primarily of iron. Minor amounts of calcium, manganese, copper, aluminum, silicon, and oxygen were also detected. The results were consistent with metal oxides (iron, copper) and minerals (aluminum, silicon, calcium).



Q.

In his 2015 September testimony regarding the February 2015 outage at St. Lucie Unit 2, at pages 6-8, witness Grissette stated that the outage was due to seawater intrusion into a condenser tube. He further stated that FPL would perform detailed testing and remove the suspect tubing during its October 2015 refueling outage, and perform lab testing to determine the root cause and perform any necessary corrective actions to prevent recurrence.

Was the lab testing performed to determine the root cause? If so, please provide a detailed summary of the results of the testing, and a summary of the root cause.

A.

Yes. Refer to Attachment I of Staff's First Data Request No. 1 for the lab results summary.
The root cause evaluation includes an executive summary that provides a summary of the root cause. The leaking condenser tube was the result of pre-1983 installation methods employed during condenser original construction, which caused a minor toolmark on the outer-diameter of a single tube. This toolmark created in original construction resulted in the subsequent tube failure. The defect was undetectable during routine inspections and eddy current testing over the thirty years of condenser service, but it provided a focus for stress concentration. The root cause evaluation is Attachment No. I to this response.

St. Lucie Nuclear Plant

Unit 2 Shutdown for 2A1 Condenser Tube Leak

Event Date: 2/15/2015

CR Number: 2025590

Root Cause Team	Name	Dept/Group
Management Sponsor	Mark Jones	Engineering
Team Leader	Michael Page	Engineering
RC Evaluator	Gay Atkinson	Training
Team Member	Khoury Mains	Engineering
Team Member	Omar Rodriguez	Engineering

Root Cause Evaluator: Gay Atkinson / Gay Atkinson **Date:** 3/3/16
Print/Sign

Management Sponsor: Mark Jones / [signature] **Date:** 3/3/16
Print/Sign

MRC Chair: COFFEY [signature] **Date:** 3/3/16
Print/Sign

Electronic Signature may be obtained by assigning actions in NAMS.
Refer to PI-AA-104-1000 for details.

The root cause process is designed to be self critical to drive improvement. As such, specific organizational and/or programmatic causes within the plant's span of control are identified. The root cause process determines a functional cause and not a legal or contractual cause.

1.0 Executive Summary

Problem Statement:

Unit 2 was shut down due to a sodium excursion in the 2A1 waterbox. Investigation showed that one tube in the lower bundle of the 2A1 waterbox was leaking due to a longitudinal crack initiated from an outer-diameter defect. Chemistry action levels were exceeded due to the sea water in-leakage. The unit remained off line for several days to locate the source of the in-leakage and to perform secondary cleanup.

Narrative of the Event and Response:

On 2/15/2015, St. Lucie Unit 2 was shutdown after condenser chemistry action level limits were exceeded due to seawater in-leakage to the 2A1 condenser hotwell. A Failure Investigation (FIP) Team performed initial investigation in the short notice outage. Based on hydrostatic testing and inspection results, the FIP team directed preventive plugging of a total of 188 tubes in the region of the lower bundle. After secondary cleanup activities were completed, Unit 2 was restarted. In Unit 2 SL2-22 refueling outage (September 2015), all open condenser tubes were cleaned and eddy current tested. Preventively plugged locations in the lower bundle performed as part of the FIP investigation were re-tested and returned to service if no eddy current anomalies were detected. For the 2A1 waterbox, lower bundle tubes R74-T53 and R76-T50 were removed from the condenser. Plugged dummy stubs were installed at the two tube locations. A metallurgy forensics investigation was performed by Exelon PowerLabs and reviewed independently by FPL Nuclear Fleet Materials Program. The leak source of the 2A1 waterbox was verified to be a longitudinal crack on tube R74-T53 only.

Root Cause(s):

RC-1:

Poor workmanship during condenser construction resulted in an outer-diameter tube defect and subsequent tube failure.

- The outer-diameter defect from St. Lucie's R74-T53 tube is concluded to have initiated during tube installation when the condenser was constructed, before Unit 2 started commercial operation in 1983. This is supported by linear scratches seen in the tube and a gouge indication coincident with the crack location evident from the metallurgy analysis.

- Grooving, scratching, gouging, or other outer-diameter tube surface defects are not uncommon from condenser construction on the premise that adequate push force is needed to install the tube through the series of tubesheets and baffle plate supports.

- Poor work practices during tube-push assembly or inadequate cleaning of burrs in the tubesheets and support plates are potential causes by individuals or shift crews pre-1983 when the Unit 2 condenser was assembled. A gouge or scrape of the condenser tube's outer diameter became the initiating precursor to a failure mechanism that propagated from cyclic fatigue and condenser operation.

- INPO event report IER 13-17, *Main Condenser Cooling Water In-leakage*, cites that in several case studies, condenser tube leaks were accelerated by axial scoring during tube installation. INPO concludes that mechanical damage occurred during maintenance or retubing activities in the main condenser as the result of poor workmanship.

- Although the manufacture and installation of the condenser complied with applicable standards at the time of plant construction, programmatic and culture improvements in work execution in the nuclear industry address this workmanship issue.

CC-1:

The service time of the condenser tubes is a contributor for outer-diameter tube failures.

- The failure mechanism is attributed to cyclic fatigue as generated by normal operation, transients, and service time of the secondary plant. This supports that St. Lucie's condenser titanium tubes are approaching the end of their service life.

- The service life of titanium condenser tubes is approximately 40 years based on scientific case studies.

- Unit 1 Main Condenser tubes have operated for 36 years and Unit 2 for 33 years.

- INPO event report IER 13-17, *Main Condenser Cooling Water In-leakage*, supports the fact, that the effects of aging and wear contributes to condenser tube life.

CC-2:

Modern eddy current test technology cannot definitively identify tubes with outer-diameter installation defects.

- Past installation defects in St. Lucie have illustrated non-quantifiable signals in eddy current examinations.

- The failure mechanism does not produce progressive tube-wall thinning. Historical data analysis revealed no change in the signal, further adding to the challenge of detecting tube failures prior to catastrophic rupture.

- The technology available to detect an outer-diameter defect is limited. Therefore, it is possible to have a defect and not be able to identify it.

Corrective Actions:

Area	Category	Corrective Action / Assignment	Responsible	Assignment Type	Due Date
Root Cause (s)					
RC-1: Poor workmanship during condenser construction resulted in an outer-diameter tube defect and subsequent tube failure.	**Equipment**	Plug all St. Lucie condenser tubes that have previously illustrated a non-quantifiable signal or indication (NQS/NQI) in eddy current testing and any other recommended suspect tubes from re-analysis of the Unit 1 and 2 eddy current baseline data from 2015 [Fleet Program Engineering (FPE/ECT)].	**Outage Management** Bill Francis	CAPR	Unit 1: 10/9/2016 SL1-27 RFO WR 94135894 NAMS Assignment 2025590-21 Unit 2: 4/1/2017 SL2-23 RFO WR 94135895 NAMS Assignment 2025590-22
	Equipment / Programmatic	Fleet Program Engineering (FPE /ECT) to coordinate re-analysis and re-acquisition of the Unit 1 and 2 eddy current baseline data from 2015 (SL1-26; SL2-22) to identify potential precursor tube failure signals and potential outer-diameter defect tubes from construction. Provide a list of tubes recommended for preventive plugging to Fleet Thermal Performance Engineering and PSL Engineering.	**Fleet Program Eng (FPE)** Glenn Alexander	CA	5/15/2016 NAMS Assignment 2025590-23

Area	Category	Corrective Action / Assignment	Responsible	Assignment Type	Due Date
	Equipment / Programmatic	Fleet Heat Exchanger Engineer to assess recommended plugging of Unit 1 and 2 Condenser tubes. Plug limits in the condensers have to be evaluated to ensure thermal performance or an adverse condition is not created in the condenser.	**Fleet Engineering (JB)** Ian Watters	CA	6/15/2016 NAMS Assignment 2025590-24
Contributing Cause(s)					
CC-1: The service time of the condenser tubes is a contributor for outer-diameter tube failures.	**Programmatic**	St. Lucie Project Review Board (PRB) to review LTAM PSL-15-0147, *Unit 1 and 2 Condenser Retubing*. Board to decide and, if approved, facilitate funding for development of Alternative Analysis and project execution.	**Projects** Mark Haskin	CA	5/1/2016 NAMS Assignment 2025590-25
CC-2: Modern eddy current test technology cannot definitively identify tubes with outer-diameter installation defects.	**Programmatic**	Develop a written orientation guideline for BOP ECT analysts similar to the one used for Steam Generators. Include a performance demonstration to ensure the analysts can detect and properly disposition the data.	**Fleet Program Eng (FPE)** Glenn Alexander	CA	6/28/2016 NAMS Assignment 2025590-17
	Programmatic	Revise specific guidance for interrogating signals which are believed to be "precursor signals" in the analysis guidelines to enforce the proper attention and rigor is applied during analysis.	**Fleet Program Eng (FPE)** Glenn Alexander	CA	6/28/2016 NAMS Assignment 2025590-16
	Programmatic	Determine the ECT examination scope for Unit 1 SL1-27 and Unit 2 SL2-23 outage given a 50% population limit.	**Fleet Engineering (JB)** Ian Watters	CA	7/28/2016 NAMS Assignment 2025590-18

Area	Category	Corrective Action / Assignment	Responsible	Assignment Type	Due Date
Effectiveness Review					
EFR-1	**N/A**	Perform Effectiveness Review of CAPR in accordance with the reported methodology in the root cause report. Effectiveness Review is to be performed after the Unit 2 SL2-23 refueling outage in spring 2017. Unit 2 SL2-23 outage will occur after Unit 1 SL1-27 outage in fall 2016.	**Fleet Program Eng (FPE)** Glenn Alexander	EFR	4/20/2017 NAMS Assignment 2025590-26

2.0 Report

1. Event Description

At approximately 0300 on 2/15/2015, Unit 2 Annunciator G-20 "Secondary Chemistry Alarm" was received and a significant seawater leak was detected in the 2A1 condenser hotwell. In accordance with procedure 2-AOP-09.03, the steam generator blowdown flow rate was raised, a downpower was performed to 95% power, and the 2A1 Circulating Water Pump was taken out of service to drain the 2A1 waterbox. Chemistry personnel performed secondary sampling in according with 0-COP-05.04 and determined that Action Level 3 limits were exceeded for secondary chemistry.

The Action Level 3 value of a parameter represents the threshold value beyond which data or engineering judgment indicates that rapid corrosion of a significant secondary side component (e.g. steam generators) will occur over the short term. Continued operation of the power plant is not advisable. Procedure 2-AOP-09.03 requires placing the unit in Mode 3 when Action Level 3 limit is exceeded. A rapid downpower was commenced in accordance with procedure 2-AOP-22.01 and steam generator blowdown was further increased and directed to the discharge canal. Due to degrading secondary chemistry trends, Unit 2 was manually tripped from 25% power at 0507 on 2/15/15. The trip was uncomplicated and no other equipment failure occurred.

Annunciator G-20 alarms at 1.0 parts per billion (ppb) sodium concentration, as measured at a Hotwell Sodium Analyzer, or at 1 µmho/cm conductivity, as measured at various conductivity indicating transmitters. Hotwell sodium indication (confirmed from PI data) for the 2A1 hotwell measured high at 10 ppb. Procedure 0-COP-05.04 specifies the Action Level 3 limit at 250 ppb sodium, chlorides or sulfates measured in steam generator blowdown. The chemistry sampling found a concentration of 24 parts per million (ppm) in steam generator blowdown as a basis for Action Level 3. Subsequent monitoring established that the blowdown sodium levels reached a peak value of 75.1 ppm.

A Failure Investigation Team was assembled to determine the source of condenser seawater in-leakage. A partial hydrostatic fill test was performed in the 2A1 waterbox in accordance with 2-NOP-12.05. The 2A1 hotwell was filled to a level of about 8 feet and the tubes were inspected at both the inlet and outlet waterboxes for leakage. Potential leak locations were identified by observation of water flowing from tubes in the lower tube bundle of the 2A1 waterbox. A significant tube leak was identified in tube R74-T53 (lower bundle). Water from the hydrostatic test was found leaking from this tube at the outlet side of the condenser.

Boroscope inspection was performed on seven (7) suspect tubes during the short notice outage. Discovery of an apparent "longitudinal crack" was observed from the boroscope inspection, approximately 5.5 feet from the outlet tubesheet, on tube R74-T53. Tube R74-T53 was removed from service after this discovery by mechanically plugging the two ends of the tube. Eddy current testing was also performed by outside vendor Tricen Technologies in 17 tubes in the vicinity of lower bundle R74-T53. One of the 17 tubes (R76-T50) was found to have a defect measuring 95% thru-wall in depth. All suspect tubes at the time were located on the bottom-center section of the lower bundle in the 2A1 waterbox.

As a conservative measure, a total of 188 tubes in the bottom center section of the lower bundle were plugged. After performing this preventive tube plugging, dimple plug testing was performed for all the remaining tubes in the 2A1 waterbox and no other leaking tubes were identified. After completing the above investigations and testing, the 2A1 waterbox was returned to service on 2/19/2015. In March 2015, the station performed a planned down power on Unit 2 for insurance plugging of the same areas in the 2A2, 2B1 and 2B2 condenser waterboxes.

In Unit 2 SL2-22 refueling outage (September 2015), all open condenser tubes were cleaned and eddy current tested. Preventively plugged locations in the lower bundle performed as part of the FIP investigation were re-tested and returned to service if no eddy current anomalies were detected. For the 2A1 waterbox, lower bundle tubes R74-T53 and R76-T50 were removed from the condenser. Plugged dummy stubs were installed at the two tube locations. A metallurgy forensics investigation was performed by Exelon PowerLabs and reviewed independently by FPL Nuclear Fleet Materials Program. The leak source of the 2A1 waterbox was verified to be a longitudinal crack on tube R74-T53 only.

2. Problem Statement

Unit 2 was shut down due to a sodium excursion in the 2A1 waterbox. Investigation showed that one tube in the lower bundle of the 2A1 waterbox was leaking due to a longitudinal crack initiated from an outer-diameter defect. Chemistry action levels were exceeded due to the sea water in-leakage. The unit remained off line for several days to locate the source of the in-leakage and to perform secondary cleanup.

3. Analysis

A. Analysis Methodology

The following methodologies were utilized to determine causal factors for the condenser tube failure associated with the outer-diameter defect:

- Attachment #2: Events and Causal Factors Chart
- Attachment #3: Support/Refute Diagram
- Attachment #4: Fault Tree
- Attachment #5: Hazard-Barrier-Target Analysis

Summary of Operating History:

Review of past operating history for St. Lucie Unit 1 and Unit 2 condensers indicate that there were two (2) known tube failures attributed to outer-diameter initiated longitudinal cracking (D45, D53). Both events were in the lower portion tube bundles of the Unit 2 Condenser:

1) 2B2 lower bundle tube R76-T54 in January 2006, and

2) 2A1 lower bundle tube R74-T53 in February 2015.

In November 2015, the Unit 2 Condenser experienced a third tube failure event in the 2A2 lower bundle (R72-T36) (D48). The tube failure resulted in a short notice downpower. The cause of this failure is unknown and will be analyzed when metallurgical forensics analysis is performed in the upcoming Unit 2 refueling outage (SL2-23, spring 2017). The suspected tube and several surroundings tubes were plugged. Eddy current results of the tube before the event illustrated a minor internal-diameter indication (IDI) near the tube outlet end (D48).

Unit 1 and Unit 2 Main Condensers are of the same design and material. Unit 1 Main Condenser tubes have operated for 36 years and Unit 2 for 33 years (D31). The total number of condenser tubes in each unit is approximately 48,000 (D56). Approximately 1.8% of the Unit 2 Condenser tubes have been plugged as part the eddy current test program due to degradation (D61). Similarly, 4.5% of the Unit 1 Condenser tubes have been plugged as part the eddy current test program (D61). The difference in quantity of tubes plugged between Units 1 and 2 is the result of severe inside-diameter tube hydriding damage experienced from improper cathodic protection in the 1980s on Unit 1 waterboxes (D43). The service life of titanium condenser tubes is approximately 40 years based on scientific case studies (D60, D62).

No tube failures from outer-diameter initiated defects have occurred on the Unit 1 Condenser. The Unit 1 Condenser was retubed with titanium tubes in 1979 (D31). The original tube materials were aluminum-brass and copper-nickel (D31). A plausible reason why Unit 1 Condenser tubes have not experienced outer-diameter initiated defect failures is possibly the clearing of burrs (i.e., rough edges or ridges) on the tube support baffle plates by the first set of condenser tubes. Without the presence of burrs on the baffle plates, the risk of damaging the outer surface of the titanium tubes would be significantly reduced during retubing installation. Another reason is attributed to the higher number of tubes plugged on Unit 1 condenser from the eddy current test program.

It is important to stress that even though St. Lucie condensers have experienced recurring seawater in-leakage issues; there are three (3) events where catastrophic tube failures have occurred in the past 10 years. As previously stated, the cause of the third event in November 2015 is unknown. This is a critical difference in this investigation compared to other recent condenser issues. Different from abrupt tube failures, previous seawater in-leakage occurred as a result of tube plug failures and leaks through the steam jet air ejector flanges (SJAE) (D58). Specifically, known degraded tubes preventively plugged from eddy current examinations experienced seawater in-leakage to the condenser as a result of the plugs becoming loose: 2A1 waterbox in 2012 and the 2A2 waterbox in 2013. Corrective action for this type of failure resulted in changing all plugs to a titanium double-rubber expandable design and coating over the plugs with epoxy coating. Moreover, inadequate o-ring design of the SJAE flange in the inlet waterboxes experienced recurring seawater in-leakage into the condenser. All SJAE flanges were re-designed to gasket joints as part of the extended power uprate (EPU) outages on both Units 1 and 2.

Failure Analysis of 2A1 Failed Tube (R74-T53):

The failure mode concluded in this root cause evaluation is attributed to an outer-diameter initiated defect resulting in a longitudinal crack of tube R74-T53 based on metallurgy forensics and the Support/Refute analysis (D45). Forensic analysis of the tube concluded a longitudinal crack approximately 180° from the seam weld, outer-diameter initiated, brittle, and appeared to be a progressive cracking mechanism (D45). Investigation of condenser tube failures from longitudinal cracks in the power generation industry and review of scientific papers indicate that this type of failure (longitudinal cracks) is emerging.

The outer-diameter defect from St. Lucie's R74-T53 tube is concluded to have initiated during tube installation when the condenser was constructed, before Unit 2 started commercial operation in 1983. This conclusion is supported by linear scratches seen on the tube and a gouge indication coincident with the crack initiation location evident from the metallurgy analysis (D45). It is further supported by similar claims and conclusions derived by the industry based on other case studies (D09, D43, D45, D53). Common titanium failure modes, such as impact damage, tube-to-tube fretting, tube-to-stake fretting, or steam impingement, were refuted based on the location in the condenser and orientation of the crack on the tube.

Turkey Point (2010) has also experienced outer-diameter initiated longitudinal cracking in their condenser titanium tubes (D54). St. Lucie's longitudinal cracks were located in the lower center region of the lower bundle. Turkey Point's longitudinal crack was located near the center of the bundle. Turkey Point's tube failure was attributed to potential manufacturing or installation defects on the outer-diameter. The Turkey Point longitudinal tube failure occurred due to a poor axial seam weld during manufacturing of the tube. In January 2016, Seabrook also experienced a condenser titanium tube failure resulting in seawater in-leakage (D50). Seabrook's failure was located in the periphery of the upper region of the tube bundle. Although manufacturing or installation defect is a potential cause, the exact failure mechanism is unknown pending outage examination of the tube (D50).

A report from Burns Engineering Inc. cites that grooving, scratching, gouging, or other outer-diameter tube surface defects are not uncommon from condenser construction on the premise that adequate push force is needed to install the tube through the series of tubesheets and baffle plate supports (D09). Burns Engineering also claims that no technology or methodology can accurately predict tube failure unless direct knowledge of location of tube defects during installation 30 years ago is known (D09, D18). This aligns with the eddy current test data of this case where previous examination of the outer-diameter defect in tube R74-T53 only illustrated a non-quantifiable signal which did not meet the plugging logic of the balance of plant eddy current test program. Causal elements of the balance of plant eddy current test program are evaluated further in the *Causal Factor Categorization* section under *Programmatic*.

The metallurgy and industry case studies illustrate that the initiating precursor is the installation defect in the tube's outer diameter surface (D42, D43). In order for a crack to propagate, an initiation point such as an outer-diameter defect must be present. The defect acts as a stress riser and would compound the stresses up to 100 times at that location (D09). On that basis, the internal hydraulic tube pressures at St. Lucie would result in tensile hoop stresses of 20 to 30 ksi, and so could contribute measurably to fatigue cycles and cause longitudinal tube cracks in a tube with outer-diameter installation defects (D09). The ultimate tensile stress of Grade 2 titanium is 50 ksi. Only tensile stresses in the tube can lead to a longitudinal failure. Without the presence of an outer-diameter defect, vibrational stresses would result in a circumferential crack due to fatigue. In the case for R74-T53, cyclic stresses were the catalyst for the crack propagation. As part of EPU modeling of the Unit 2 secondary plant, stresses from normal condenser operation stemming from vibration, steam flows, and other design inputs have been verified to be acceptable (D59). The most probable method of the failure is due to cyclic fatigue as generated by normal operation, transients, and service time of the secondary plant (D43). This strongly supports that St. Lucie's condenser titanium tubes are approaching the end of their service life.

INPO event report IER 13-17, *Main Condenser Cooling Water In-leakage*, cites that in several case studies, condenser tube leaks were accelerated by axial scoring during tube installation. The scoring seeded rupture points that revealed themselves prematurely when the tubes were approaching end of life. These events clearly demonstrate the importance of using appropriate techniques when installing new tubes (D18).

4. Causal Factor Categorization

A. Address each category - People, Programmatic, Organizational and Equipment based on the analysis.

1) People:

As defined in procedure PI-AA-100-1005, *Root Cause Evaluation*, the "People" category focuses on the individual and their span of control. This category equates to individual's performance, and includes use of human performances review / tools, detection of irregularities, and compliance with programs and expectations. Based on the Events & Causal Factor Charting and Support/Refute Analyses, human error is a factor associated with the Unit 2 Condenser tube installation. The tube outer-diameter defects from the 2B2 waterbox in 2006 and 2A1 waterbox in 2015 emerged during tube-push condenser construction (D53). Poor work practices during tube-push assembly or inadequate cleaning of burrs in the tubesheets and support plates are potential causes by individuals or shift crews pre-1983 when the Unit 2 condenser was assembled. Given that the construction of the condenser was performed more than 30 years ago, programmatic and culture improvements in work execution in the nuclear industry are credited to address this specific "people" issue.

2) Programmatic:

As defined in PI-AA-100-1005, the "Process" category focuses on the procedure, organizational and programmatic issues that support people performing activities. These include procedures, instructions, resources, training, etc.

St. Lucie has a balance of plant heat exchanger program that describes the scope and frequency of eddy current testing. The NextEra and St. Lucie balance of plant program utilizes and enforces industry standards and guidelines. Eddy current testing is the established standard test for monitoring and prediction of future tube failure. The eddy current testing performed at St. Lucie uses bobbin type probes suitable for high throughput production testing due to the number of condenser tubes. Similar to the Steam Generated Eddy Current Test Program, array or rotating probe types may be utilized for additional signal analysis.

The NextEra Fleet Program Engineering group provides coordination and oversight of qualified non-destructive examination and eddy current test analysts. Certified analysts execute tube examination using industry standards and administrative controls germane to balance of plant heat exchangers and condensers. Certified analysts assess examination data based on signal characteristics and magnitude.

Tube R74-T53 had a non-quantifiable signal (NQS) at the outlet side of the tube during testing in 2012 and in 2014. Signals that are not consistent with the calibration sample and have not changed in amplitude and presentation based on historical data review are designated NQS. The signal was programmatically assessed to be minor and not flaw-like, and the tube was deemed acceptable for service. The signal was identified, reported, and analyzed by the production technician and lead analyst. The eddy current test signal did not illustrate growth from 2012 to 2014, further demonstrating the tube did not experience tube-wall degradation nor meet standard plugging criteria as assessed by the production and lead examiners (D10, D11, I6).

According to industry standard, a non-quantifiable signal is not a tube defect. This signal type is generally defined as a non-damage signal. Per standards germane to the balance of plant non-destructive examination program (D31, D51, D52), a tube that has a NQS does not meet the logic for plugging criteria and therefore, only warrants follow-up with an analyst if it occurs in a suspicious location or a pattern emerges. The eddy current examination performed in 2014 for tube R74-T53 included a historical analysis to identify trends and patterns. The NQS map for R74-T53 illustrated that there were no notable changes in the NQS signal from previous examinations. Thus, concluding that no follow-up was warranted (D10).

Performance of the eddy current test program in 2012 and 2014 is concluded to not be a causal factor in this investigation. Although the tube failure was verified to be at the location of the known NQS, the standards and administrative controls associated with the balance of plant non-destructive examination program were adequately executed. The certification of the eddy current test production and lead examiners were confirmed to be active prior to performing work on-site. The level of rigor and job quality was appropriate for the signal illustrated at the NQS location. As previously stated, NQS signals are below the threshold of plugging criteria in the industry. The outer diameter tube installation gouge on R74-T53 provided a minor, non-growing, and non-quantifiable signal in the eddy current examination. The examination report from 2014 includes a signal assessment sheet for each confirmed NQS location to assess changes from the previous examination in 2012 (D10). Hence, there was confidence from the production analyst, lead analyst, and the NextEra test coordinator that all NQS signals in 2014 were interrogated adequately. Interview with the NextEra test coordinator and lead oversight who was employed with the company in 2012 and 2014 confirmed that the analysts performed their work correctly with no human performance issues to report (I6).

The challenge for eddy current test technology to detect tube outer-diameter installation defects is concluded as a contributing cause in this investigation. This is further supported by eddy current test technology constraints and industry reports which reaffirm the challenge to detect installation defects in condenser tubes (D09, D18). Currently, there is no accurate method of detecting outer-diameter surface imperfections (gouges) by eddy current tests. The latent condition could lead to future condenser tube failures. As previously reported, past defects resulting from installation imperfections (gouges) in St. Lucie have illustrated non-quantifiable signals in eddy current examinations. The failure mechanism does not produce progressive tube-wall degradation. Interrogation of the signal years later did not reveal a change or growth of the defect, further adding to the challenge of detecting potential tube failures prior to catastrophic rupture.

The optimum preventive action is to plug all St. Lucie condenser tubes that have previously illustrated a non-quantifiable signal and indications in eddy current examination. However, certainty that all defective tubes are being detected by eddy current test technology cannot be confirmed. Enhancements to signal analysis are recommended to augment attention for low range signals which may be precursors of catastrophic tube failures. Actions and enhancements from this event will be further assessed to improve the eddy current test program for the NextEra nuclear fleet.

3) Organizational:

The organizational evaluation is used to determine local and latent organizational issues (underlying causes). The O&P factors are usually contributing causes since they tend to facilitate occurrence, delay discovery or increase the consequences of the event, and the organization is not usually aware of their potential for influencing an event.

No organizational factors that created negative conditions or actions were identified in this investigation. The most notable organizational event relevant to this investigation was the staff re-structure of the nuclear fleet in 2014 with the implementation of NextEra's Project Momentum. Based on the qualification and competency of the NextEra test coordinators, Project Momentum changes to the nuclear fleet are concluded to be non-consequential to the failure of Unit 2's 2A1 lower tube R74-T53.

4) Equipment:

As defined in PI-AA-100-1005, the "Equipment" category focuses on expected operation of components / systems. This category includes equipment degradation / failure and condition that are most commonly due to people and process issues, and design and fabrication issues. The root cause investigation identified a latent failure initiated by tube installation. The metallurgy and industry case studies illustrate that the initiating precursor is the installation imperfection (gouge) in the tube's outer diameter surface (D42, D43). In order for a crack to propagate, an initiation point such as an outer-diameter defect must be present. The defect acts as a stress riser and would compound the stresses up to 100 times at that location (D09). In the case for R74-T53, cyclic stresses were the catalyst for the crack propagation.

B. Based upon the above documentation, categorize the results using the Causal Factor Characterization Matrix below.

Causal Factor Characterization (Each causal factor identified is listed and classified in the appropriate People, Programmatic, Organizational and Equipment categories.)		
Cause Type	**Cause Statement**	**Category**
Root Cause (RC-1)	Poor workmanship during condenser construction resulted in an outer-diameter tube defect and subsequent tube failure.	People
Contributing Cause (CC-1)	The service time of the condenser tubes is a contributor for outer-diameter tube failures.	Equipment
Contributing Cause (CC-2)	Modern eddy current test technology cannot definitively identify tubes with outer-diameter installation defects.	Programmatic

5. Evaluation Attributes

A. Previous Occurrences

Review of past operating history for St. Lucie Unit 1 and Unit 2 condensers indicate that there were two (2) known tube failures attributed to outer-diameter initiated longitudinal cracking (D45, D53). Both events were in the lower portion tube bundles of the Unit 2 Condenser:

1) 2B2 lower bundle tube R76-T54 in January 2006, and

2) 2A1 lower bundle tube R74-T53 in February 2015.

In November 2015, the Unit 2 Condenser experienced a third tube failure event in the 2A2 lower bundle (R72-T36) (D48). The tube failure resulted in a short notice downpower. The cause of this failure is unknown and will be analyzed when metallurgical forensics analysis is performed in the upcoming Unit 2 refueling outage (SL2-23, spring 2017). The suspected tube and several surroundings tubes were plugged. Eddy current results of the tube before the event illustrated a minor internal-diameter indication (IDI) near the tube outlet end (D48).

B. Extent of Condition

The following analysis uses the Same/Similar Technique to further assess the Extent of Condition. This technique applies an approach that tests in five areas. For this event, the condition is identified as:

Unit 2 was shut down due to a sodium excursion in the 2A1 waterbox. Investigation showed that <u>one tube</u> in the lower bundle of the 2A1 waterbox was leaking due to a longitudinal crack initiated from an <u>outer-diameter defect</u>. Chemistry action levels were exceeded due to the sea water in-leakage. The unit remained off line for several days to locate the source of the in-leakage and to perform secondary cleanup.

The scope of the Extent of Condition focuses on titanium condenser tube defects and tubes that exhibit non-quantifiable signals for both Unit 1 and Unit 2 Condensers.

<u>Same Object-Same Defect:</u>

Same Object-Same Defect
<u>Object</u> Equipment: Unit 2 Titanium Condenser Tube Environment: Seawater tube side, steam / secondary shell side People: Not Applicable Organization: Not Applicable Process: Not Applicable <u>Defect</u> Outer-Diameter tube defect

As a conservative measure, a total of 188 tubes in the bottom center section of the lower bundle were plugged. After performing this preventive tube plugging, dimple plug testing was performed for all the remaining tubes in the 2A1 waterbox and no other leaking tubes were identified. After completing the above investigations and testing, the 2A1 waterbox was returned to service on 2/19/2015. In March 2015, the station performed a planned down power on Unit 2 for insurance plugging of the same areas in the 2A2, 2B1 and 2B2 condenser waterboxes.

In Unit 2 SL2-22 refueling outage (September 2015), all open condenser tubes were cleaned and eddy current tested. Preventively plugged locations in the lower bundle performed as part of the FIP investigation were re-tested and returned to service if no eddy current anomalies were detected. For the 2A1 waterbox, lower bundle tubes R74-T53 and R76-T50 were removed from the condenser. Plugged dummy stubs were installed at the two tube locations. A metallurgy forensics investigation was performed by Exelon PowerLabs and reviewed independently by FPL Nuclear Fleet Materials Program. The leak source of the 2A1 waterbox was verified to be a longitudinal crack on tube R74-T53 only.

The outer diameter tube defect from St. Lucie's R74-T53 tube is concluded to have initiated during installation when the condenser was constructed, before Unit 2 started commercial operation in 1983. This is supported by linear scratches seen in the tube and a gouge indication coincident with the crack location evident from the metallurgy analysis. Diameter tube surface defects are not uncommon from condenser construction on the premise that adequate push force is needed to install the tube through the series of tubesheets and baffle plate supports.

Additionally, INPO event report IER 13-17, *Main Condenser Cooling Water In-leakage*, cites that in several case studies, condenser tube leaks were accelerated by axial scoring during tube installation. INPO concludes that mechanical damage occurred during maintenance or retubing activities in the main condenser as the result of poor workmanship.

The corrective action to plug all St. Lucie condenser tubes that have previously illustrated a non-quantifiable signal or indication (NQS/NQI) in eddy current examination and any other recommended suspect tubes from re-analysis of the Unit 1 and 2 eddy current baseline data from 2015 [Fleet Program Engineering (FPE/ECT)] satisfies this Same/Same Extent of Condition analysis.

<u>Same Object-Similar Defect:</u>

Same Object-Similar Defect
<u>Object</u> Equipment: Unit 2 Titanium Condenser Tube Environment: Seawater tube side, steam / secondary shell side People: Not Applicable

Organization: Not Applicable Process: Not Applicable <u>Defect</u> Non Quantifiable Signals or Indication

The purpose of this Same/Similar Extent of Condition analysis was to look for titanium condenser tubes that have previously illustrated a non-quantifiable signal or indication (NQS/NQI) in eddy current examination and any other recommended suspect tubes.

Tube R74-T53 had a non-quantifiable signal at the outlet side of the tube during testing in 2012 and in 2014. Signals that are not consistent with the calibration sample are designated NQS. The signal was programmatically assessed to be minor and not flaw-like, and the tube was deemed acceptable for service.

According to industry standard, a non-quantifiable signal is not a tube defect. This signal type is generally defined as a non-damage signal. Per standards germane to the balance of plant non-destructive examination program, a tube that has a NQS does not meet the logic for plugging criteria and therefore, only warrants follow-up with an analyst if it occurs in a suspicious location or a pattern emerges. However, if an identified NQS tube is plugged preventively, it will eliminate the inherent risk of a tube failure.

The corrective action to plug all St. Lucie condenser tubes that have previously illustrated a non-quantifiable signal or indication (NQS/NQI) in eddy current examination and any other recommended suspect tubes from re-analysis of the Unit 1 and 2 eddy current baseline data from 2015 [Fleet Program Engineering (FPE/ECT)] satisfies this Same/Same Extent of Condition analysis.

<u>Similar Object-Similar Defect:</u>

Similar Object-Similar Defect
<u>Object</u> Equipment: Unit 1 Titanium Condenser Tube Environment: Seawater tube side, steam / secondary shell side People: Not Applicable Organization: Not Applicable Process: Not Applicable <u>Defect</u> Outer-Diameter tube defect /Non Quantifiable Signals or Indication

No tube failures from outer-diameter initiated defects have occurred on the Unit 1 Condenser. The Unit 1 Condenser was retubed with titanium tubes in 1979. The original tube materials were aluminum brass and copper-nickel. Additionally, 4.5% of the Unit 1 Condenser tubes have been plugged as part the eddy current test program due to degradation (D61).

No additional actions are required to satisfy this Similar/Similar Extent of Condition.

C. Extent of Cause

RC-1

Same Object – Same Cause

Object: Unit 2 Titanium Condenser Tube

Cause: Poor Workmanship during Condenser Construction

Poor work practices during tube-push assembly or inadequate cleaning of burrs in the tubesheets and support plates are potential causes by individuals or shift crews pre-1983 when the Unit 2 condenser was assembled. Given that the construction of the condenser was performed more than 30 years ago, programmatic and culture in the nuclear industry has improved in work execution.

No additional actions are required to satisfy this Same/Same Extent of Cause.

Same Object – Similar Cause

Object: Unit 2 Titanium Condenser Tube

Cause: Poor Quality Assurance

Poor work practices during tube-push assembly or inadequate cleaning of burrs in the tubesheets and support plates are potential causes by individuals or shift crews pre-1983 when the Unit 2 condenser was assembled. Given that the construction of the condenser was performed more than 30 years ago, programmatic and culture in the nuclear industry has improved in work execution.

No additional actions are required to satisfy this Same/Similar Extent of Cause.

Similar Object – Similar Cause

Object: Unit 1 Titanium Condenser Tube

Cause: Poor Workmanship during Condenser Construction

Poor work practices during tube-push assembly or inadequate cleaning of burrs in the tubesheets and support plates are potential causes by individuals or shift crews pre-1983 when the Unit 2 condenser was assembled. Given that the construction of the condenser was performed more than 30 years ago, programmatic and culture in the nuclear industry has improved in work execution.

No additional actions are required to satisfy this Similar/Similar Extent of Cause.

CC-1

Same Object – Same Cause

Object: Unit 2 Titanium Condenser Tube

Cause: Service Time of Titanium Condenser Tube

The age of the Unit 2 condenser tube (33 years) contributed to the latent failure that was initiated during installation. The condenser tubes provide a single physical barrier. There is no other physical barrier to provide redundancy, diversity or defense in depth. The tubes in the Unit 2 Condenser were installed in 1983 and are currently 33 years old and approaching their service life. The lack of defense in depth and the age of the tubes reduced design margin (H.6).

CC-1 Corrective Action to perform Condenser Retube satisfies this Same/Same Extent of Cause. Service time/cycles cannot be prevented, but the replacement of tubes resets the service time/cycle clock. St. Lucie Project Review Board (PRB) to review LTAM PSL-15-0147, *Unit 1 and 2 Condenser Retubing*. Board to decide and, if approved, facilitate funding for development of Alternative Analysis and project execution.

Same Object – Similar Cause

Object: Unit 2 Titanium Condenser Tube

Cause: Number of Fatigue Cycles

The age of the condenser tube (33 years) contributed to the latent failure that was initiated during installation. The condenser tubes provide a single physical barrier. There is no other physical barrier to provide redundancy, diversity or defense in depth. The tubes in the Unit 2 Condenser were installed in 1983 and are currently 33 years old and approaching their service life. The lack of defense in depth and the age of the tubes reduced design margin (H.6).

CC-1 Corrective Action to perform Condenser Retube satisfies this Same/Similar Extent of Cause. Service time/cycles cannot be prevented, but the replacement of tubes resets the service time/cycle clock. St. Lucie Project Review Board (PRB) to review LTAM PSL-15-0147, *Unit 1 and 2 Condenser Retubing*. Board to decide and, if approved, facilitate funding for development of Alternative Analysis and project execution.

Similar Object – Similar Cause

Object: Unit 1 Titanium Condenser Tube

Cause: Service Time of Titanium Condenser Tube

The age of the condenser tube (33 years) contributed to the latent failure that was initiated during installation. The condenser tubes provide a single physical barrier. There is no other physical barrier to provide redundancy, diversity or defense in depth. The tubes in the Unit 2 Condenser were installed in 1983 and are currently 33 years old and approaching their service life. The lack of defense in depth and the age of the tubes reduced design margin (H.6).

CC-1 Corrective Actions to perform Condenser Retube satisfies this Similar/Similar Extent of Cause. Service time/cycles cannot be prevented, but the replacement of tubes resets the service time/cycle clock. St. Lucie Project Review Board (PRB) to review LTAM PSL-15-0147, *Unit 1 and 2 Condenser Retubing*. Board to decide and, if approved, facilitate funding for development of Alternative Analysis and project execution.

CC-2

Same Object – Same Cause

Object: Eddy Current Testing Methods

Cause: Did Not Provide Detection of Outer-Diameter Surface Defects

Currently, there is no accurate method of detecting outer-diameter surface defects by eddy current tests. The latent condition could lead to future condenser tube failures. The eddy current results of the tube that failed in February 2015 only presented a NQS. No other signal was present that would direct the recommendation to plug the tube. All NQS signals are reviewed by the technician and the lead analyst to compare the signal from previous data. The processes were in place at St. Lucie to detect signals that would warrant plugging or require further review. It is currently impossible to detect outer-diameter defects that will result in a longitudinal crack. The Eddy Current Test program cannot detect the outer diameter defects and introduces inherent risk.

CC-2 Corrective Actions to develop a written orientation guideline for BOP ECT analysts similar to the one used for Steam Generators and enhance specific guidance for interrogating signals which are believed to be "precursor signals" in the analysis guidelines will enforce the proper attention and rigor is applied during analysis. This satisfies the Same/Same Extent of Cause.

Same Object – Similar Cause

Object: Eddy Current Testing Methods

Cause: ECT Signal Did Not Indicate a Known Defect Signal

Currently, there is no accurate method of detecting outer-diameter surface defects by eddy current tests. The latent condition could lead to future condenser tube failures. The eddy current results of the tube that failed in February 2015 only presented a NQS. No other signal was present that would direct the recommendation to plug the tube. All NQS signals are reviewed by the technician and the lead analyst to compare the signal from previous data. The processes were in place at St. Lucie to detect signals that would warrant plugging or require further review. It is currently impossible to detect outer-diameter defects that will result in a longitudinal crack. The Eddy Current Test program cannot detect the outer diameter defects and introduces inherent risk.

CC-2 Corrective Actions to develop a written orientation guideline for BOP ECT analysts similar to the one used for Steam Generators and enhance specific guidance for interrogating signals which are believed to be "precursor signals" in the analysis guidelines will enforce the proper attention and rigor is applied during analysis. This satisfies the Same/Similar Extent of Cause.

Similar Object – Similar Cause

Object: Eddy Current Testing Review Process

Cause: Did Not Provide Detection of Outer-Diameter Surface Defects

Currently, there is no accurate method of detecting outer-diameter surface defects by eddy current tests. The latent condition could lead to future condenser tube failures. The eddy current results of the tube that failed in February 2015 only presented a NQS. No other signal was present that would direct the recommendation to plug the tube. All NQS signals are reviewed by the technician and the lead analyst to compare the signal from previous data. The processes were in place at St. Lucie to detect signals that would warrant plugging or require further review. It is currently impossible to detect outer-diameter defects that will result in a longitudinal crack. The Eddy Current Test program cannot detect the outer diameter defects and introduces inherent risk.

CC-2 Corrective Actions to develop a written orientation guideline for BOP ECT analysts similar to the one used for Steam Generators and enhance specific guidance for interrogating signals which are believed to be "precursor signals" in the analysis guidelines will enforce the proper attention and rigor is applied during analysis. This satisfies the Similar/Similar Extent of Cause.

D. Safety Culture Evaluation

The safety culture evaluation is addressed in this report indicating the results of the evaluation and the corresponding corrective actions.

The safety culture evaluation form PI-AA-100-1005-F03 was used to evaluate safety culture aspects related to the root cause.

Related Safety Culture Aspect	Alignment with Causal Factor(s)	Comment
H.12 Avoid Complacency: Individuals recognize and plan for the possibility of mistakes, latent issues, and inherent risk, even while expecting successful outcomes. Individuals implement appropriate error reduction tools (QA.4).	**RC-1** (1983) The failure mode evaluated in this root cause was due to an outer diameter initiated defect resulting in a longitudinal crack.	The initiator of the event was an outer-diameter defect which was caused during tube installation in 1983. Thus, creating a latent weakness. Several engineering reports from outside agencies concluded the major contributor was an outer-diameter surface defect that was caused during the installation of that tube in the condenser (D09, D43, D45, D53)
	CC-2 Tubes with outer diameter installation defects cannot be detected by the Eddy Current Testing Program.	Currently, there is no accurate method of detecting outer-diameter surface defects by eddy current tests (ECTs). The tube that failed in February 2015 ECT results only

		presented a Non-Quantifiable Signal (NQS). The processes were in place at St. Lucie to detect signals that would warrant plugging or require further review. It is currently impossible to detect outer-diameter defects that will result in a longitudinal crack. (D52)
H.6 Design Margins: The organization operates and maintains equipment within design margins. Margins are carefully guarded and changed only through a systematic and rigorous process. Special attention is placed on maintaining fission product barriers, defense-in-depth, and safety related equipment (WP.2).	**CC-1** The age of the condenser tube (33 years) contributed to the latent failure that was initiated during installation.	The condenser tubes provide a single physical barrier. There is no other physical barrier to provide redundancy, diversity or defense in depth. The tubes in the Unit 2 Condenser were installed in 1983 and are currently 33 years old.

The results of the Nuclear Safety Culture review indicate that the initiator of the event was an outer diameter defect which was caused during tube installation in 1983. The defect created a latent failure mechanism. Several engineering reports from outside agencies concluded the major contributor was an outer-diameter surface defect that was caused during the installation of that tube in the condenser (D09, D43, D45, D53). The outer diameter defect was not recognized upon installation and the installers did plan for the possibility of mistakes, which created the latent issue, causing inherent risk (H.12).

The age of the condenser tube (33 years) contributed to the latent failure that was initiated during installation. The condenser tubes provide a single physical barrier. There is no other physical barrier to provide redundancy, diversity or defense in depth. The tubes in the Unit 2 Condenser were installed in 1983 and are currently 33 years old and approaching their service life. The lack of defense in depth and the age of the tubes reduced design margin (H.6).

E. Risk/Consequence

There was no actual or potential risk associated with the tube leak event in the condenser from a Personnel, Environmental or Radiological safety perspective.

The actual nuclear safety significance of this event was that a reactor shutdown was prescribed in accordance with plant procedures for secondary chemistry action levels. The shutdown was uncomplicated and all design basis functions were fulfilled.

6. Operating Experience

Internal OE Review

The Events & Causal Factors Charting illustrates previous St. Lucie tube leak events. A NAMS search was also performed for previous condenser tube leaks in the past five years. Keywords: “condenser tube leak” “cndsr”. Similarly, a Documentum search was performed for previous condenser tube leaks in the past five years. Keywords: “condenser tube leak” “tube leak” “sodium”.

One previous occurrence of a longitudinal crack of a condenser tube was identified for St. Lucie condensers. This was documented in AR 480823 (D24). The event occurred in the 2B2 lower bundle tube R76-T54 in January 2006. The affected tube was located in the bottom-center of the lower bundle in the 2B2 condenser. It was plugged and subsequently removed from the condenser for analysis. The analysis determined that two thru-wall longitudinal cracks occurred along a shallow grove running longitudinally along the length of the analyzed sample. The failure was attributed to a longitudinal thru-wall crack approximately 4 inches long originating from a shallow longitudinal groove. The groove potentially originated during tube installation on the exterior surface of the tube. The crack was not in the longitudinal tube seam weld joint and no weld defects were indicated. Supplemental cause evaluation attributed this cracking to hotwell levels maintained too high and corrective action was taken to revise operating procedures (D35).

External OE Review

INPO Level 4 IER 13-17, *Main Condenser Cooling Water In-leakage*, has been reviewed in AR 1870646.

The INPO web OE search (*http://www.inpo.org/xICES*) was used to identify recent condenser tube failures that have occurred since the roll-up review provided in IER 13-17. Keywords: “condenser tube leak”. Relevant events are listed in the table below.

ICES Report	Location/Date	Issue / Cause	Remarks
#331186	Seabrook 1 1/15/2016	Chemistry identified elevated sodium concentrations in all four steam generators on 1/14/16. Investigation determined that the elevated sodium was due to sea water intrusion caused by a small leak in a Condenser tube or tube sheet. The leak was small enough that none of the Chemistry Action Levels were reached. However; after assessing the leak, the decision was made to downpower to approximately 55% to allow repair of the leak. The plant was down powered on 1/17/16 to facilitate the repair.	Cause to be finalized when tube is removed for forensics next refueling outage
#314857	Susquehanna 1 & 2 01/09/2015	Trend in Main Condenser Tube Leaks. No identified cause (tubes to be pulled during their next outage)	Multiple repeat events
#312170	South Texas 1 06/07/2014	Multiple Main Condenser Tube Leaks. ID scoring of tubes due to Cleaning practices	Mechanical scrapers are not used for condenser tube cleaning at St Lucie
#313073	Diablo Canyon 2 08/19/2014	Main Condenser Showed Indications of a Condenser Tube Leak (Salt Ingress). Lagging strap broke off and impacted tubes	Tube failure was secondary damage for other failure.
#312014	FitzPatrick 1 06/01/2014	Forced Outage Caused by Increased Condensate Conductivity and Loss of Condenser Vacuum due to Condenser Tube Leak. Linear extrusion manufacturing defect	St Lucie uses welded seam titanium tubes, not extruded tubes
#311742	Susquehanna 1 03/27/2014	Unplanned Power Reduction Due to Main Condenser Tube Leak	1 of 2 possible causes: steam impingement or vibration.
#306529 #306997 #307359	Fitzpatrick 1 05/24/2013 06/24/2013 08/23/2013	The Plant Performed An Unplanned Down power In Order to Repair a Condenser Tube Leak Caused by wall thinning (age) that resulted in tube rupture	Multiple repeat events due to the same cause (erosion)
#249248	Commanche Peak 2 5/19/2011	Two tubes in the Main Condenser were ruptured due to impacts on the tube exteriors. The locations of the damage as well as the rapid escalation of sodium levels indicated a falling object caused the sudden failure of two condenser tube walls (later determined to be a piece of angle iron used as a support for small bore piping removed from the main condenser shell in a previous refueling outage).	Tube failures attributed to debris impact.

ICES Report	Location/Date	Issue / Cause	Remarks
#246645	Turkey Point 4 12/09/2010	Manual Reactor Trip Due to Condenser Tube Leak At 22:00 on December 9, 2010, Unit 4 had indication (high sodium) of a condenser tube leak. A rapid power reduction to less than 5% with a consequential manual shutdown was commenced in accordance with plant procedures as the sodium levels increased to greater than 250 ppb (action level 3). Chemistry confirmed that the high sodium level was due to salt water intrusion from the 4BN Main Condenser tube bundle. A condenser hydrostatic test was performed and found one tube leak. ECT of the surrounding tubes was made to verify if any object was in contact with the outer diameter of the tube and preventively plugged the surrounding tubes. During the next refueling outage the affected tube was pulled and sent for a metallurgical analysis, the analysis resulted in a tube failure due to low stress high cycle fatigue.	outer-diameter initiated defect resulting in longitudinal crack.

OE Review Conclusions

A. Did our OE program fail?

No. IER 13-17 was assigned as a Level 4 operating experience report by INPO. INPO SOERs and Level 1 & 2 IERs were not found to be applicable to this event; therefore a review of the St. Lucie OE program is not applicable.

B. Are there corrective actions taken previously within the industry that could be considered for correction of our problem?

Based on review of internal and external OE events, this investigation did not conclude any specific corrective action within the industry that would have prevented the event.

From internal OE, prior to the event in February 2015 St. Lucie had only experienced one other condenser tube rupture which required a plant trip on Unit 2 in January 2006. The investigation from 2006 did not conclude a root or contributing cause since that level of investigation was not performed. Corrective actions from the 2006 event focused on condenser hotwell levels since elevated water levels in the hotwell were concluded to have been a notable observation in that investigation. There were no issues with the eddy current test program addressed in that investigation.

As indicated in IER 13-17, numerous events have been reported in which condenser cooling water in-leakage affected power generation. However, there is no industry event that specifically discusses tube installation defects as a non-quantifiable signal in eddy current examination prior to the 2A1 tube failure in 2015. In IER 13-17, INPO advises that utilities perform eddy current testing or an equivalent inspection method on all condenser tubes within a given time period, preferably every 8 to 10 years. St. Lucie's preventive maintenance program for tube cleaning and eddy current test exceeds this frequency by performing 100% examination every 6 years.

7. Lessons Learned

The root cause concluded in this report focused on poor workmanship during condenser construction resulting in a latent tube failure condition. Poor work practices during tube-push assembly or inadequate cleaning of burrs in the tubesheets and support plates are potential causes by individuals or shift crews pre-1983 when the Unit 2 condenser was assembled. A gouge or scrape of the condenser tube's outer diameter became the initiating precursor to a failure mechanism that propagated from cyclic fatigue and condenser operation. Given that the construction of the condenser was performed more than 30 years ago, programmatic and culture improvements in work execution in the nuclear industry are credited to address this specific "people" issue.

The NextEra Nuclear Fleet Safety Handbook promotes excellence in the work that nuclear professionals do each day. A central message from the handbook's core values is "*Do The Job Right The First Time*" (D63). Human Performance (HU) Tools help us maintain positive control of our work situation, ensuring we "*do the job right the first time"* with "*first time quality".*

St. Lucie Station has implemented a *Core Four* approach to error prevention in accordance with PI-AA-103-1000, *Human Performance Error Reduction Tools*. Nuclear Fleet team members should refer to the procedure for additional information on Human Performance Tools.

Four tools have been selected that are vital to HU success:

1. Pre-Job Briefs
2. Self Checking (STAR)
3. Verification Practices
4. Procedure Use and Adherence

Routine Work Action (RWA) 02114701 was generated from this RCE to track reporting of this investigation in *The Daily* publication for St. Lucie Station and to highlight the value of internalizing HU behaviors, processes and procedures that result in us doing the job right the first time.

8. Proof Statement

Problem Statement		Root Cause
Unit 2 was shut down due to a sodium excursion in the 2A1 waterbox. Investigation showed that one tube in the lower bundle of the 2A1 waterbox was leaking due to a longitudinal crack initiated from an outer-diameter defect. Chemistry action levels were exceeded due to the sea water in-leakage. The unit remained off line for several days to locate the source of the in-leakage and to perform secondary cleanup.	**is caused by:**	Poor workmanship during condenser construction resulted in an outer-diameter tube defect and subsequent tube failure.
(Problem Statement)		(Root Cause)

and is corrected by: Plug all St. Lucie condenser tubes that have previously illustrated a non-quantifiable signal or indication (NQS/NQI) in eddy current testing <u>and</u> any other recommended suspect tubes from re-analysis of the Unit 1 and 2 eddy current baseline data from 2015 [Fleet Program Engineering (FPE/ECT)].

(CAPR)

9. Corrective Actions

Area	Category	Corrective Action / Assignment	Responsible	Assignment Type	Due Date
Root Cause (s)					
RC-1: Poor workmanship during condenser construction resulted in an outer-diameter tube defect and subsequent tube failure.	**Equipment**	Plug all St. Lucie condenser tubes that have previously illustrated a non-quantifiable signal or indication (NQS/NQI) in eddy current testing and any other recommended suspect tubes from re-analysis of the Unit 1 and 2 eddy current baseline data from 2015 [Fleet Program Engineering (FPE/ECT)].	**Outage Management** Bill Francis	CAPR	Unit 1: 10/9/2016 SL1-27 RFO WR 94135894 NAMS Assignment 2025590-21 Unit 2: 4/1/2017 SL2-23 RFO WR 94135895 NAMS Assignment 2025590-22
	Equipment / Programmatic	Fleet Program Engineering (FPE /ECT) to coordinate re-analysis and re-acquisition of the Unit 1 and 2 eddy current baseline data from 2015 (SL1-26; SL2-22) to identify potential precursor tube failure signals and potential outer-diameter defect tubes from construction. Provide a list of tubes recommended for preventive plugging to Fleet Thermal Performance Engineering and PSL Engineering.	**Fleet Program Eng (FPE)** Glenn Alexander	CA	5/15/2016 NAMS Assignment 2025590-23

Area	Category	Corrective Action / Assignment	Responsible	Assignment Type	Due Date
	Equipment / Programmatic	Fleet Heat Exchanger Engineer to assess recommended plugging of Unit 1 and 2 Condenser tubes. Plug limits in the condensers have to be evaluated to ensure thermal performance or an adverse condition is not created in the condenser.	**Fleet Engineering (JB)** Ian Watters	CA	6/15/2016 NAMS Assignment 2025590-24
Contributing Cause(s)					
CC-1: The service time of the condenser tubes is a contributor for outer-diameter tube failures.	**Programmatic**	St. Lucie Project Review Board (PRB) to review LTAM PSL-15-0147, *Unit 1 and 2 Condenser Retubing*. Board to decide and, if approved, facilitate funding for development of Alternative Analysis and project execution.	**Projects** Mark Haskin	CA	5/1/2016 NAMS Assignment 2025590-25
CC-2: Modern eddy current test technology cannot definitively identify tubes with outer-diameter installation defects.	**Programmatic**	Develop a written orientation guideline for BOP ECT analysts similar to the one used for Steam Generators. Include a performance demonstration to ensure the analysts can detect and properly disposition the data.	**Fleet Program Eng (FPE)** Glenn Alexander	CA	6/28/2016 NAMS Assignment 2025590-17
	Programmatic	Revise specific guidance for interrogating signals which are believed to be "precursor signals" in the analysis guidelines to enforce the proper attention and rigor is applied during analysis.	**Fleet Program Eng (FPE)** Glenn Alexander	CA	6/28/2016 NAMS Assignment 2025590-16
	Programmatic	Determine the ECT examination scope for Unit 1 SL1-27 and Unit 2 SL2-23 outage given a 50% population limit.	**Fleet Engineering (JB)** Ian Watters	CA	7/28/2016 NAMS Assignment 2025590-18

Area	Category	Corrective Action / Assignment	Responsible	Assignment Type	Due Date
Effectiveness Review					
EFR-1	**N/A**	Perform Effectiveness Review of CAPR in accordance with the reported methodology in the root cause report. Effectiveness Review is to be performed after the Unit 2 SL2-23 refueling outage in spring 2017. Unit 2 SL2-23 outage will occur after Unit 1 SL1-27 outage in fall 2016.	**Fleet Program Eng (FPE)** Glenn Alexander	EFR	4/20/2017 NAMS Assignment 2025590-26

10. Deferral Justification

A deferral justification is required for root cause corrective actions (CAPR and Corrective Action) that are not complete at the time the CR evaluation is reviewed by MRC. The deferral basis for the actions identified within this root cause evaluation is attributed to the performance of condenser and waterbox inspection and maintenance in refueling outages. Justification has been approved by the MRC and assignment dates have been entered accordingly for each corrective action and the CAPR of this root cause evaluation.

11. Effectiveness Review Plan

An Effectiveness Review (EFR) Plan is targeted towards all CAPRs identified in the plan. The Effectiveness Review Plan should include measurable goals, organization responsible for performance of the EFR, and the due date. A successful technique used to develop an effectiveness review plan is called MAST. The MAST acronym stands for Methodology, Attributes, Success Criteria and Timeline.

Effectiveness Reviews are performed after corrective actions have been implemented to verify the corrective actions to prevent recurrence corrected the causes.

RC-1 CAPR:

Plug all St. Lucie condenser tubes that have previously illustrated a non-quantifiable signal or indication (NQS/NQI) in eddy current examination <u>and</u> any other recommended suspect tubes from re-analysis of the Unit 1 and 2 ECT baseline data from 2015 [Fleet Program Engineering (FPE/ECT)].

Method

The method that will be utilized to assess the effectiveness of this CAPR is FPL quality oversight from Fleet Program Engineering (FPE/ECT) of the ECT re-analysis and data acquisition in SL1-27 and SL2-23 outages for the condenser tubes.

Attribute

The attribute that will be used to measure effectiveness will be correct identification and augmented rigor of ECT data. FPL Fleet Program Engineering (FPE/ECT) to ensure that vendor analysis of ECT data is performed in accordance with established standards, guidelines and procedures. In addition, FPL review and/or approval of precursor signals such as non-quantifiable signals and indications should be performed.

Success Criteria

The success criteria is minimization of errors generated by ECT data analysts in the re-analysis of the baseline ECT data in the spring 2016, and the SL1-27 (2016) and SL2-23 (2017) outages.

Timeline

The Effectiveness Review is to be performed after the Unit 2 SL2-23 refueling outage in spring 2017. Unit 2 SL2-23 outage will occur after Unit 1 SL1-27 outage in fall 2016.

12. Attachments

1) Root Cause Charter
2) Events and Causal Factor Chart Analysis
3) Fault Tree Analysis
4) Support/Refute Analysis
5) Hazard-Barrier-Target Analysis
6) Nuclear Safety Culture Analysis
7) Photographs and Illustrations
8) Number of Tubes Plugged

13. Sources Cited

Documents:

D1.	AR 2025590 "2A1 Waterbox Tube/Tube Plug Leak Search", 2/15/2015
D2.	ESOMS Narrative Logs, Unit 2 Operation dated 2/15/15
D3.	Procedure 2-AOP-09.03 Rev. 6 "SECONDARY CHEMISTRY"
D4.	Procedure 0030119 Unit 2 Post Trip Review dated 2/25/15
D5.	Interim Condition #1 Evaluation AR 2025590 dated 2/18/15
D6.	Vendor Manual 2998-2222 Rev. 11 "HEAT TRANSFER EQUIPMENT"
D7.	Interim Condition #2 Evaluation AR 2025590 dated 2/18/15
D8.	Tricen ECT Summary report for PSL Unit 2 2A1 Lower Condenser dated 2/18/15
D9.	Burns Engineering Services CONDENSER TUBE FAILURE REPORT dated 3/9/15
D10.	Anatec report 2A1-MC-LOWER-SL2-21 "Final Inspection Report Main Condenser 2A1 Lower Bundle" dated March 2014
D11.	Anatec report 2A1-MC-LOWER-F12 "Final Inspection Report Main Condenser 2A1 Lower Bundle" dated August 2012
D12.	Specification FLO-2998-093 "Surface Condensers And Accessories", 3/5/1976
D13.	PSL/FPL 2B2 Waterbox Tube Failure, CSI Lab Report PSL-TS-12048 , 3/13/2007
D14.	TEI Unit 2 EPU Steam Surface Condenser Evaluation T28411-2 dated 12 August 2009
D15.	Procedure 0-COP-05.04 Rev74 "Chemistry Department Surveillances and Parameters"
D16.	Procedure 2-ARP-01-G00 Rev23 "Control Room Panel G RTGB-202"
D17.	Procedure 2-NOP-12.05 Rev3 "Condensate Hotwell Operations"
D18.	INPO IER L4 13-17 "Main Condenser Cooling Water In-leakage"
D19.	INPO AR 1870646 "IER L4 13-17, *Main Condenser Cooling Water Inleakage*"
D20.	EPRI TR-112819 "Condenser In-Leakage Guideline"

D21.	Procedure SCEG-030 Rev3 “Condenser and Condenser Waterbox Outage Inspection”
D22.	Burns Engineering, St. Lucie Unit 1 & 2 Condenser Tube Vibration Evaluation, 11/6/2012
D23.	BOP/PSL/PTN-Program Rev 3 “Balance of Plant (BOP) Heat Exchanger Inspection Program”
D24.	AR 480823, “CR 2006-1612 2B2 Waterbox Tube Leak”, 1/20/2006
D25.	AR 1829475, 2A1 Waterbox Tube Leak Disposition, 12/4/2012
D26.	AR 1948066, SL2-21 2A1 Waterbox ECT Disposition, 3/15/2014
D27.	Fleet Procedure ER-AA-115 Rev. 0, “Balance of Plant Heat Exchangers”
D28.	WO 34005088 St Lucie Model PM Work Order for 2A1 Waterbox
D29.	EPRI CS-5942-SR “Proceedings: Condenser Technology Symposium” dated September 1988
D30.	Turkey Point Summary of Unit 4 Condenser Tube Seam Split and Tube Leak 3-12-11
D31.	PCM 78491 “Unit 1 Condenser Retubing”, 1/4/1986
D32.	NDE-1.1 “Eddy Current Examination of Non Ferromagnetic Balance of Plant Heat Exchangers Tubing Using Multi-Frequency Techniques”
D33.	Balance of Plant Heat Exchanger Condition Assessment and Inspection Guide
D34.	Advanced Eddy Current Probes for Improved Flaw Detection and Sizing for Heat Exchanger Tubes
D35.	Procedure 0-CMM-12.01 – Revision 5, “Main Condenser Tube/ Tubesheet Repair”
D36.	AR 02025590, 2A1 Condenser Tube Leak FAR Status Tracking Sheet
D37.	NDE 1.1 – Revision 15, “NDE Manual Examination Procedure: Eddy Current Examination of Non Ferromagnetic Balance of Plant Heat Exchanger Tubing Using Multi-Frequency Techniques”
D38.	NDE 1.5 – Revision 5, “NDE Manual Examination Procedure: Eddy Current Examination For Hydrogen Embrittlement of Titanium Heat Exchanger Tubing Using Multi-Frequency Techniques”
D39.	AR 1878064 NAMS Record, “2A2 Waterbox Potential Tube Leak”, 8/27/2013
D40.	Burns Engineering Report dated 5-29-2006, “St. Lucie Unit 2 Condenser Inspection Report”
D41.	St. Lucie Unit 2 LER L-2006-079 dated 3/17/2006, “Manual Reactor Trip Due to Condenser Tube Leak”
D42.	Daniel S. Janikowski, “Selecting Reliable Heat Exchanger Tube Materials – Factors to Consider,” 5/27/2014
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D44.	Maintenance Rule Functional Failure Evaluation for AR 02025590-01, 3/2/2015
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D47.	Engineering Change 249963 Rev. 1, Condenser Air Removal Upgrades, 2/12/2013
D48.	PSL EACE AR 2093799, 2A2 Condenser Tube Failure Resulting in Unit Downpower, 1/29/2016
D49.	Turkey Point RCE 01600519, “U4 Manual Reactor Trip Due To Condenser Tube Leak”, 12/10/2010

D50.	Seabrook RCE 02103010, "Condenser Tube or Tubesheet Leak," 1/15/2016
D51.	EPRI Technical Report 1013453 - BOP ECT Certification Program
D52.	EPRI Technical Report 1022980 - Guidelines for an Effective HX Program
D53.	AR 482723, "2B2 Waterbox CR 06-1612 Supplemental Engineering Disposition"
D54.	Valtimet Metallurgy Report for 2B2 Tube Failure Report, 5/28/2007
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D57.	HEI Standard for Surface Condensers, 9th Edition, 1995
D58.	Root Cause Evaluation 1656061, Chronic Main Condenser Waterbox Low Level Salt Water Intrusion, 5/30/2011
D59.	EPU Unit 1 Condenser Analysis, "Steam Surface Condenser Evaluation," 4/8/2009
D60.	University of New Orleans Dissertation for Condenser Tube Life Cycle, Utilizing Economic and Environmental Data from the Desalination Industry as a Progressive Approach to Ocean Thermal Energy Conversion (OTEC) Commercialization," December 2013
D61.	St. Lucie Units 1 and 2 Condenser Total # of Tubes Plugged
D62.	Handbook of Corrosion Engineering – Pierre R. Roberge
D63.	INPO SEN 130 – Salt Water Intrusion Caused by Main Condenser Tube Rupture

Interviews:

I1.	2A Waterbox FIP Team Leader
I2.	Chemistry Analyst Interview
I3.	Corporate CSI Engineer Interview (March 2015)
I4.	Corporate Nuclear Materials Engineer
I5.	St. Lucie Design Engineer
I6.	Corporate CSI Engineer Interview (February 2016)

ATTACHMENT #1
ROOT CAUSE CHARTER
(Page 1 of 2)

Root Cause Evaluation Charter - *REVISION*

CR#: 2025590 / CA 2025590-12: Re-assemble an RCE Team to review the tube failure analysis results and issue a final Root Cause Evaluation Report.

Management Sponsor: Mark Jones Department Engineering

Description of the event:

On 2/15/2015 at 0507 Unit 2 completed a rapid down-power and removed the unit from service due to seawater ingress.

Problem Statement:

Unit 2 was shut-down due to a condenser tube leak in the 2A1 waterbox. Investigation showed that one tube in the lower bundle of the 2A1 waterbox was leaking. The seawater ingress resulted in the unit remaining off-line for several days to locate the source of the leakage, and to perform secondary cleanup.

Preliminary Extent of Condition:

The preliminary Extend of Condition is the other 3 water boxes on Unit 2; however, Unit 1 will also be included.

Investigation Scope and Methodology:

The root cause team will review findings from the Failure Investigation Team for this event, PSL operating experience, industry operating experience, inspection results, including eddy current testing results, to determine the cause for the failure.

The team will use approved methods from PI-AA-100-1005 to derive root and contributing cause, including fault tree, hazard barrier target analysis and events and causal factors charting. Other tools will be considered by the team including failure modes and effects and fault tree.

Communication Plan:

The team will support ICES submittal to INPO.

ATTACHMENT #1
ROOT CAUSE CHARTER
(Page 2 of 2)

Team Members:

Management Sponsor:	Mark Jones Dept. Engineering Manager
Team Lead:	Mike Page
Qualified RCE:	Gay Atkinson
Team Members:	Omar Rodriguez
Team Members:	Khoury Mains

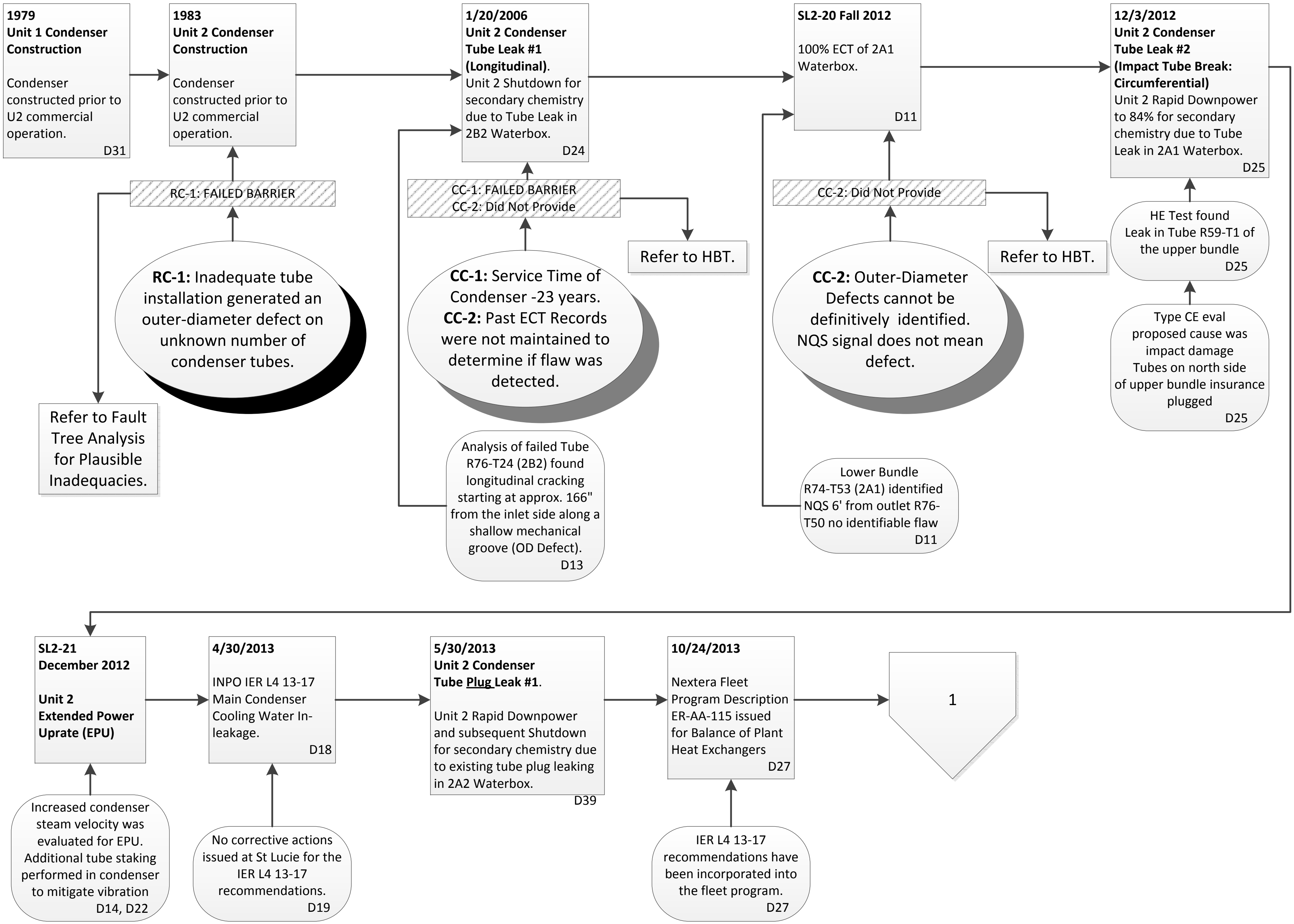
Milestones

CA 2025590-12 (to Complete the RCE) Due Date: 3/7/2016

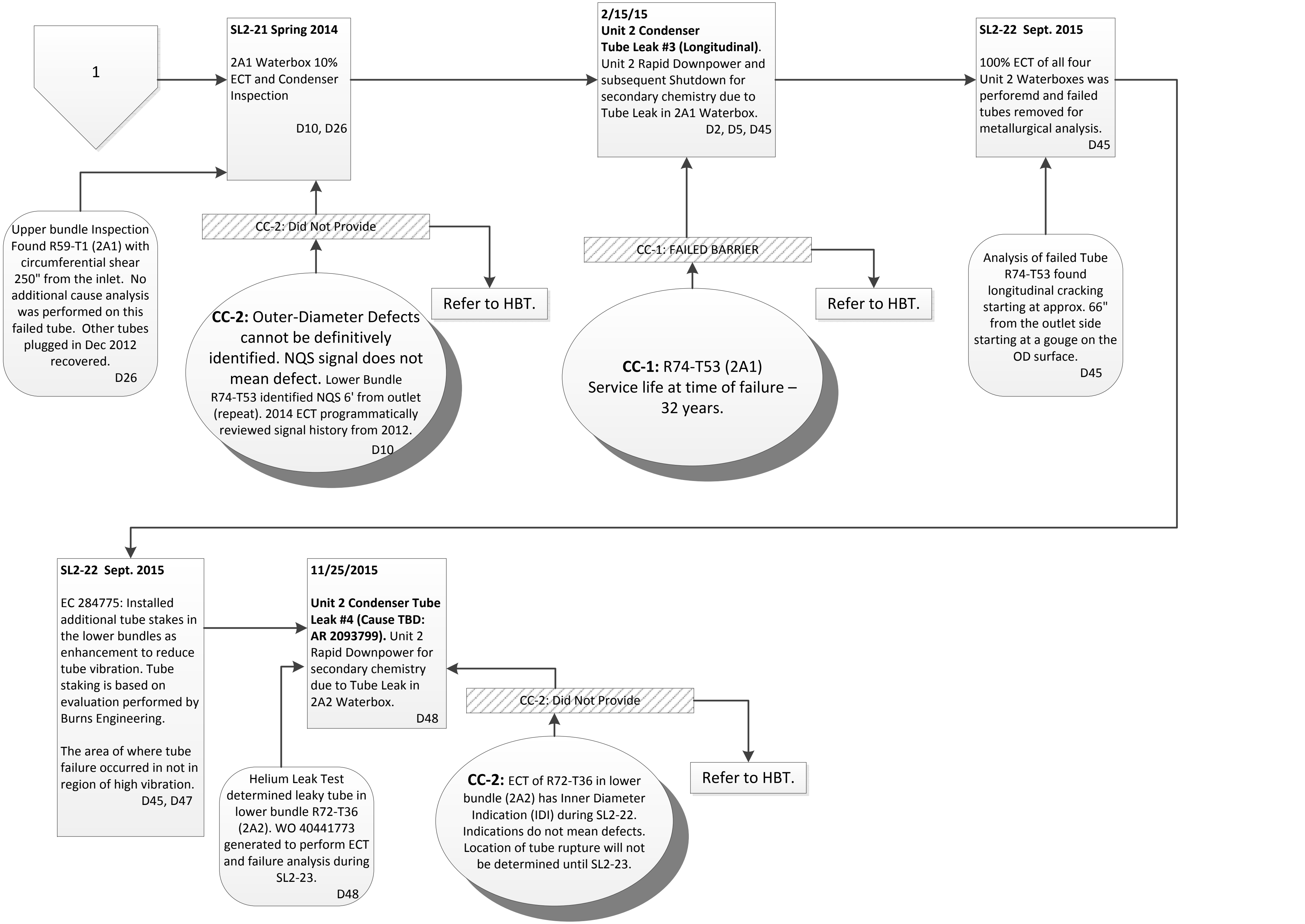
Report provided to CARB for review: 3/3/2016

CARB presentation: 3/4/2016

Attachment #2: Events and Causal Factors Chart

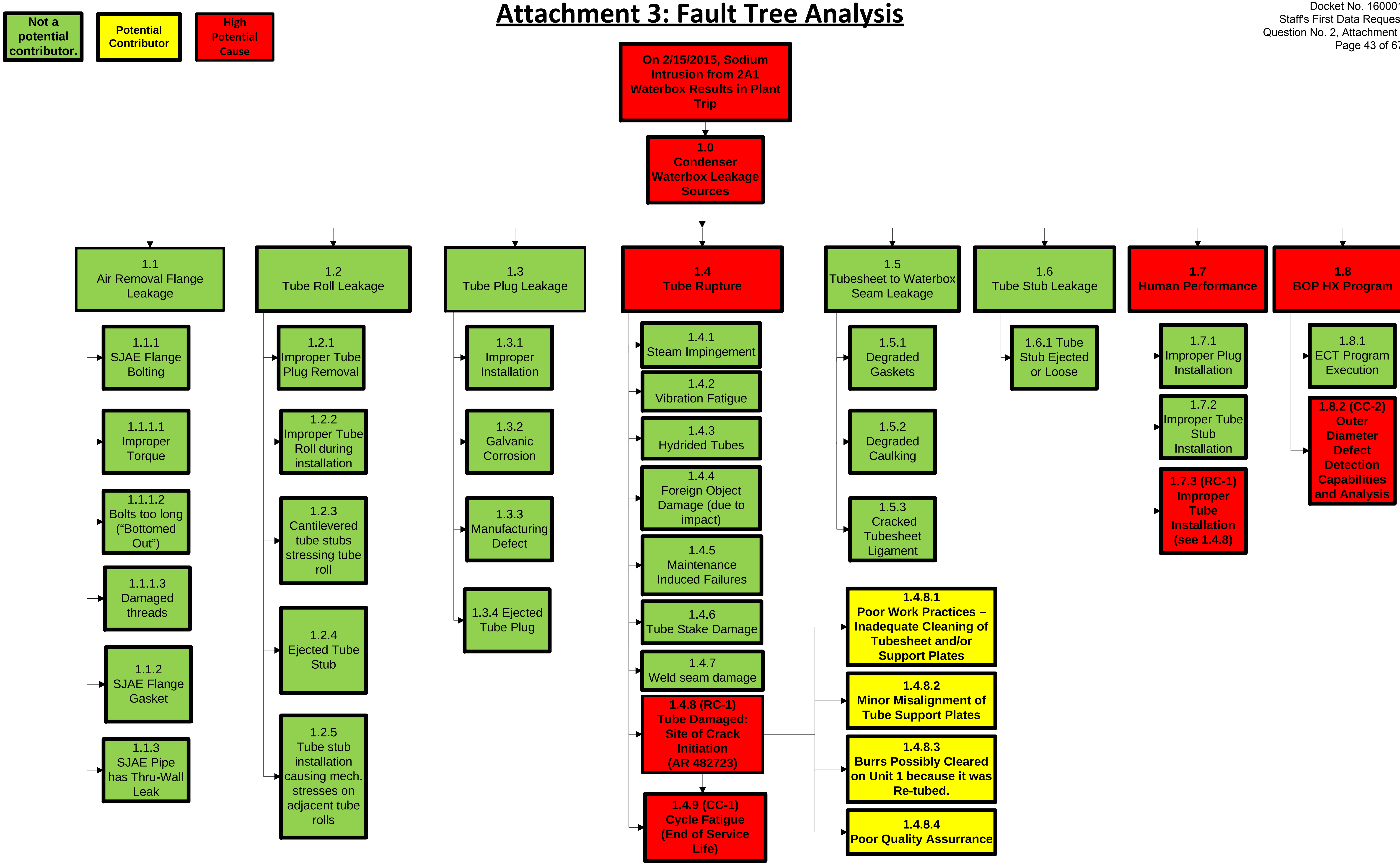


Attachment #2: Events and Causal Factors Chart



Attachment #2: Events and Causal Factors Chart

Attachment 3: Fault Tree Analysis



Attachment #4: Support/Refute for Seawater Leakage Analysis

Support/Refute Matrix

Failure Mode Potential Cause(s)	Supporting Data	Refuting Data	Actions required to Support/Refute	Status
Condenser and Waterbox Seawater Leakage Sources				
1. Thru-Wall Tube Rupture • **Latent Manufacturing/ Installation Issue** ▪ **Tube Damage During Installation**	Metallurgical/Failure analysis concluded the source of failure was a small longitudinal crack initiated at an outer diameter defect caused during installation (D45). Longitudinal failures in tubes result from tensile stresses exceeding their ultimate stress limit. Vibration is not a factor since vibrational stresses act radially and tubes would fail circumferentially. Leakage ceased when the 2A1 CW PP was removed from service. The longitudinal failure was not in the weld seam.	During SL2-22 outage, 100% of each waterbox was eddy current tested and all degraded tubes were plugged. All tubes recording OD damage were plugged as a precautionary measure. All tubes recording ID defects were plugged as a precautionary measure. No evidence of vibrational damage was recorded. Any tubes which could not pass the smaller diameter probe after being cleared by maintenance were characterized as obstructed and were recommended for plugging as a precautionary measure. Previously plugged tubes were verified at both ends. No discrepancies.	Helium leak testing was performed with indicating a small leak from an operating (unplugged) tube. The forensics concluded that a small defect on the outer diameter was the key cause for failure. Based on the metallurgy analysis, FPL Nuclear Fleet Programs and Exelon Power Labs concluded that the cause of the failed tube was tube damage during installation (D45).	**Root Cause - 1**
2. Air Removal Flange Leakage	Flanges have previously been the source of seawater leakage. Following rapid downpowers and plant trips, seawater leakage increases unless flanges are coated. Leakage ceased when the 2A1 CW PP was removed from service.	The flanges were modified in SL2-20 as part of EPU. A different coating material was utilized to prevent cracking and aging in the coating material. Initial report from the field (AES-helium testers) indicated the SJAEs are not the leakage source. In addition, not a significant	Helium Leak Testing did not indicate a leak in the air removal flange.	Not a Cause

Attachment #4: Support/Refute for Seawater Leakage Analysis

Failure Mode Potential Cause(s)	Supporting Data	Refuting Data	Actions required to Support/Refute	Status
		coating degradation around the flanges; minor coating cracks were found but does not appear unusual.		
3. Tube Roll Leakage	Following the SL1-24, a tube stub was pulled into Unit 1's condenser from the 1A2 outlet waterbox and resulted in significant seawater intrusion. A Root Cause Evaluation was completed and concluded the tube stub ejections were caused by the forceful tube plug removal methods that were used. This method used to remove the plugs loosened up the tube stub by damaging the tube to tube sheet roll.	No apparent damage to the tubesheet was noted during inspection. All tube plugs were tight and coated. Tubesheet pressurization tests were performed during the outage and no leaks were observed on the waterbox side. This indicates that there was no leakage into the integral tubesheet system. Tube roll leakage is not likely based on the integral tubesheet mod to pressurize the system from condensate. Pressure for the integral tubesheet system is higher than CW PP discharge pressure. The mod provides an even pressure distribution across the integral tubesheet. It would take significant leakage and poor tube rolls on both sealing surfaces of the tubesheet in order to have saltwater intrusion into the condenser.	Pressurize the tube sheet fill with air and snoop the tube rolls in the waterbox if possible (not practical online). Enter the waterbox and look for degraded Plastocor coatings (performed during initial Eng. Inspection with no damage noted). Shaving Cream Test can be used to help identify tube roll leaks.	Not a Cause

Attachment #4: Support/Refute for Seawater Leakage Analysis

Failure Mode Potential Cause(s)	Supporting Data	Refuting Data	Actions required to Support/Refute	Status
4. Tube Plug Leakage	A loose tube plug in a degraded tube location may have introduced seawater to the condensate system. Leakage ceased when the 2A1 CW PP was removed from service.	All tube plugs were coated with Plastocor in previous outages.	Tube plug visual inspection and accountability was performed. All tube plugs were accounted for. Helium leak testing was performed with indicating a small leak from an operating (unplugged) tube. Tubes plugs were checked for tightness - SAT.	Not a Cause
5. Tube Plug Ejection on Degraded Tube	This only applies to plugged tubes that had through-wall leakage. PSL has had ejected tube plugs in the past. Leakage ceased when the 2A1 CW PP was removed from service.	Trend data may be characteristic of tube ejection for rows under water. S/G contaminants would have increased drastically (spike), quickly reached a peak value. Tube has to have a pre-existing pathway (hole) for seawater to be drawn into the condenser, which makes it difficult to build up pressure if there is a hole.	Tube plug visual inspection and accountability was performed. All tube plugs were accounted for. Helium leak testing was performed with indicating a small leak from an operating (unplugged) tube. Performed tube plug verification with post SL2-22 ECT maps.	Not a Cause
6. Leak from the Tubesheet to Waterbox seam	This joint has caused issues in the industry by seawater leaking around the tubesheet and back into the condenser through the bolt holes. Waterbox welds could potentially have degraded the gaskets allowing this leakage path. There is a residual amount of seawater left in the	In SL2-20, a different coating material was utilized to prevent cracking and aging in the coating material in this area. Initial engineering inspection documented no apparent dame to tubesheet seam.	Helium testing and visual inspected did not indicate any leakage path or material degradation on the seam.	Not a Cause

Attachment #4: Support/Refute for Seawater Leakage Analysis

Failure Mode Potential Cause(s)	Supporting Data	Refuting Data	Actions required to Support/Refute	Status
	bottom of the Inlet Waterbox due physical geometry of bowl and drain valve being closed. Leakage ceased when the 2A1 CW PP was removed from service.			
7. Tube Stub (Tubesheet Plug) Leaking	Tube stubs are installed as tubesheet plugs due to the integral tubesheet system. A tube stub was ejected while pulling vacuum for the first time after Unit 1 SL1-23. A large amount of seawater contamination occurred. Tube stubs were not replaced on Unit 2 during SL2-22. Leakage ceased when the 2A1 CW PP was removed from service.	Tube stub leakage would indicate major seawater leakage. Corrective actions from previous tube stub failures included utilizing a Retubeco dummy tube with seal welded titanium plugs. Eccentricity measurements prior to and post-tube roll ensure tube roll is satisfactory.	See the actions for tube roll leak and a tube plug leak.	Not a Cause
8. Cracked Tubesheet Ligament	This is very difficult to determine because Plastocor coatings have to be removed and a tubesheet integral groove pressurization test would be required to validate. A ligament was discovered cracked in the Unit 1 1A1 waterbox during repairs. Leakage ceased when the 2A1 CW PP was removed from service.	This would have been a chronic leak since plant startup from SL2-22.	Tubesheet pressurization test with coatings removed. Check the tubesheet flush water for contamination. Will require extensive effort to locate if coating removal is required.	Not a Cause

Attachment #5: Hazard-Barrier-Target Analysis

Target	Hazard	Barrier	SPS	Conclusion	Comments
Secondary Chemistry Secondary Components	Sea Water In-Leakage	Condenser Tubes (*Prevention*)	1	**Failed Barrier** **CC-1**	The condenser tubes provide a single physical barrier. There is no other physical barrier to provide redundancy, diversity or defense in depth. Thus <u>each of the 47,840 tubes in the condenser is a single point vulnerability</u>. This single barrier is restated as a Target to be protected below and reviewed for barriers below. The service life of titanium condenser tubes is approximately 40 years based on scientific case studies (D60, D62).
		Chemistry program and procedures (*Prevention*)	4	Did Not Fail	The chemistry action levels are established in procedures to protect secondary components from corrosion. These are risk informed actions that balance continued plant operation in the short time against equipment life as well as safety consequence (i.e. SG tube rupture) considerations. The unit shutdown due to a tube leak was ultimately a choice of the organization to value nuclear safety and equipment longevity over short-time production.
		Continuous monitoring and alarms for Sodium, Chlorides and Sulfates (*Detection*)	3	Did Not Fail	The detection methods used were found to be effective based on the response to this event. Depending on the significance of the event, it is possible to mitigate a condenser in-leakage with by rapidly performing a unit down power and by draining the affected waterbox. However, during the 2/15/15 event the in-leakage was too large to mitigate. All indications were immediately offscale high and Action Level 3 was confirmed exceed by an order of magnitude over the criteria and at the first sampling opportunity.
		Steam Generator Blowdown (*Correction*)	1	Did Not Provide	The blowdown system could be used to mitigate a very small leak but is not intended as a system for protection of the steam generators from seawater in-leakage.
		Condensate Polisher (*Correction*)	1	Did Not Provide	The blowdown system could be used to mitigate a very small leak but is not intended as a system for protection of the steam generators from seawater in-leakage.

Attachment #5: Hazard-Barrier-Target Analysis

Target	Hazard	Barrier	SPS	Conclusion	Comments
Condenser Tube Integrity	Sea Water In-Leakage	Material Selection (*Prevention*)	1	**Failed Barrier** **RC-1**	The St. Lucie Unit 1 Condenser was re-tubed with titanium tubes in the early 1980's (D31). Unit 2 Condenser tubes were installed pre-startup in 1983 (D56). The St Lucie Condenser tubes are Titanium, ASTM B388 Grade 2 (D56). This material has excellent corrosion resistance to seawater and is standard for tubes in steam surface condensers. These tubes are susceptible to various failures in a condenser. The most common failures are due to impingement of steam or water droplets, hydriding, and vibration (cyclic) fatigue (D42). In Unit 2 SL2-22 refueling outage (Fall 2015), 2A1 lower bundle tubes R74-T53 and R76-T50 were removed from the 2A1 condenser bundle. The R74-T53 tubing segment exhibited a longitudinal crack approximately 180° from the seam weld that was OD-initiated, brittle, and appeared to be a progressive cracking mechanism. The forensics concluded that installation damage was key cause for failure. FPL Nuclear Fleet Programs concluded that the cause of the failed tube was tube damage during installation. Each PSL condenser has 14 main tube support plates creating 15 tube bays in each bundle, with intermediate support plates (D56). Current standards recommend a maximum span of 30.05" for titanium tubes in a steam surface condenser (HEI Standard) for vibration (D57). The St Lucie condensers have tube supports located 38.25" apart. This was reviewed for Extended Power Uprate and the tubes have been provided with intermediate supports or stakes in regions of higher steam velocities to mitigate vibration (D22). In 2006, a Unit 2 Condenser tube in the 2B2 waterbox also experienced a failure attributed to a longitudinal thru-wall crack (D24, D53, D54).

Attachment #5: Hazard-Barrier-Target Analysis

Target	Hazard	Barrier	SPS	Conclusion	Comments
		Condenser Tube Cleaning System (*Prevention*)	1	Did Not Provide	The condenser tube cleaning system (CTCS) circulates sponge balls through the tubes to prevent biological fouling.
		Eddy Current Testing (*Detection*)	2	**Did Not Provide** **CC-2**	Eddy Current testing (ECT) is the industry standard means of predicting the future failure of a tube (D18, D20). St Lucie performs some ECT in every water box every refueling outage. The ECT is done on 10% of tubes in each box. The current practice is to perform 100% ECT on one water box every outage so that all tubes are tested at least once every four refueling outages (4R) on a rotating basis (D23, D28). The last 100% ECT performed on 2A1 waterbox was in 2012 outage SL2-20. Tube R74-T53 was tested in 2012, and again in the 10% population tested in 2014 outage SL2-21. Both of these tests identified a “non-quantifiable signal” (NQS) at the outlet end of the tube. The FIP team investigation and metallurgy indicated a longitudinal crack in the region of this NQS. (D10,D11) According to industry standard, a non-quantifiable signal is not a tube defect. This signal type is generally defined as a non-damage signal. Per standards germane to the balance of plant NDE program (D31, D51, D52), a tube that has a NQS does not meet the logic for plugging criteria and therefore, only warrants follow-up with an analyst if it occurs in a suspicious location or a pattern emerges. The ECT testing program is concluded to not be a causal factor in this investigation. Although the tube failure was verified to be at the location of the known NQS, the standards and administrative controls associated with the balance of plant NDE program were adequately executed.
		Hydrostatic Test (*Detection*)	2	Did Not Provide	A hydrostatic test (hydro) is performed at the conclusion of each refueling outage. (D21) The hydro is effective at finding an existing leak but does not provide a means to predict a future leak.

Safety Precedence Sequence (SPS)

1 – Design for minimum hazard
2 – Safety Devices
3 – Safety warnings
4 – Procedures
5 – Training, awareness
6 – Notify Management of risk and accept without corrective action

Conclusions

F - Failed Barrier
DNF - Did Not Fail
DNP - Did Not Provide
DNU – Did Not Use

Attachment #6: NUCLEAR SAFETY CULTURE EVALUATION FORM
(Page 1 of 6)

INTRODUCTION

The safety culture evaluation is performed for each root cause evaluation. The safety culture evaluation is also performed for apparent cause evaluation when addressing a NRC finding. When addressing an NRC finding or violation, the cause evaluation should determine the cause of the condition leading to the finding/violation, and Cross-Cutting aspect if applicable.

The purpose of a safety culture evaluation is to determine if the organization has a healthy bias towards nuclear plant safety, and demonstrates their commitment to nuclear safety culture as an overriding priority across the Reactor Oversight Program cornerstones of safety. The intent of the evaluation is to ensure the analysis assesses the root cause(s) to the Nuclear Safety Cross-Cutting Aspects and the corresponding corrective actions are aligned to mitigate repetitive events.

This Safety Culture Evaluation is part of the Regulatory Margin Corrective Action Strategy defined in LI-AA-200. The focus of this program is to initiate action prior to an NRC performance threshold being crossed.

Each identified cause is categorized against the most relevant aspects in the categories of Human Performance (H), Problem Identification & Resolution (P) and Safety Conscious Work Environment (S).

Note

Per NRC Inspection Manual Chapter 0310, the supplemental cross-cutting aspects (X) are to be considered only when performing or reviewing safety culture assessments during the conduct of the supplemental inspections (95001, 95002 and 95003).

The following definitions are provided as an aide to understanding and performing the safety culture evaluation.

Safety Culture: The core values and behaviors resulting from a collective commitment by leaders and individuals to emphasize safety over competing goals to ensure protection of people and the environment.

Cross-Cutting Area: Fundamental performance characteristics that extend across all of the Reactor Oversight Program cornerstones of safety. These areas are human performance (HU), problem identification and resolution (PI&R), and safety conscious work environment (SCWE).

Cross-Cutting Aspect: A performance characteristic that is the most significant contributor to a performance deficiency.

Attachment #6: NUCLEAR SAFETY CULTURE EVALUATION FORM
(Page 2 of 6)

PROCESS

The Safety culture evaluation should be performed after the analysis has been done, and the root cause(s) have been determined.

1. Evaluate the cause(s) with respect to the NRC Cross-Cutting Areas to determine if the cause(s) align with one or more of the safety culture cross cutting aspects (i.e., is there a relationship between the cause and the aspect). Since the purpose of this Safety Culture evaluation is to assess the current organizational culture, "legacy" causes are excluded. If a cause is determined to be a legacy issue (over 5 years old), the evaluation needs to determine if the cause could still exist in the current organization/program. If the cause could not exist in the current organization/program, it is excluded from the safety culture evaluation. The basis for this exclusion shall be documented. If the cause could still exist in the current organization/programs, a safety culture evaluation should be performed regardless of the "age" of the cause.

2. Using the table below (Nuclear Safety Culture Evaluation Table), document the results of this evaluation.

3. Validate that corrective actions associated with the root cause(s) adequately address any identified relationships. If the existing actions do not adequately address the identified relationship, revise the actions or initiate new actions.

4. Provide a summary of the completed nuclear safety culture evaluation in the root cause report (refer to PI-AA-100-1005 F01). Clearly document the results of the evaluation, include discussion on how the team came to the conclusions of the evaluation, and list any additional actions that were developed or modified as a result of the evaluation.

During the evaluation, consider the following:

From the NRC’s perspective, these components and their defining aspects make up the “management system" model for commercial nuclear power operation.

- If the root cause(s) identified by the analysis does not line up with any of the checklist aspects, this may be indicative of flaws in the analysis approach or conclusions and warrants further review.

- If there are aspects that appear to be strongly related to facts discussed in the analysis, but they are not aligned with any of the identified root cause(s) this may be indicative of flaws in the analysis approach or conclusions and warrants further review.

Attachment #6: NUCLEAR SAFETY CULTURE EVALUATION FORM
(Page 3 of 6)

- If the cause evaluation involves an NRC finding/violation, the following additional step is to be performed:
    - After completing the Safety Culture Evaluation, compare the identified aspects with the aspects identified by the NRC.
    - If they are similar, add a note to the safety culture evaluation to document this fact.
    - If they differ, provide a basis in the safety culture evaluation for the difference.

Attachment #6: NUCLEAR SAFETY CULTURE EVALUATION FORM
(Page 4 of 6)

Nuclear Safety Culture Evaluation Table

06.01 Human Performance (H)

#	Criteria	Comment
H.1	**Resources:** Leaders ensure that personnel, equipment, procedures, and other resources are available and adequate to support nuclear safety (LA.1).	**NC**
H.2	**Field Presence:** Leaders are commonly seen in the work areas of the plant observing, coaching, and reinforcing standards and expectations. Deviations from standards and expectations are corrected promptly. Senior managers ensure supervisory and management oversight of work activities, including contractors and supplemental personnel (LA.2).	**NC**
H.3	**Change Management:** Leaders use a systematic process for evaluating and implementing change so that nuclear safety remains the overriding priority (LA.5).	**NC**
H.4	**Teamwork:** Individuals and work groups communicate and coordinate their activities within and across organizational boundaries to ensure nuclear safety is maintained (PA.3).	**NC**
H.5	**Work Management:** The organization implements a process of planning, controlling, and executing work activities such that nuclear safety is the overriding priority. The work process includes the identification and management of risk commensurate to the work and the need for coordination with different groups or job activities (WP.1).	**NC**
H.6	**Design Margins:** The organization operates and maintains equipment within design margins. Margins are carefully guarded and changed only through a systematic and rigorous process. Special attention is placed on maintaining fission product barriers, defense-in-depth, and safety related equipment (WP.2).	**CC-1**
H.7	**Documentation:** The organization creates and maintains complete, accurate and, up-to-date documentation (WP.3).	**NC**
H.8	**Procedure Adherence:** Individuals follow processes, procedures, and work instructions (WP.4).	**NC**
H.9	**Training:** The organization provides training and ensures knowledge transfer to maintain a knowledgeable, technically competent workforce and instill nuclear safety values (CL.4).	**NC**
H.10	**Bases for Decisions:** Leaders ensure that the bases for operational and organizational decisions are communicated in a timely manner (CO.2).	**NC**
H.11	**Challenge the Unknown:** Individuals stop when faced with uncertain conditions. Risks are evaluated and managed before proceeding (QA.2).	**NC**
H.12	**Avoid Complacency:** Individuals recognize and plan for the possibility of mistakes, latent issues, and inherent risk, even while expecting successful outcomes. Individuals implement appropriate error reduction tools (QA.4).	**RC-1 (Pre-1983)** **CC-2 (2014, 2012)**
H.13	**Consistent Process:** Individuals use a consistent, systematic approach to make decisions. Risk insights are incorporated as appropriate (DM.1).	**NC**
H.14	**Conservative Bias:** Individuals use decision making-practices that emphasize prudent choices over those that are simply allowable. A proposed action is determined to be safe in order to proceed, rather than unsafe in order to stop (DM.2).	**NC**

Attachment #6: NUCLEAR SAFETY CULTURE EVALUATION FORM
(Page 5 of 6)

06.02 Problem Identification and Resolution (P)

#	Criteria	Comment
P.1	**Identification:** The organization implements a corrective action program with a low threshold for identifying issues. Individuals identify issues completely, accurately, and in a timely manner in accordance with the program (PI.1).	**NC**
P.2	**Evaluation:** The organization thoroughly evaluates issues to ensure that resolutions address causes and extent of conditions commensurate with their safety significance (PI.2).	**NC**
P.3	**Resolution:** The organization takes effective corrective actions to address issues in a timely manner commensurate with their safety significance (PI.3).	**NC**
P.4	**Trending:** The organization periodically analyzes information from the corrective action program and other assessments in the aggregate to identify programmatic and common cause issues (PI.4).	**NC**
P.5	**Operating Experience:** The organization systematically and effectively collects, evaluates, and implements relevant internal and external operating experience in a timely manner (CL.1).	**NC**
P.6	**Self-Assessment:** The organization routinely conducts self-critical and objective assessments of its programs and practices (CL.2).	**NC**

06.03 Safety Conscious Work Environment (S)

#	Criteria	Comment
S.1	**SCWE Policy:** The organization effectively implements a policy that supports individuals' rights and responsibilities to raise safety concerns, and does not tolerate harassment, intimidation, retaliation, or discrimination for doing so (RC.1).	**NC**
S.2	**Alternate Process for Raising Concerns**: The organization effectively implements a process for raising and resolving concerns that is independent of line management influence. Safety issues may be raised in confidence and are resolved in a timely and effective manner (RC.2).	**NC**
S.3	**Free Flow of Information:** Individuals communicate openly and candidly, both up, down, and across the organization and with oversight, audit, and regulatory organizations (CO.3).	**NC**

Attachment #6: NUCLEAR SAFETY CULTURE EVALUATION FORM
(Page 6 of 6)

06.04 Supplemental Cross-Cutting Aspects (X)

#	Criteria	Comment
X.1	**Incentives, Sanctions, and Rewards:** Leaders ensure incentives, sanctions, and rewards are aligned with nuclear safety policies and reinforce behaviors and outcomes that reflect safety as the overriding priority (LA.3).	**NC**
X.2	**Strategic Commitment to Safety:** Leaders ensure plant priorities are aligned to reflect nuclear safety as the overriding priority (LA.4).	**NC**
X.3	**Roles, Responsibilities, and Authorities**: Leaders clearly define roles, responsibilities, and authorities to ensure nuclear safety (LA.6).	**NC**
X.4	**Constant Examination:** Leaders ensure that nuclear safety is constantly scrutinized through a variety of monitoring techniques, including assessments of nuclear safety culture (LA.7).	**NC**
X.5	**Leader Behaviors:** Leaders exhibit behaviors that set the standard for safety (LA.8).	**NC**
X.6	**Standards:** Individuals understand the importance of adherence to nuclear standards. All levels of the organization exercise accountability for shortfalls in meeting standards (PA.1).	**NC**
X.7	**Job Ownership:** Individuals understand and demonstrate personal responsibility for the behaviors and work practices that support nuclear safety (PA.2).	**NC**
X.8	**Benchmarking:** The organization learns from other organizations to continuously improve knowledge, skills, and safety performance (CL.3).	**NC**
X.9	**Work Process Communications:** Individuals incorporate safety communications in work activities (CO.1).	**NC**
X.10	**Expectations:** Leaders frequently communicate and reinforce the expectation that nuclear safety is the organization's overriding priority (CO.4).	**NC**
X.11	**Challenge Assumptions:** Individuals challenge assumptions and offer opposing views when they think something is not correct (QA.3).	**NC**
X.12	**Accountability for Decisions:** Single-point accountability is maintained for nuclear safety decisions (DM.3).	**NC**

Attachment #7: Photographs and Illustrations

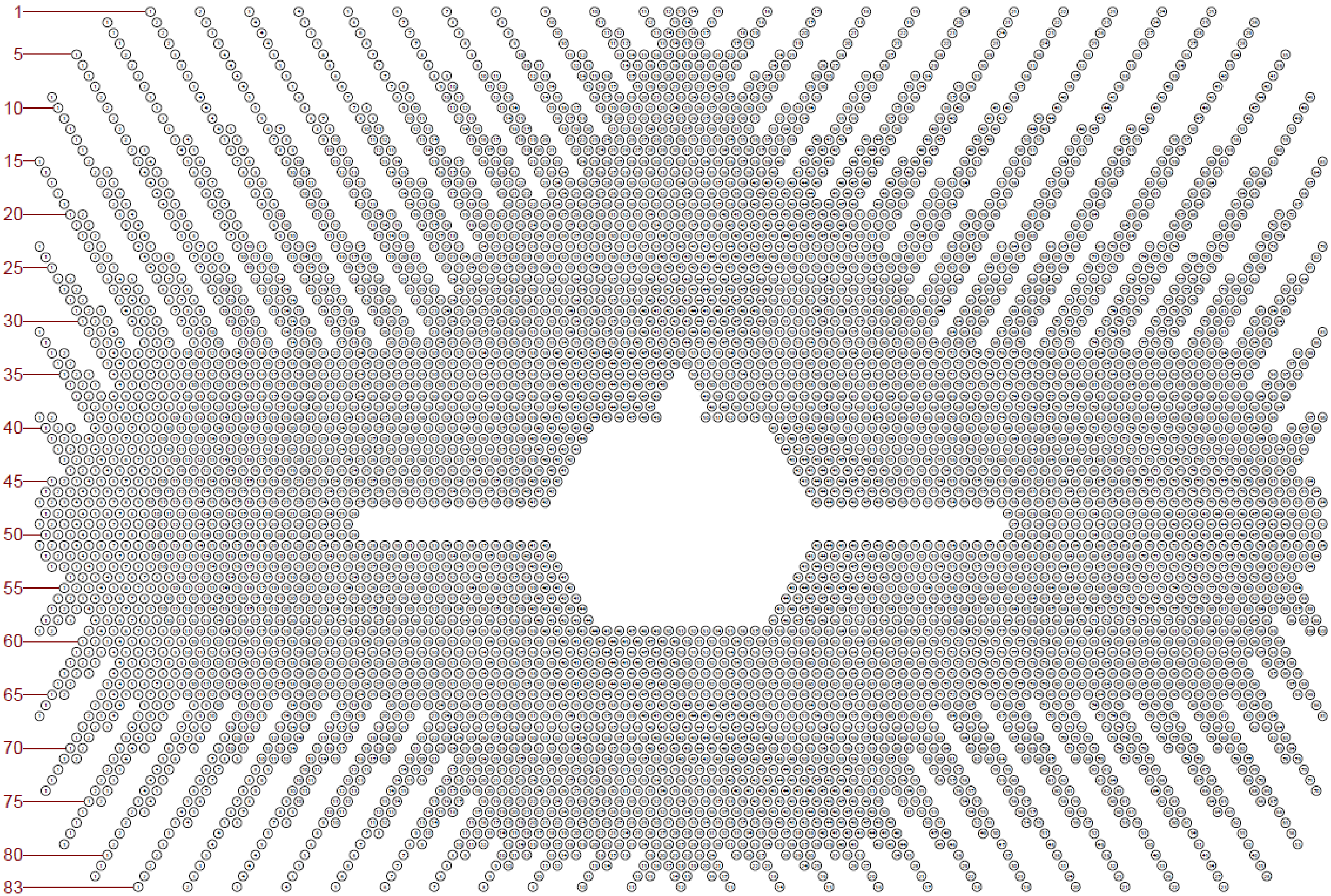


Figure 1: Model lower bundle for Unit 2 Condenser (D11).

Attachment #7: Photographs and Illustrations

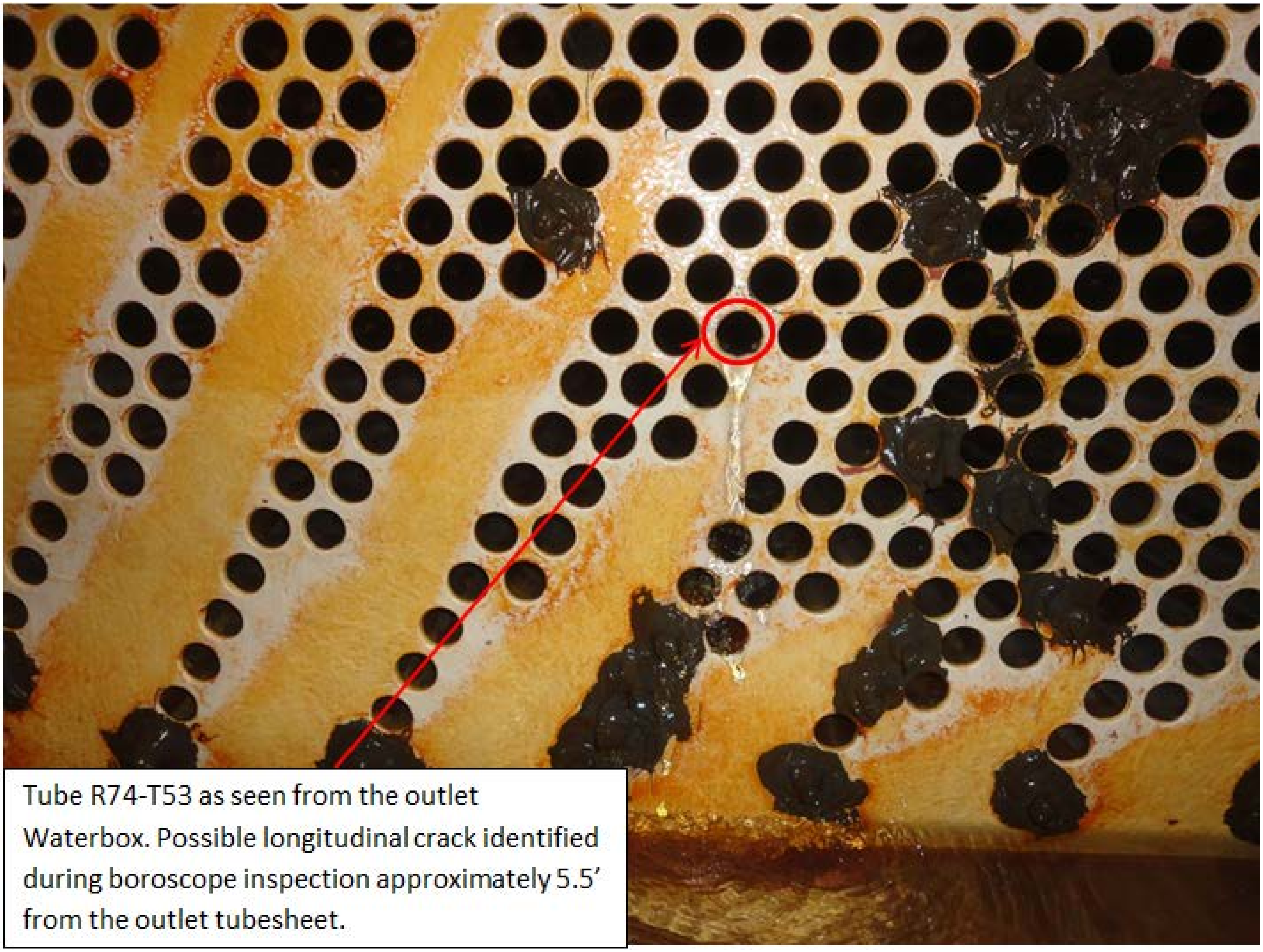


Figure 2: 2A1 lower bundle tube R74-T53 leaking during short notice outage hydrostatic test in February 2015 (Interim Root Cause Report).

Attachment #7: Photographs and Illustrations

Figure 3: Boroscope photo of linear indication on 2A1 R74-T53 as taken during short notice outage in February 2015 (Interim Root Cause Report).

Attachment #7: Photographs and Illustrations

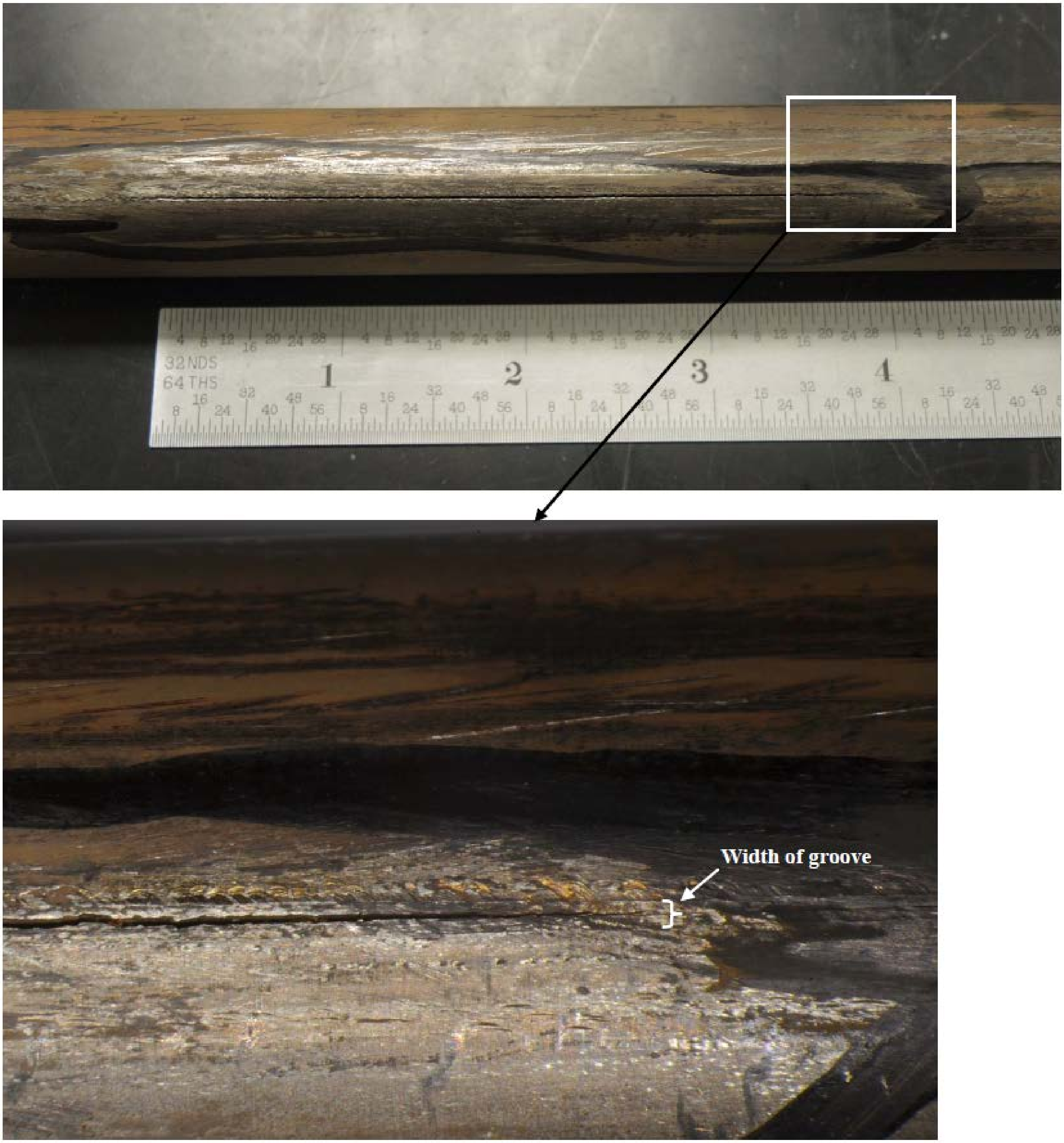


Figure 4: Metallurgy analysis of 2015 failed 2A1 lower bundle tube R74-T53 (D45).

Attachment #7: Photographs and Illustrations

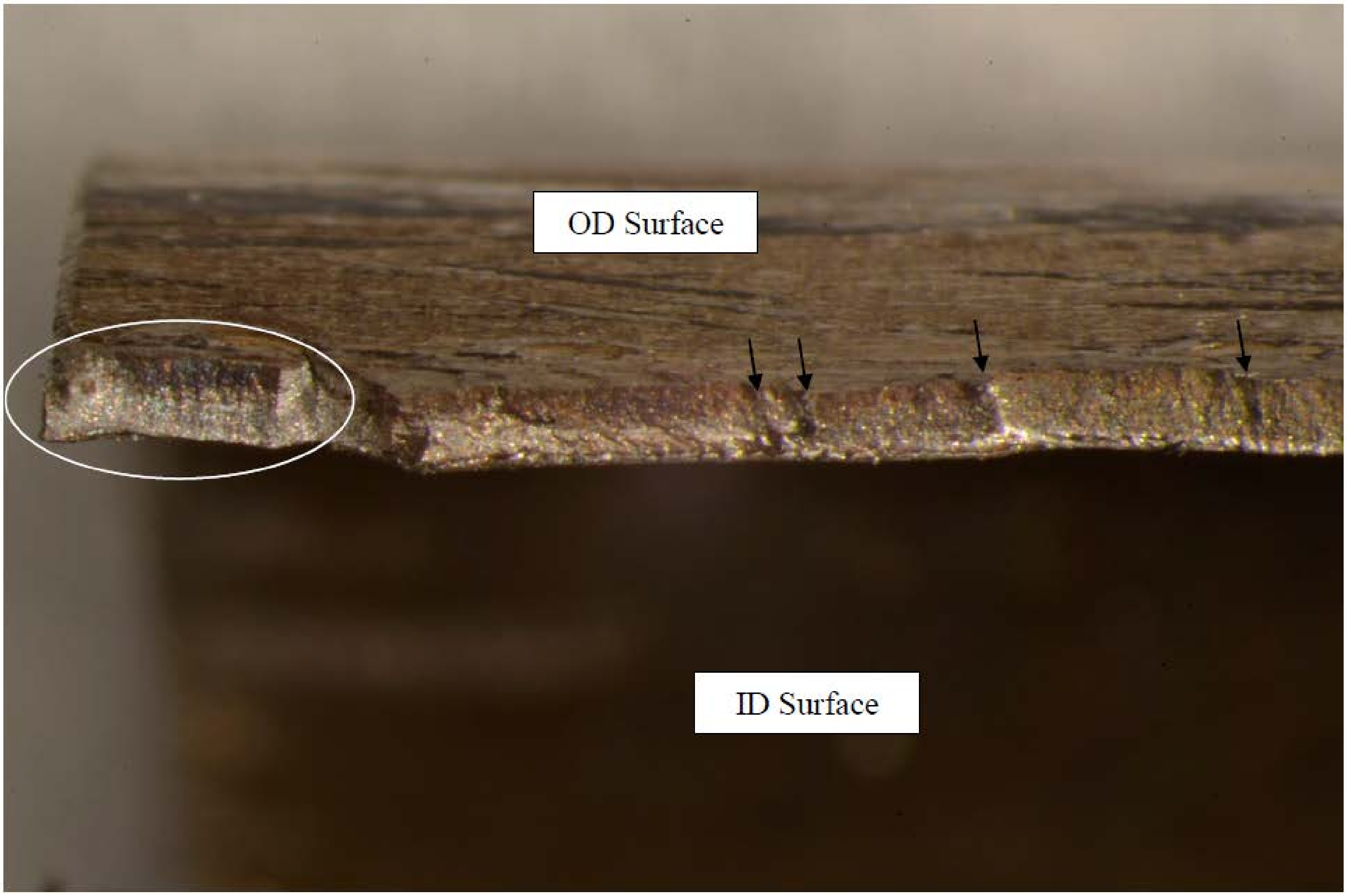


Figure 5: Metallurgy analysis of 2015 failed 2A1 lower bundle tube R74-T53 (D45).

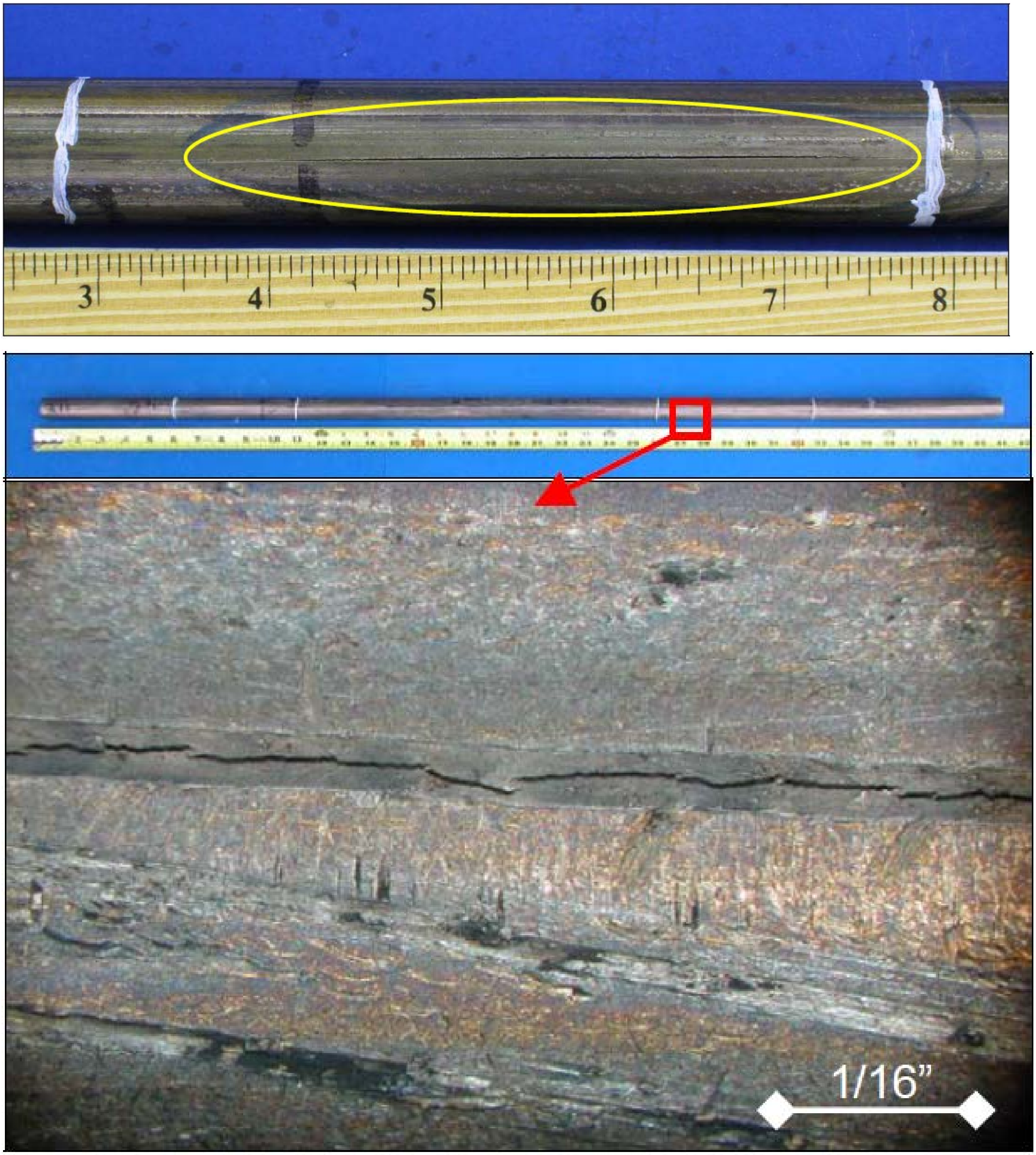


Figure 6: Metallurgy analysis of 2006 failed 2B2 lower bundle tube R76-T24 (D13).

Attachment #7: Photographs and Illustrations

Figure 7: Illustration of the steam space of the Unit 2 Condenser, tube bundles, and tube baffle plates.

Attachment #7: Photographs and Illustrations

Project=2A1-MC-LOWER_SL2-21 Site=PSL2 Comp=2A1-MC-LOWER Date=03/12/2014 16:18:09

Non-quantifiable Signal (NQS)
No change from history

File=126 ROW=74 TUB=53 Loc=26+19.51

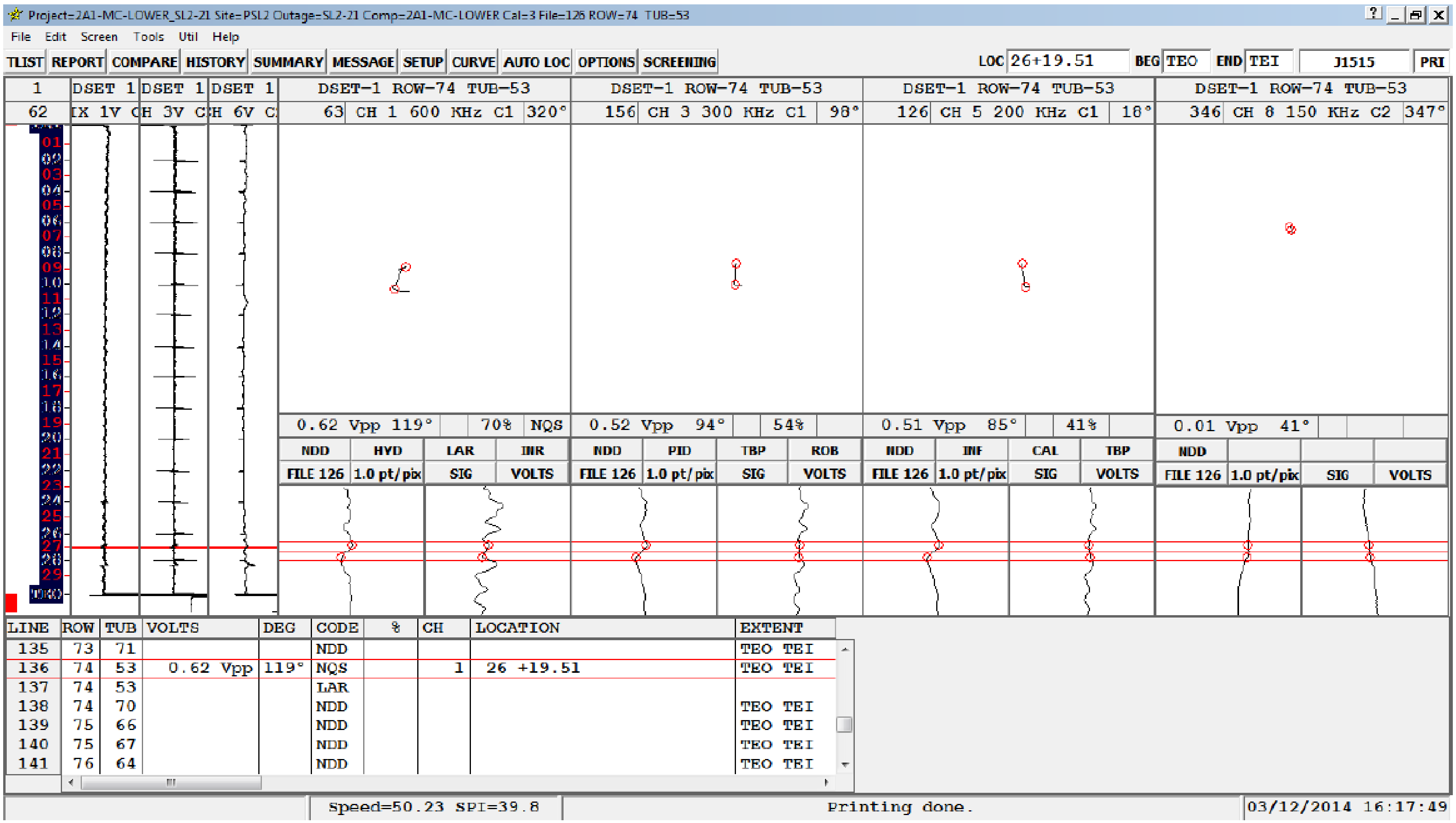


Figure 8: SL2-21 (Spring 2014) ECT NQS signal of failed 2A1 lower bundle tube R74-T53 (D10).

Attachment #8: Total Number of Tubes Plugged

UNIT 1 TOTAL NUMBER OF CONDENSER TUBES PLUGGED

	1A1	1A2	1B1	1B2
Upper	199	245	243	131
Lower	379	333	382	227
# Total Plugged	578	578	625	358
# Tubes Total in Each Bundle	5980	5980	5980	5980
Plugging percentage	4.8%	4.8%	5.2%	3.0%

Total Plugged	2139
Total Tubes	47840
Percentage Plugged	4.5%

Updated 3/3/2016

Attachment #8: Total Number of Tubes Plugged

UNIT 2 TOTAL NUMBER OF CONDENSER TUBES PLUGGED

	2A1	2A2	2B1	2B2
Upper	122	87	113	107
Lower	145	87	92	132
# Total Plugged	267	174	205	239
# Tubes Total in Each Bundle	5980	5980	5980	5980
Plugging percentage	2.2%	1.5%	1.7%	2.0%

Total Plugged	885
Total Tubes	47840
Percentage Plugged	1.8%

Updated 3/3/2016

Florida Power & Light Company
Docket No. 160001-EI
Staff's First Data Request
Question No. 3

Q.

In his 2015 September testimony regarding the February 2015 outage at St. Lucie Unit 2, at pages 6-8, witness Grissette stated that the outage was due to seawater intrusion into a condenser tube. He further stated that FPL would perform detailed testing and remove the suspect tubing during its October 2015 refueling outage, and perform lab testing to determine the root cause and perform any necessary corrective actions to prevent recurrence.

Were any corrective actions found to be necessary? If so, please provide a detailed description of those actions, and how they will prevent recurrence.

A.

Yes. The root cause evaluation provided in response to Staff's First Data Request No. 2 includes an executive summary that identifies the root cause along with corrective actions (CAs) and corrective actions to prevent recurrence (CAPRs) in the chart beginning on page 4 of the document. The CAPRs are designed to apply the lessons learned from the eddy current data recorded during previous maintenance outages for the subject tube and prior to its failure. Condenser tubes that exhibit similar eddy current signals will be preventatively plugged.

Condenser installation and retubing processes have improved since the time of original Unit 2 construction to eliminate the process of singular tube installation. The current modular process (if needed) would replace the condenser tubes in sections rather than feeding single tubes through tight structures.

Q.

In his 2015 September testimony regarding the April 2015 outage at St. Lucie Unit 2, at pages 8-9, witness Grissette stated that the outage was due to a leak in discharge header piping due to vibration fatigue at the weld of a support lug due to a legacy design issue. He further stated that FPL replaced the affected piping and modified the support for the pipe and revised the engineering standard to reflect the modifications.

Did FPL undertake any further actions to address the legacy design issue that was the foundation of the outage? If so, please provide a detailed description of those actions and any results which came from them.

A.

No. The corrective actions described in FPL witness Grissette's testimony provided an effective solution.

Q.

In his 2015 September testimony regarding the April 2015 outage at St. Lucie Unit 2, at pages 8-9, witness Grissette stated that the outage was due to a leak in discharge header piping due to vibration fatigue at the weld of a support lug due to a legacy design issue. He further stated that FPL replaced the affected piping and modified the support for the pipe and revised the engineering standard to reflect the modifications.

Is this same legacy design issue present in FPL's other nuclear units? If so, please provide a detailed explanation of any plans FPL has to address this issue at its other nuclear units.

A.

The potential exists for similar legacy design issues to be latent and undetectable at any power plant. Accordingly, applicable industrial Codes require a variety of rigorous weld inspections that are designed to detect weld flaws and defects to limit their ability to affect safety-related pressure boundaries. As material and weld performance operating experience (OE) is collected, the nuclear industry programmatically shares this OE so that standards can be improved to prevent, or at least minimize, the potential for future events. The lessons learned from this event were shared with FPL's other nuclear plant and the rest of the US nuclear plants. Further, comprehensive walk-downs were performed at both St. Lucie and Turkey Point to verify the integrity of all similar welded support brackets in containment.