Request for MRC Approval of CR Investigation, CAPR, or Collective EFR Assignment Due Date Extension

Requestor: Roddey, T Department: Engineering

CR & Assignment Number: 907846

CR Title: Root Cause Evaluation for Tritium Leak

Present Due Date: 5/26/09

Desired Due Date: 6/5/09

Reason for Extension Request: Request 10 day extension due to 1F20 support work requiring additional resources.

Risk Associated with Extension (discuss interim corrective actions): Little risk due to tritium issues are being tracked on the emergent issues list and through the OCC when required.

Impact Associated with Extension: None

Department Approval/Date:__R. Skelskey______________

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Root Cause Evaluation Report

Tritium Identified in Emergency Service Water (ESW) Vault

Title: Tritium Identified in Emergency Service Water (ESW) Vault
Unit(s): Oyster Creek, Unit 1

Event Date: April 15, 2009
Event Time: 15:38

Action Tracking Item Number: 00907846
Report Date: June 5, 2009

Sponsoring Manager: Russell Peak, Site Engineering Director

Investigators:
David Olszewski, Oyster Creek Engineering Response Team Manager
Thomas Roddey, Oyster Creek Engineering Programs Manager
Megan Caldeira, Oyster Creek Programs Engineer
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Pete Tamburro, Corporate License Renewal
Greg Lupia, Corporate Engineering
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Executive Summary:

On April 15, 2009, in preparation for work inside the Emergency Service Water (ESW) vault, water was found inside the vault. As part of standard practices for water removal, the water was pumped into drums and sampled for gamma emitters, tritium, and pH. Sample analysis identified tritium levels at 102,000 pCi/l. Based on a verbal agreement, the station provides a report to the New Jersey Department of Environmental Protection when groundwater tritium levels are greater than or equal to 2,000 picocuries per liter (pCi/l), which is the state's lower limit for detectable tritium activity. The total activity was below the Environmental Protection Agency's reportable limit of 100 Ci for tritium as specified in 40 CFR Part 302, "Designation, Reportable Quantities, and Notification."

Investigation for the issue determined that the release of tritiated water was caused by leaks in the 8-inch and 10-inch carbon steel Condensate System lines, SS-4 and CS-24 respectively. This investigation aimed to determine separate root causes for the material condition failure of the pipes and for the programmatic aspects related to these failures. The root cause investigation determined that the piping leaks developed due to a corrosion mechanism known as anodic dissolution. Poor application of pipe coating left the buried pipes susceptible to this corrosion. The station's Buried Pipe Program was reviewed as part of the evaluation of programmatic and organizational aspects related to the pipe failure. The investigation determined that the program basis document was flawed due to inadequate configuration management and design controls, which resulted in invalid assumptions being used in the

development of the program. Inadequate configuration management and design controls resulted in invalid assumptions that were used as the basis for development of the program, the associated assessment of risks and consequences, and, consequently, the station's strategic approach to tritium leak mitigation. The station missed opportunities to properly characterize risks and consequences associated with the degraded Condensate System piping. These risks and consequences were developed as part of the program basis document. The program basis document is flawed in that the 8-inch Condensate line was incorrectly identified as stainless steel as opposed to CS piping, which is the currently installed material.

Scope of the Investigation

The purpose of this investigation is to determine the Root Cause and contributors to pipe failures at Oyster Creek Generating Station that resulted in the leakage of tritiated condensate transfer system water into the station's groundwater. The investigation will review sources of tritium onsite, the site's procedures for mitigating the risk of tritium releases to the environment, station efforts to mitigate this risk, and organizational and programmatic effectiveness associated with tritium risk and impact mitigation. Additionally, the investigation will determine the appropriate corrective actions for the causes identified.

Summary of Events

A team was formed to identify potential sources of tritiated water leaks and actions were taken to sample onsite groundwater wells and the plant discharge. A sample of well MW-K15-1A, located southwest of the Condensate Storage Tank (CST), measured 4.5×10^6 pCi/l. This result was determined to be similar to tritium levels seen in the CST. Based on this information, the leakage source was narrowed to the Condensate System. Using Oyster Creek Topical Report 116, "Oyster Creek Underground Piping Program Description and Status," a list of high probability locations for the leakage were selected.

Root Cause and Corrective Actions to Prevent Recurrence (CAPRs)

The Root Cause of the degraded 8-inch and 10-inch Condensate System piping is "anodic dissolution" resulting from disbondment of the coating and susceptible material **(Root Cause 1)**. The Corrective Action to Prevent Recurrence (CAPR) is to implement a strategic plan that includes moving direct buried Condensate System piping either above ground or in monitored trenches.

The station missed opportunities to properly characterize risks and consequences associated with the degraded Condensate System piping. These risks and consequences were developed as part of the program basis document. The Root Cause of these deficiencies is that the program basis document is flawed due to inadequate configuration management and design controls that resulted in invalid assumptions being used as the basis for development of the program, the associated assessment of risks and consequences, and, thereby, the station's strategic approach to tritium leak mitigation **(Root Cause 2)**. The CAPR for this Root Cause is to revise the program basis document (i.e., TR-116) to correct plant design details, risks, consequences, recommend inspection frequencies, and inspection methods following a thorough program assessment.

Contributing Causes

Improperly applied coatings and lack of coatings in some areas of the pipe contributed to coating disbondment and the resultant localized corrosion **(Contributing Cause #1)**. A review of work order closure identified that repairs were limited to the relatively small areas identified as requiring either coating or pipe repairs. In September 1991, an Engineering evaluation was performed and documented in P.E. 125-1 File No. 1001-91, "Coating Repair on 1-inch, 8-inch and 10-inch CS Underground Condensate Lines." This evaluation supported the visual inspection of the pipe coating, with actions to remove coatings, inspect, repair, and recoat in select areas. It is noteworthy that the associated maintenance activities did not remove all coatings for a visual and/or UT inspections on the entirety of the exposed pipe. Such inspections would have allowed a more rigorous examination, particularly given that several pipes were identified as having some degree of degradation and since the 10-inch CS line had multiple holes, indicating the potential for extensive corrosion of the pipe. Consistent with the point-by-point examination, the repairs of the piping and coating were performed in a "patchwork" manner.

In addition, "spark testing" was performed on additional areas of coated piping on the 8-inch and 10-inch lines. The associated work order did not identify a required voltage for this testing, and did not document consideration of environmental factors as recommended in industry guidance document ASTM D5162 - 08, "Standard Practice for Discontinuity (Holiday) Testing of Nonconductive Protective Coating on Metallic Substrates." Without such considerations, spark testing can cause coating damage. The coating inconsistencies and defects were the result of inadequate guidance in work instructions. Additionally, failure to properly and accurately document some completed maintenance and repair activities resulted in quality records not being established and retained for the completed work. Some work order closing remarks did not include adequate descriptions for completed work. Examples exist where references made in work orders could not be followed to a retrievable document. Some underground piping program drawings were not updated and properly maintained as part of modifications. The incomplete/inaccurate documentation led to invalid assumptions around pipe configuration, configuration changes, soil and material condition, and abandoned pipe in the program basis document.

The change management processes prior to implementing the Exelon Buried Pipe Program did not support effectively managing design changes and related projects during site ownership and management changes **(Contributing Cause #2)**. The station had several changes of ownership and management between 1991 and 2009. Also, several modifications aimed at mitigating the station's risk to underground tritium leaks were planned, including design changes to move lines above ground, move piping into concrete trenches, and replace lines using more corrosion-resistant materials. In most instances, these planned modifications were in response to identified leaks. However, most were not implemented. In addition, management decisions were made in the mid-1990s to allow the station's operating license to expire. Modifications not implemented, as well as cancelled maintenance and repair activities, should have been re-evaluated as vulnerabilities for long-term piping integrity.

The combined information from non-intrusive and direct inspections is used to identify the need for long-term repairs and replacements. The inspections rely on available technologies, each of which has specific limitations. This includes Visual Inspection, Ultrasonic Testing (UT), and Guided Wave inspections. Any of these methods alone would not allow for 100% assurance of pipe integrity. Instead, they are used in combination to find localized areas of concern. Since 100% verification of pipe integrity is not practical, even these extensive measures leave the site vulnerable to localized corrosion because the methodologies used by the buried pipe program do not, in all instances, locate defects, and cannot assess entire continuous full lengths of pipe **(Contributing Cause #3)**.

The industry considers Guided Wave™ technology to be an acceptable means to perform quick non-intrusive inspections of long sections of pipe to identify degradation. However, industry experience has shown that at the current level of development, even the most sophisticated indirect inspection methods are not as accurate at sizing the axial and circumferential extents of a corroded area as UT and, as a result, a follow-up direct examination such as UT would be required to characterized the area of corrosion. As a result, the current risk to the organization is that other buried piping may have similar localized corrosion that is not being effectively detected and managed.

This event was reviewed for Safety Culture Components in accordance with step 4.2.4 of procedure LS-AA-125-1001 by Regulatory Assurance and no additional investigations are required.

Significance of Event:
The tritium level in the water that was leaking from the 8-inch and 10-inch Condensate lines was above the reporting limits for the State of New Jersey (2,000 pCi/L) based on a voluntary verbal agreement with the New Jersey Department of Environmental Protection. The Environmental Protection Agency's reportable quantity is 100 Ci per 40 CFR Part 302. There is a small radiological risk associated with the underground pipe leaks. The leaking water spread radioactive contamination to the environment. The water contained tritium that produces a low energy beta dose. The urgency to identify the source of the leak led to excavation of several piping lines during a forced outage that lasted roughly 8 days. Significant financial and personnel resources were required to restore the integrity of the piping. In the event the soil needs to be remediated, a significant cost will be incurred by the company.

Event Description:

Root Cause Evaluation Report

Tritium Identified in Emergency Service Water (ESW) Vault

The following event description written in a sequential narrative format is also detailed in the Event and Causal Factor Chart in Attachment C.

1980s: Four-inch and six-inch buried aluminum lines around the CST and the Demineralized Tanks were confirmed leaking.

Early 1990s: The station initiates the Oyster Creek Underground Piping Program after several buried piping leaks were discovered, including the aluminum Condensate Transfer lines. The leaking pipes were repaired or replaced.

1991: A system based buried pipe inventory was developed. Priorities given to each system were based on the following: Nuclear Safety; Environmental Impact; Plant Availability, and System Reliability. Priority 1 includes lines that have immediate safety significance either the plant or the environment. Priority 2 includes lines that would require an eventual plant shutdown or have an eventual environmental impact. Priority 3 includes those lines whose leak would have no environmental hazard, immediate plant shut down risk, or safety impact risk. The Condensate Transfer System was designated as Priority 1. Reference Topical Report 116 – Attachment 2.

1991: The CST developed a leak requiring replacement of the tank bottom.

1991: GPU Nuclear Document OC-MM-323643-001, Rev. 0, "Mini-Mod for Replacement of Condenser Letdown Line from the Turbine Building to the Condensate Transfer Pump Building" was initiated, but not implemented. The goals of the modification were as follows.

- Reroute piping from beneath the Condensate Transfer Building to outside
- Flange SS piping to existing CS piping in the Condenser Bay
- Pre-assemble, coat, and wrap below-ground piping
- Spray-coat coated pipe with a Polyken™ type primer followed by non-conductive Polyken™ tape

July 22, 1991: Work Order C0032859 repaired a hole in the 8-inch carbon steel piping with a plug installed into a seal welded coupling. The CREM identified the cause of failure as pipe corrosion.

July 25, 1991: Job Order 032927 completed a weld repair on a hole in the 8-inch Condensate pipe via instructions written in 125-1 Evaluation 0924-91. Job Order 032927 also completed Ultrasonic Testing (UT) at pipe locations marked with duct tape.

October 8, 1991 through January 8, 1992: Work order C0033031 recoats the 8-inch and 10-inch Condensate lines per 125-1 Evaluation 1001-91. The work order and the evaluation are consistent in that no activity was designated to remove all coatings on these lines and inspect the entire pipe for degradation. Only those areas where coatings were removed were inspected, and the coating was reapplied only to the inspected areas and to areas where degraded piping was identified.

- October 9, 1991: Spark testing revealed five small (quarter-sized) defects in the 10-inch line and two areas of defects in the 8-inch line (approximately two square feet)
- November 22, 1991: 8-inch and 10-inch coating failure locations were ready to recoat
- November 25, 1991: The transfer line repairs were canceled with no mention of which lines were cancelled in the CREM
- November 26, 1991: The 8-inch and 10-inch pipes were recoated in the failed areas
- December 2, 1991: The 8-inch and 10-inch carbon steel piping was recoated with Devoe 167 primer and Devoe 235 coating
- December 7, 1991: "Wet sponge" holiday testing of all carbon steel pipeline coating was completed successfully. Three layers of Polyken™ tape were applied to the 8-inch carbon steel pipe section near the furthest west location around the new pier/rebar/concrete pad. Wet sponge holiday testing on Devoe-coated sections of the 8-inch and 10-inch pipe was reviewed by Quality Assurance and passed. The coating on the 6-inch aluminum line exhibited significant degradation and the recommendation was made to replace the coating on the entire length of this 6-inch line.

1996: A modification was completed to bring the majority of Condensate and Condensate Transfer piping above ground. The modification was tracked through OC-CCD-328376-001 and left four condensate lines buried, including SS-4 and CS-24.

1997: A more refined review was performed of the program inventory. The review focused on systems with underground pipe that contained contaminated fluids. The review, in general, did not look at the Priority #1 systems from the 1991 review. It was believed that activities were already underway to address identified problems. This review focused on Priority #2 and some Priority #3 systems. The review assessed the susceptibility of each line for developing a leak and the radiological and environmental consequences of leaks should they occur. A revised matrix was developed in which the susceptibility and consequence of a leak were documented.

1997: TDR-1218, "Evaluation of Oyster Creek Underground Piping Which Contain Contaminated Fluids," was created.

1997: Oyster Creek owner, GPU Nuclear, decides to decommission or the sell the plant.

2000: AmerGen purchases Oyster Creek.

2001: Work orders completed before 2001 were transferred into PIMS.

2004: Exelon announced the decision to pursue relicensing of Oyster Creek to 2029.

2005: The Buried Piping Program was revised to include an assessment of pipe service life and to include considerations for license renewal. Work orders were reviewed for developing the program basis document, including C0033031. Although this work order indicates that the coating repairs were only applied in specific sections of pipe, the program basis document considered the coating to be completely new for the entire length of the Condensate piping as of 1991. Another assumption used in the risk ranking of the program basis document is that the 8-inch line was replaced with stainless steel per OC-MM-323643-001, based on drawing 3D-421-22-1000, Revision 0. This drawing was associated with a modification to replace the 8-inch CS piping with stainless steel. The modification was not implemented.

August 2006: CST-2, the lysimeter on the southwest corner of the CST, was sampled and had a tritium concentration of less than 200 pCi/L.

2007: Exelon implements a fleetwide Buried Piping Program and standard procedure ER-AA-5400. The program was piloted at four Exelon sites, including Oyster Creek. In 2007, a new risk rank evaluation was performed at a more refined level. Underground lines in the program were segmented in approximately 20-foot lengths. Each segment was then risk ranked. A database was developed as part of the evaluation to capture specific information and compute risk rankings for each segment in accordance with ER-AA-5400.

July 2007: Buried Piping Systems Susceptibility Analysis Document, Technical Report 07-0807-TR-002, was prepared by Altran Solutions. Recommendations from the Altran analysis were referenced in Topical Report 116 (program basis document). The Condensate System was divided into two segments. Segments 1 of CS-24 and SS-4 were assigned a risk ranking of 1250; segments 2 of CS-24 and SS-4 were assigned a risk ranking of 1820. The assigned risk ranking translates to a level of risk, ranging from low to high.

October 16, 2007 through October 18, 2007: In accordance with the Buried Piping Program, lines A-4 and CS-24 were inspected by Structural Integrity Associates, Inc. (SIA), using Guided Wave™ Technology per Work Order C2015637. PLR-07-441, Revision 1, describes the results on CS-24 as follows: "This section of pipe appears to be a minor concern. Possible coating failure or thickness change." The Guided Wave™ inspection was attempted on SS-4, but discovered to be impossible due to configuration. IR 00686803 was written to document the inability to complete Guided Wave Inspection on twelve lines, including SS-4. IR 00696852 was written to document the need to inspect the lines during Fall 2008 refueling outage 1R22.

2008: A partial visual inspection was completed on line A-4 per the Buried Piping Program.

January 7, 2008: PIMS AR A2181188 (Guided Wave Inspection of the remaining 24 buried pipes required to implement the Buried Pipe Program including SS-4) was descoped from 1R22 via form #1R22-0195 due to a lack of funding.

2008: In-Service Testing (IST) surveillance 644.4.002, for the Condensate Storage System, was updated to indicate that an underground leak might cause an IST failure.

January 2009: Buried Piping Program Owner makes the recommendation to modify CS-26 and CS-38 to an above ground configuration.

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March 2009: Oyster Creek Engineering performed Technical Evaluation Passport ATI 891862 Assignment 4 to establish an inspection schedule for the CST. The first scheduled inspection is December 2009.

March 10, 2009 through March 12, 2009: The following wells were monitored with tritium levels less than 200 pCi/L: W-3, W-4, W-5, W-6 and MW-15K-1A.

April 15, 2009, at 15:38: Tritium was identified in the ESW vault. In preparation for work inside the vault, water found inside the vault was pumped into drums and sampled for gamma emitters, tritium, and pH. There were no gamma emitters identified, pH was 7.62, and the tritium was 102,000 pCi/l. The reporting threshold to the New Jersey DEP for tritium is 2,000 pCi/l based on a verbal agreement between the station and the NJ DEP.

April 15, 2009: IR 00907846 was initiated to document the tritiated water.

April 16, 2009: A team was formed to identify potential sources of tritiated water leaks. Based on measurements of tritium found in well MW-K15-1A, it was determined that the source of leakage was from the Condensate/Condensate Transfer System to the ground. This was postulated because the well sample tritium activity, 4.5×10^6 pCi/l, was similar to the expected activity of CST water. Using Oyster Creek Topical Report 116, "Oyster Creek Underground Piping Program Description and Status," a list of high probability piping locations was created for pinpointed troubleshooting.

April 18, 2009: Guided Wave™ inspections were performed on buried Condensate lines. Guided Wave™ was intended to help find the leak location. It was also used to determine the extent of condition for the lines in the area potentially contributing to the tritium found in the sampling wells. UT and visual inspections were also used. Guided Wave™ inspections were combined with UT inspections to verify the results. The following lines were inspected. The 6-inch Condensate Transfer discharge (aluminum), 10-inch diameter Hotwell Level Control to Hotwell (carbon steel), and 8-inch diameter Hotwell Level Control to Hotwell (carbon steel) were inspected using Guided Wave™. Guided Wave™ results indicated severe corrosion on the 8-inch line; however, follow-up UT performed on April 28, 2009, found only minor corrosion.

April 20, 2009: Perform a PINV and obtain management approval. After approval, submit the PINV to the NDO Mailbox and the NRC Resident. The PINV included the following plan:
Evaluate all inputs into and from the ESW vault for potential sources of tritium

1. Inspect other vaults in the vicinity and sampling for tritium as warranted
2. Collect water samples from:
    a. Monitoring wells in the general vicinity of the cable vault – W-3, W-4, W-5, W-6 and MW-15K-1A. These wells were sampled during the March 10-12, 2009 period. The results of tritium analyses on those samples were all < 200 pCi/L.
    b. Lysimeter in the vicinity of the cable vault – CST-9. This lysimeter was sampled on March 11, 2009 and the tritium concentration was < 200 pCi/L.

c. Lysimeter on the southwest corner of the Condensate Storage Tank – CST-2. This lysimeter was last sampled in August of 2006 when the tritium concentration was found to be < 200 pCi/L.
d. Surface water sample from the main condenser discharge. This is not a routine sampling point.

The samples were shipped to Teledyne Brown Engineering to be analyzed for tritium, strontium-90 and gamma emitting radionuclides utilizing the detectable limits (LLDs) specified for the Radiological Groundwater Protection Program.

April 26, 2009: Underground Condensate lines SS-4 and CS-24 were identified as the sources of the leak of the tritiated water into the ground water table using the described methods. A leak on the bottom of the 8-inch carbon steel line, SS-4, was identified during excavation. A pipe clamp was installed to stop leakage. Non-destructive examination (NDE) of the area around the hole identified a 7-inch by 7-inch square area of involved corrosion and degraded piping. Based on UT results, the station initially replaced a ten-foot section of the 8-inch pipe, which included the degraded areas. Subsequently, the Condensate System was restored to operation. While transferring water from the Hotwell to the CST, a leak was identified on the 10-inch carbon steel CST to Hotwell makeup line, CS-24, in an area that had not been fully excavated. The pipe was pressurized to no more than 40 psig during the transfer evolution and the leak was isolated shortly after discovery. Guided Wave™ analysis was performed on the removed section of the 8-inch line to determine the efficacy of this technology in assessing pipe integrity. Evaluation of the data did not identify the known flaw in the 8-inch line. Based on an inability to detect the degraded section of the 8-inch line, the station conservatively excavated and replaced approximately 30 feet of the 8-inch and 10-inch Condensate System lines.

The ultrasonic testing results from 1F20 for excavated lines between the Condensate Transfer and Turbine Buildings are documented in the table below.

Pipe Size	System #	1.1. 1.2.	Material	Design Press.	Schedule / Thick	87.5% of Wall	Code Min Wall	Actual (lowest) UT Results	Comments
1"	421	CH-1c	CS – A106 Gr. A or B	75 psi	80 / 0.179"	0.157"	0.004"	0.152"	Judged OK until 1R23
6"	424	CH-5c	Alum – 6061 Gr. T4 or T6	200 psi	40 / 0.280"	0.245"	0.109"	> 87.5%	OK
8"	421	CH-2a	CS – A106 Gr. B	370 psi	40 / 0.322"	0.282"	0.105"	a) Through wall hole near Cond Transfer house b) 0.265" @ ~ 4 ft from TB wall c) 0.117" @ 5" from TB wall	Replaced all but 3" at wall

Pipe Size	System #	1.1. 1.2.	Material	Design Press.	Schedule / Thick	87.5% of Wall	Code Min Wall	Actual (lowest) UT Results	Comments
10"	421	CH-1c	CS – A106 Gr. A or B	75 psi	40 / 0.365"	0.319"	0.034"	a) 0.322" @ 18 ft from TB wall b) Through wall hole below Cond Transfer house c) 0.279" @ 10-inch from TB wall	Replaced all but 10-inch at wall

April 29, 2009: SIA was requested to inspect the piping that was not previously evaluated. In addition, Guided Wave™ did not find a hole in the 10-inch line. The vendor did not indicate that the data was potentially erroneous and issued results that were incorrect; they had not identified a through wall hole. The aluminum line had to have the coating completely removed to verify that there was no leakage. The guided wave provided inaccurate results.

April 29, 2009: A "window" containing the through- wall hole was sectioned from the two-foot segment of the 8-inch CS pipe and transported to PowerLabs for analysis. PowerLabs performed an assessment of the overall OD and ID condition prior to receiving the sample and in the laboratory. The laboratory analysis assessed the coating condition, identified the leak mechanism, determined the ID or OD initiation, and contributing factors.

April 29, 2009: The majority of the 8-inch and 10-inch buried piping was replaced (reference AR A2222268) and three remaining portions were evaluated via a technical evaluation (AR A2222268-13). An Operational Technical Decision-Making document was also prepared (ref IR 00907846-11) prior to startup from forced outage 1F20. Piping inspections performed during and following forced outage 1F20 indicated that the coatings on the 8-inch and 10-inch lines were inconsistently applied. The coatings were applied in a "patchwork" manner. Additionally, spark testing performed on these lines likely induced damage to the coatings on these lines. This indicated that the maintenance activities surrounding the repair and replacement activities were both 1) inadequate to mitigate corrosion on the affected piping, and 2) contributed to impairing coatings such that increased corrosion rates may have resulted.

May 5, 2009: An OTDM was prepared and included the following:
1-inch Condensate Transfer to Hotwell – CS (operating pressure: 22 psig)
Pressure testing of this line confirmed its integrity. This line is presently leak tight, but will be isolated when not in service to minimize any risk for future leakage. This line will be re-routed or replaced with material not susceptible to corrosion. The line can be isolated while the unit is on-line to support maintenance. This line will be used once for the start-up of the Condensate system and will be isolated following system start-up until a basis for future use is determined or an alternate routing is established.

1-inch Control Rod Drive (CRD) system Minimum Flow Bypass pipe to Condensate Storage Tank (CST) - stainless steel (operating pressure: 100 psig)
There is no evidence that this line is leaking. The line is stainless steel, which is less susceptible to corrosion. In 1993, Oyster Creek inspected two buried stainless steel lines. Records indicate that no degradation was found. This line was not inspected during 1F20 due to excavation restrictions caused by the excavation adjacent to the Condensate Transfer Pump Building.

4-inch Condensate Transfer Building Drain pipe - CS
A temporary plug was installed prior to startup to prevent leakage from the building. With the plug installed, the potential for leakage from this path is eliminated. The Condensate Transfer

Building Drain Line runs below grade and ties into the CST and Demineralized Water Tank Overflow Line. This is a 12-inch line that runs approximately seven feet below grade, entering the Turbine Building on the west wall and terminating (open ended) just above the Turbine Building floor about 20 feet below grade (ref. BR 2193 and BR 2180). For water to back up into the 4-inch line from the 12-inch line, the line would require significant flow (over 2000 gpm) to create enough of a backpressure in the 12-inch line to overcome the approximate 20 foot elevation difference between the Turbine Building floor and the Condensate Transfer Building floor. These flow rates are not likely to occur. Removal of this drain does increase the probability of a potential spill from a leak in the pump building. If a leak of sufficient magnitude develops, it could overflow the existing sump and mote area. The sump is equipped with a high level alarm. Increased attention to this potential is warranted. Line replacement will be performed, in the near term, as determined by the Buried Pipe program. A project has been initiated to improve the overall containment and management of the system within the Condensate Transfer Building (IR 914427)

6-inch Condensate Transfer Discharge aluminum piping (operating pressure 150 psig)
This piping was replaced in 1994. The coating inspection results indicate that the coating has not aged significantly since installation in 1994 and remains in good condition. No evidence of outside diameter (OD) corrosion was identified. Ultrasonic Testing (UT) inspection found minor inside diameter (ID) wall loss of approximately 8%. With the exception of four feet of pipe east of the Condensate Transfer Pump Building, the length of pipe from the Turbine Building to the Condensate Transfer Pump Building is visible. The four feet of pipe is covered by about two inches of loosely packed dirt. There was no observed leakage from this pipe section. The pipe has remained pressurized through the inspection period and leakage would be visible if present. Excavation and inspection efforts have been in progress since Saturday, April 25, 2009, and no signs of leakage have been identified. Coatings and wrappings shall be restored to design condition. The initial failure analysis on the 8-inch line concluded the failure was due to a coating breakdown causing OD to ID corrosion. There is no significant active damage mechanism occurring in this pipe.

8-inch diameter Hotwell Level Control to Hotwell (Carbon Steel) pipe (operating pressure 200-250 psig)
During inspection, a leak was identified in this pipe. The buried pipe will be replaced from near the Turbine Building wall to the above ground area in the Condensate Transfer Pump Building. The pipe between the turbine building wall and the new pipe will be inspected to ensure that no degradation exists in this short section. Coatings and wrap will be restored to design conditions.

10-inch diameter Hotwell Level Control to Hotwell carbon steel pipe (operating pressure 40 psig)
During restoration of the Condensate system, this line was pressurized and a leak developed in a portion of pipe. The buried pipe will be replaced from near the Turbine Building wall to the above ground area in the Condensate Transfer Pump Building. The pipe between the Turbine Building wall and the new pipe will be inspected to ensure that no degradation exists in this short section of pipe. Coatings and wrap will be restored to design conditions.

Condensate Storage Tank (CST) (Aluminum)
A walkdown of the area surrounding the tank does not indicate any leakage from the tank wall. Tank water level is being evaluated to determine if water level changes are proportional to operational condition requirements. CST inspections are scheduled to determine the condition of the floor of the tank for long-term operation. The divers are scheduled for May 4, 2009. Divers will perform full visual internal inspection of the tank bottom. Sixty random spots on the floor of the tank will be ultrasonically inspected. An ACMP is in place to monitor leakage to ensure that additional sources of active leakage do not exist.

The bottom of the CST was replaced in 1991. As part of this repair, the configuration of the bottom was improved to mitigate corrosion. This included caulking the interface between the tank bottom and the concrete base and improved drainage capability of the sand at the bottom of the tank.

May 7, 2009: IR 00916938 was written to capture an NRC recommendation that an additional monitoring well in the Kirkwood Aquifer (W-4K) be included in the monitoring program. The NRC recommended installing the well to provide assurance to the public that the on-site groundwater contamination is not migrating to off-site wells.

May 2009: PowerLabs analyzed the pipe sample per project number OYS-44923 with the following result: "The pipe leak was OD-initiated cause by localized galvanic corrosion initiated by a breach in the corrosion barrier coating."

May 2009: The Condensate Storage Tank was inspected during May 2009 per work order R2119514 in accordance with specification SP-1302-52-108. The work order closing remarks describe the results as satisfactory.

May 5, 2009: In an e-mail from PowerLabs to Exelon Engineering, additional details were described. "The pipe leak was OD-initiated and was associated with localized OD galvanic corrosion." The galvanic corrosion was caused by coating disbondment and progressive corrosion, as illustrated by a "halo" effect surrounding the through-wall hole. "Additional areas of localized OD pitting corrosion were observed and were associated with the primary leak location. The primary leak and associated damage were located within one quadrant on the pipe. The pattern is consistent with progressive coating disbondment. The extent of damage suggests that the corrosion has been occurring for an extended period.

No mechanical damage was observed on the pipe OD at or near the leak location. The ID pipe surface was pristine. The drawing marks from the original manufacture of the pipe were still easily visible, indicating no significant wall loss due to ID corrosion. The majority of the mastic coating had been removed. However, one piece remained at the end opposite the leak. The remnant piece was well-adhered with a thickness measuring 0.170". The remainder of pipe OD was in good condition, suggesting the general condition of the coating was adequate. For example, less than 1/2" from the "halo" associated with the leak original pipe stamping was clearly visible. The nominal wall thickness measured 0.328", consistent with 8-inch schedule 40 piping."

In conjunction with the above description and the Event and Causal Factor Chart (Attachment C of this report), the following causal factors were identified: 1) anodic dissolution resulting from disbondment of the coating and susceptible material; 2) a flawed program basis document; 3) inadequate work instructions, documentation, and work quality; 4) the change management processes prior to implementing the Exelon Buried Pipe Program did not support effectively managing design changes and related projects during site ownership and management changes; and 5) limitations in available technologies used to assess pipe material condition.

Extent of Condition:

Condition being addressed	Extent of Condition
Two buried piping lines in the Condensate System developed leaks, resulting in a release of tritium to the ground water.	The extent of condition is related to piping in the station's buried pipe program, as outlined in Attachment B of this report. The current risk to the organization is that other buried piping may have similar localized corrosion that is not being effectively managed because the methodologies used by the buried pipe program, which are consistent with industry best practices, are not locating the defects. There are three primary methods to identify degraded areas of piping that may develop leaks: Guided Wave™, UT, or excavation combined with direct inspection. The large number of components in the buried pipe program allows prioritized non-intrusive inspections to be used to collect information on the buried pipe population as a whole. Information gathered through internal plant experience dictates the need for direct examinations. The combined information from non-intrusive and direct inspections is used to implement long-term repairs and replacements. Examples of ways the station is addressing this condition are as follows: In 2008, Oyster Creek completed replacement of all underground safety-related ESW piping (approximately 600 linear feet). Risk ranking for these lines has been revised; the lines are no longer considered "High Risk." In 2004 and 2008, Oyster Creek replaced approximately 20% of all underground Service Water System piping (approximately 150 linear feet). In 2008, the program performed coating inspections on six lines in the area of the Reactor Building southeast vault. The inspection found that the coating on five lines was degraded and required repair. The deficiencies were entered into the station's Corrective Action Program (Issue Report (IR) 00813967). The IR was accompanied by an evaluation, which concluded that the coating conditions did not pose an immediate operability concern. Repairs are planned per work order R2130898. This inspection is now required as a repetitive task (PM57304M). This PM also opens and drains water out of the vault. In 2008, the program excavated and inspected a 6" Condensate Transfer line located west of the Turbine Building. The inspection found that the coating was in good condition.

Condition being addressed	Extent of Condition
	Upon entering the period of extended operation, focused inspections of buried piping and components will be performed on a ten-year frequency and as opportunities occur within this ten-year period. The inspections will include at least one carbon steel, one aluminum, and one cast iron pipe or component. In addition, for each of these materials, the locations selected for inspection will include at least one location where the pipe or component has not been previously replaced or recoated, if any such locations remain. The stainless steel piping in the vault will continue to be periodically inspected, and the bronze material is addressed by the buried carbon steel pipe coating inspections.

Analysis:

The investigation reviewed sources of tritium onsite, procedures for mitigating the risk of tritium releases to the environment, efforts to mitigate this risk, and organizational and programmatic effectiveness associated with tritium risk and impact mitigation. Following a comprehensive review of Buried Piping Program documentation ranging from site-specific technical documentation to industry operating experience, the Root Cause team used a combination of four different investigation techniques from Attachment 16 of, LS-AA-125-1001, "Root Cause Analysis Manual," to perform this evaluation. Event and Causal Factor Charts, TapRoot® Causal Factor Analysis, Barrier Analysis, and Cause and Effect Analysis were performed. The Root Cause team conducted interviews with Buried Piping Program Managers with both internal and fleet-wide experience, SIA representatives, and previous Maintenance department managers.

Analytical technique bases: TapRoot® Causal Factor Analysis was used to determine the cause categories and to accurately classify the root causes in a structured, documented approach. While TapRoot® is effective at identifying behavioral deficiencies, it may not lead to underlying causes. As such, Cause and Effect Analysis was used in conjunction with causal factor analysis to ensure that the investigation identified the underlying reasons for the event. A Barrier Analysis was performed to identify failed or ineffective barriers. These analyses are included as attachments to this document.

Through the methods listed above, the team identified two root causes and three contributing causes. Leaks that developed in the Condensate Transfer lines during 1991 were not addressed adequately to ensure an expected service life was achieved. Work quality was identified as a failed barrier using the event and casual factor and barrier analysis root cause methodologies. The work quality issues led to anodic dissolution of the pipe. In addition, the program initially placed an emphasis on Service Water, ESW, and Fuel Oil System buried lines due to these lines being initially ranked as having the highest degree of safety and environmental impacts. Interviews with the previous program owner indicated that the high risk ranking of the three systems drove the station to replace most of the buried lines of these systems with above ground or trenched lines. The remaining buried pipes were risk ranked and inspected as required by the buried piping program. The program basis document was developed with an erroneous assumption that a modification to the 8-inch carbon steel line was completed; the modification would have replaced the 8-inch carbon steel line with stainless steel. Based on this assumption, a lower risk ranking was assigned to this line with the consideration for stainless steel's resistance to corrosion. Associated design changes and documentation were not adequately controlled during the various change management processes that occurred over the course of the program's life.

Discussions were held with Exelon Corporate and site Engineers with experience in corrosion and buried piping to help investigate the corrosion mechanism. Initial discussions focused on galvanic corrosion. In general, galvanic corrosion is an electrochemical process that can occur when two dissimilar metals are in close proximity and are immersed in a substance that serves as an electrolyte or conductor. The electrolyte provides a means for ion migration whereby metallic ions can move from the anode to the cathode. This leads to the anodic metal corroding more quickly than it otherwise would; the corrosion of the cathodic metal is retarded, possibly even to the point of stopping any corrosion.

Given that some dissimilar metals were found in the area of the leak, general galvanic corrosion was considered as part of evaluating the primary failure mechanism due to known susceptibility to this phenomenon. For instance, some dissimilar metals found in the area of the leak include the following: 1) 8-inch carbon steel line CH-2a; 2) 10-inch carbon steel line CH-1c; 3) stainless steel clamps were attached to the 8-inch CH-2a carbon steel line in sections without pipe wrap; 4) abandoned aluminum piping approximately two feet above the 8-inch line; 5) copper grounding grid at the northwest corner of the turbine building.

Carbon steel and copper will undergo galvanic interaction when the two metals are both immersed in the same aqueous solution. The overall affect will be that the carbon steel will corrode.[1] The corrosion rate is affected by temperature; pH of the fluid, the amount and surface area of copper, the amount and surface area of carbon steel, and the distance between the metals. Anodic carbon steel (primary element is iron) and copper, which is noble, have an electrode potential of 0.777 volts. This is considered a galvanic couple in which the iron in the carbon steel will corrode.[2] A portion of the station's grounding grid is located on the west side of the Turbine Building. The grounding wires for this grid are mainly four feet below grade and are all copper. These wires are intended to electrically ground the Turbine Building and the station transformers. The copper wires are attached to grounding rods that are driven deep into the ground. Most of this grid is located to the south of the leaking lines (on the south side of the Condensate Transfer Building). However, two copper wires are located close to the 8-inch line on the north side of the Condensate Transfer Building. These two wires are on top of duct banks that traverse from the Condensate Transfer Building to the CST and to the Demineralized Water Storage Tank.[3] Comparing plant design drawings BR 3179 and BR 2193, the 8-inch and 10-inch lines are approximately 12 feet from these copper wires in the area where the leaks occurred. In addition, the Turbine Building grounding system has copper wires exiting the west wall of the Turbine Building near these lines.[4]

After review, it was determined that the spatial arrangement and electrical potential of these materials did not support development of a significant galvanic cell that would

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[1] Corrosion and Corrosion Control, Third Edition Uhlig and Revis, Wiley and Sons, 1984; Corrosion Engineering, Fontana, Third Edition, McGraw Hill, 1986; Corrosion Handbook, Uhlig, 1948, Wiley and Sons, 1984; NACE Corrosion Engineer's Reference Book, Library of Congress 79-67175

[2] Corrosion Engineering, Fontana, Third Edition, McGraw Hill, 1986; NACE Corrosion Engineer's Reference Book, Library of Congress 79-67175

[3] Plant drawings BR 3179, Rev. 9, and BR 2193, Rev. 10

[4] Plant drawings BR 3100, Rev. 3, BR 3180, Rev. 12, and BR E0805, Rev. 0

induce the degree of piping degradation identified on the carbon steel piping. The copper grounding grid was approximately 12 feet from the area of the degraded pipe. At this distance, a strong electrolyte would be needed to produce a significant coupling between the grid and the CS piping. The stainless steel (SS) clamps were electrically isolated from the CS by rubber matting applied between the clamp and the CS pipe. In addition, the bolts on the clamp appear to be CS and are not corroded. The SS galvanic potential is cathodic when compared to CS, but there is only a small difference in this potential. A CS-SS couple would be considered weak and the corrosion rate associated with such a couple would be considered too weak to develop the coupling required to induce the degree of piping degradation identified. Additionally, aluminum has a galvanic potential of -1.1 volts and the CS galvanic potential is -0.5 volts. This means that the aluminum, having a significantly higher galvanic potential, is more anodic and will selectively corrode over carbon steel. Abandoned aluminum piping in the area of the leak did not exhibit significant degradation as would be expected had galvanic coupling occurred.

With respect to Condensate System piping, anodic dissolution, a localized corrosion mechanism, occurred. Anodic dissolution resembles general galvanic corrosion in that the precursors include a coating defect and a material susceptible to electrochemical reduction. Anodic dissolution is a corrosion phenomenon that is characterized by a localized wall loss producing shear-walled, smooth-bottomed defects. This mechanism is typical in buried pipe systems where a defect in the coating of a pipe establishes a small anode that is driven by a large cathode. The adequately coated pipe acts as the cathode and, due to its size, produces a substantial driving force for corrosion. The relatively small anode is corroded at a rate that is proportional to the ratio of anode to cathode. Chemically, iron reacts with the hydroxide ion in water to form iron-hydroxide ($Fe(OH)_2$), leaving an excess of H^+ ions in the pit area. The suppression of pH results in the formation of H_2 gas through the combination of two H^+ ions in the reaction.

If anodic dissolution is occurring over a large area of dislodged coating, the corrosion footprint is different. The large area produces a wastage that is manifested as thinning over the entire area. The thinning is generally most severe at the center of the region of coating loss. The cross sectional profile slopes from the intact coating to the center defect or through-wall defect.

The following three scenarios are postulated to evaluate corrosion rates of the CS piping. Assuming that the 1991 coating repair and replacement was ineffective, the material would experience the onset of corrosion upon being direct buried. Also, had the 8-inch and 10-inch line pipe walls been repaired completely in 1991, and the wall thicknesses of both lines were nominal (sch. 40), the 8-inch line would have a nominal wall thickness of 322 mils. Based on the piping inspections during 1F20, a corrosion rate of 18 mils per year would be required for a through-wall leak to develop. Finally, some sections of the 8-inch line with thicknesses as low as .125 mils were not replaced in 1991.[5] Assuming the 8-inch and 10-inch line pipe walls were not completely repaired in 1991 and the wall thickness of the 8-inch line was allowed to remain with 0.125 mils, a corrosion rate of only seven mils per year would be required to produce a through-wall leak. Therefore, corrosion rates between seven and 18 mils per year could be postulated to produce a through-wall leak. CS immersed in soil (with no copper) will corrode in a range of 5 to 20 mils per year.[6]

An analysis of the site's Buried Piping program was conducted through a comparison of the Exelon Buried Piping Program procedures, ER-AA-5400 variety, and the program basis document, TR 116. Exelon implemented the Buried Piping and Raw Water Corrosion Program in 2007 through a pilot program using procedure ER-AA-5400 at four sites including Oyster Creek. The program called for a four-step methodology to monitor the condition of buried pipe. Step one is pre-assessment analysis. This step includes data collection including pipe design, construction details such as dates of modifications, pipe environment information, corrosion control methods, and operating data. Information gathered during this phase is reviewed to aid in the selection of the indirect inspection method.

The second part of the pre-assessment analysis is a risk assessment of the pipe. The susceptibility of outer corrosion based on environment and coating effectiveness is one aspect of the risk assessment. A pipe with high susceptibility of a leak is given a rating of a three while low susceptibility is ranked a one. The next aspect of the risk assessment is the consequence of a leak. A high consequence includes radiological consequences, environmental protection consequences, immediate affect on plant operations, or a repair costing over one million dollars. Medium consequences of a leak include an affect on supports of a juxtaposed system whose failure would result in a high consequence as discussed above or a repair costing more than five hundred thousand dollars. A buried pipe with low consequence is determined by exclusion when it does not fall into the high or medium consequence categories. As seen with susceptibility rankings, a high consequence pipe is ranked a three and a low is graded as a one. By multiplying the points given to the pipe for susceptibility and consequence, a risk rank is assigned to the component. The site's program basis document includes the risk ranking and should be updated each time the pipe is reclassified.

Step two of the buried piping program is the indirect inspection to identify anomalies along the piping system ranging from areas of corrosion to coating defects. Areas of the buried pipe are selected to be inspected using technologies such as guided waves based on susceptibility of the area to corrosion and accessibility to the chosen technologies.

Information collected through the indirect inspections are incorporated into the direct inspection process, step three of the buried piping program. Information collected during the indirect inspections is used to locate areas of lines that should be inspected

[5] Closure remarks for work order C0033031

[6] Corrosion Handbook, Uhlig, 1948, Wiley and Sons, 1984

using direct methods such as ultrasonic testing or a visual inspection with manual measurements. The following table from ER-AA-5400 details how the two inspection methodologies are related.

<u>Severe</u> - Initiate Direct Examination Plan with Contingencies for Mitigating Action	**<u>Medium</u> - Scheduled Action Required**	**<u>Minor</u> - Monitor**
Severe Indications in close proximity	Isolated Severe indication in a LOW Risk region	All remaining indications
Severe indications in region with multiple moderate indications	Groups of moderate indications	
Isolated Severe indications in HIGH Risk region	Groups of minor indications in MEDIUM Risk regions	
Indications known to be actively corroding		
Moderate indication in regions of prior severe corrosion, leaks, or HIGH Risk	Groups of Minor indications in close proximity	

The final step in the buried piping program is the post-assessment phase. Data collected from steps one through three is analyzed to determine corrective/preventative maintenance necessary, calculate wear rate, and determine the remaining life of the pipe. An example of this process is the 1-inch Condensate Transfer lines. Two direct buried 1-inch carbon steel lines run from the Turbine Building either to the Condensate Building or to the CST. One line runs between the Condensate Building and the Turbine Building (CS-26) and supplies flow from the Hotwell Level Control System to the Condensate Pump Seals, only during plant startup and shutdown. The other line runs from the northeast corner of the Turbine Building to the CST (CS-38) and provides minimum recirculation flow from the CRD Pumps.

These lines were assessed as a medium risk factor since they are direct buried and could result in an unmonitored radiological leak and possibly lead to a plant shutdown. Degradation of these lines will most likely be due to degradation of the coating and external corrosion of the carbon steel pipe wall. Based on plant operating experience the coating has the potential service life of 15 to 40 years and the pipe wall has the potential life of 4 to 15 years. Therefore, these lines should have a minimum service life of 19 years. Since these lines were inspected in 1993, they should be re-inspected, pressure tested, or replaced by 2012.

In 2007, these lines were considered for Guide Wave Inspection. Unfortunately the technology cannot inspect lines that are 1 inch in diameter or smaller. In addition, these lines are too short for "C Scan" Technology. IR 00861645 was submitted to pursue modification of these lines.

As indicated by the timeline, the above example, and the program basis document, Oyster Creek was implementing the Buried Piping Program as required per ER-AA-5400.

Root Cause Evaluation Report

Tritium Identified in Emergency Service Water (ESW) Vault

Evaluation:

Problem Statement	Cause (Describe the cause and identify whether it is a root cause or contributing cause)	Basis for Cause Determination
Two buried piping lines in the Condensate System developed leaks, resulting in a release of tritium to the ground water.	Root Cause 1 – Anodic dissolution resulting from disbondment of the coating and susceptible material	PowerLabs Report OYS-44923, "Evaluation of a Leak in Buried Condensate Piping for Oyster Creek Unit 1" identified the following: Analysis was performed on a section of the 8-inch line. The analysis concluded that the pipe leak was OD-initiated caused by localized galvanic corrosion initiated by a breach in the corrosion barrier coating. The galvanic corrosion caused additional coating disbondment and progressive corrosion, as illustrated by a "halo" effect surrounding the through-wall hole. Additional areas of localized OD pitting corrosion were observed and linked with the primary leak location. The primary leak and linked damage were located within one quadrant of the pipe. The pattern is consistent with progressive coating disbondment. Chlorine was detected at concentrations less than 1 wt.% in the external corrosion product on the pipe. The presence of chlorides can increase the corrosion rate. The extent of damage suggests this corrosion has been occurring for an extended period of time. No mechanical damage was observed on the pipe OD at or near the leak location. However, one piece remained at the end opposite the leak. The remnant piece was well-adhered with a thickness measuring 0.170". The remainder of pipe OD was in good condition, suggesting the general condition of the coating was adequate. For example, original pipe stamping was clearly visible less than ½"

Problem Statement	Cause (Describe the cause and identify whether it is a root cause or contributing cause)	Basis for Cause Determination
		from the leak 'halo'. The ID pipe surface was pristine. The drawing marks from the original manufacture of the pipe were still easily visible, indicating no significant wall loss due to ID corrosion. The nominal wall thickness measured 0.328", consistent with National Pipe Standard (NPS) 8-inch Schedule 40 piping." A 10-inch carbon steel line, CS-24, is direct buried between the Condensate Building and the Turbine Building. This line supplies flow from the Hot Level Control System in the Condensate Building to the Hotwell. The 10-inch line (CS-24) returns condensate from the CST via flow control valve V-2-16 to the Hotwell. Since this line is directly connected to all three Hotwells, it is under vacuum when the plant is at power. If a through wall hole develops in the pipe wall, leakage is drawn into the pipe and not out. Minimal condensate would be released to the surrounding soil. This line was assessed as a Medium Risk factor since it is a direct buried carbon steel line. This line was assessed as Medium Radiological Consequence factor since a leak could lead to an unmonitored release and a Medium Consequence factor since a significant leak could lead to a plant shutdown. Degradation of this line will most likely be due to degradation of the coating and external corrosion of the carbon steel pipe wall. Based on plant operating experience the coating has the potential service life of 15 to 40 years and the pipe wall has the potential life of 12 to 50 years. Therefore, these lines should

Root Cause Evaluation Report

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Problem Statement	Cause (Describe the cause and identify whether it is a root cause or contributing cause)	Basis for Cause Determination
		have a minimum service life of 27 years. Since this line was inspected in 1993, it should be inspected or pressure tested by 2020. The 8-inch CS line (SS-4/CS-25) is the Hotwell Level Control supply line from the Condensate Pump discharge header to flow control valve V-2-17. This line is pressurized to between 200 psig and 250 psig during normal operation. Upon developing a through-wall leak in the pipe, leakage would immediately exit the pipe and enter the surrounding soil. This line was assessed as having a Low Risk factor since it was assumed to be a direct buried SS line. This line was assessed a Medium Radiological Consequence factor since a leak could lead to an unmonitored release and a Medium Consequence factor since a significant leak could lead to a plant shutdown. The fact that the two lines developed leaks at the same time can be explained as follows: After plant shutdown on April 25, the Condensate system was secured, vacuum was broken on the Main Condenser, and the 10-inch line became positively pressurized from the head of water in the CST. At this time, it is believed that the line began to leak water from the Condensate system to the surrounding soil. The 10-inch line probably developed a through wall hole before the 8-inch line; however, because of the vacuum in the

Problem Statement	Cause (Describe the cause and identify whether it is a root cause or contributing cause)	Basis for Cause Determination
		line during normal operation, it likely did not release tritiated water to the surrounding soil until the Condensate System was secured.

Problem Statement	Cause (Describe the cause and identify whether it is a root cause or contributing cause)	Basis for Cause Determination
Two buried piping lines in the Condensate System developed leaks, resulting in a release of tritium to the ground water.	Root Cause #2 – The program basis document is flawed	Inadequate configuration management and design controls resulted in invalid assumptions that were used as the basis for development of the buried pipe program and the assessment of risk and consequences used to implement a strategic approach to tritium leak mitigation. Following the July 1991 leak on the 8-inch CS line, a modification was initiated to install flanged SS piping to replace CS piping from the Condensate Transfer Pump Building into the Condenser Bay and to reroute the piping from beneath the Condensate Transfer Building to outside. The modification was not implemented. However, GPU drawing 3D-421-22-1000, "Condensate System 8-inch CH-2 Partial Replacement," Revision 0, was issued documenting the design change. The bill of materials in this drawing, GU-3BM-421-50-1001, specifies that SS be used for the replacement pipe. The modification process at the time did not provide for requiring that the design documentation and the in-field installation of the modification be inextricably linked. In this instance, approval and issuance of the related design documents occurred separate from, and without coordination with, actual in-plant installation of the modification in drawings labeled as "INTERIM." This configuration management issue was not discovered until the discovery of tritiated water leak in 2009. Issue Report 00919332 was initiated to document this discrepancy.

Root Cause Evaluation Report

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Problem Statement	Cause (Describe the cause and identify whether it is a root cause or contributing cause)	Basis for Cause Determination
		Based on design drawing 3D-421-22-1000, it was thought that the 8-inch line was SS. This assumption was included in the Buried Pipe program basis document as illustrated in TR-116, Appendix 4, "Inventory of Risk and Consequence Significant Lines – Stainless Steel Pipe." In fact, a work order to perform coatings inspections on Condensate piping in 2008 describes an 8-inch stainless steel line to be excavated as part of the work activity. Also included in the program basis document was an assumption that coatings were replaced on the CS piping and that a 15-year life expectancy was valid for these coatings. This assumption was based on work order C0033031. In addition, a degradation rate was determined for the piping based on service life and expected corrosion rates. Life expectancy for these lines was determined by adding the coating life expectancy to the service life expectancy for the piping. For example, the coating on the 8-inch CS line had a postulated service life of 15 years. Based on corrosion rates, the piping service life was expected to be 15 years. Based on these assumptions, the service life of this line was determined to be 30 years.
Two buried piping lines in the Condensate System developed leaks, resulting in a release of tritium to the ground water.	Contributing Cause #1 – Inadequate work instructions, documentation, and work quality	In September 1991, an Engineering evaluation was performed and documented in P.E. 125-1 File No. 1001-91, "Coating Repair on 1-inch, 8-inch and 10-inch CS Underground Condensate Lines." This evaluation supported the visual inspection of the pipe coating, with actions to perform the following: 1) "mark the area(s) to be recoated;" 2) "remove

Problem Statement	Cause (Describe the cause and identify whether it is a root cause or contributing cause)	Basis for Cause Determination
		the existing coating at these areas;" 3) "using manual prying tools, peel off non-adhering coatings from the UT inspection and other suspect areas;" 4) "Perform a spark test on the remaining coating;" 5) "Apply two coats of Devoe Bar Rust 235 epoxy coating..." With respect to pipe preparation, the evaluation states that the final surface preparation "shall meet the commercial grade blast cleaning requirements of SSPC-SP6." Work order C0033031 was initiated to perform these activities. Closure comments in the work order inadequately document the as-found condition and conformance with guidance in the evaluation. For example, the work order states, "Pipe coating deteriorated. Pipe corroded req. repair/cleaning," which lacks specificity regarding characterization of the piping and corroded areas. Further, the closure comments do not document that pipe preparations were conducted in accordance with SSPC-SP6; to the contrary, the work order notes that the pipe coating was removed and replaced in accordance with Engineering direction, and references Maintenance procedure 1000-ADM-1100.07, "Abrasive Blasting Safe Work Procedure, but not SSPC-SP6. The work order specified that spark testing be performed on the 8-inch and 10-inch lines. The work order does not specify a voltage for this testing and does not cite a reference for conducting the testing. This is significant in that ASTM D5162 - 08, "Standard Practice for

Problem Statement	Cause (Describe the cause and identify whether it is a root cause or contributing cause)	Basis for Cause Determination
		Discontinuity (Holiday) Testing of Nonconductive Protective Coating on Metallic Substrates," notes that coatings that are applied at a thickness of less than 0.5 mm (20 mil) may be susceptible to damage if tested with high voltage spark testing equipment. To prevent damage to a coating film when using high voltage test instrumentation, total film thickness and dielectric strength in a coating system shall be considered in selecting the appropriate voltage for detection of discontinuities. Atmospheric conditions shall also be considered since the voltage required for the spark to gap a given distance in air varies with the conductivity of the air at the time the test is conducted." The work order does not document that any consideration was given. From this testing, five small areas on the 10-inch line were identified as requiring repair. On the 8-inch line, two areas, totaling approximately two square feet, required repairs. A review of work order closure identified that repairs were limited to the relatively small areas identified as requiring either coating or pipe repairs. It is noteworthy that these maintenance activities did not remove all coatings for visual and/or UT inspections on the entirety of the exposed pipe. Such inspections would have allowed a more rigorous examination, particularly given that several pipes were identified as having some degree of degradation and since the 10-inch CS line had multiple holes, indicating the potential for

Root Cause Evaluation Report

Tritium Identified in Emergency Service Water (ESW) Vault

Problem Statement	Cause (Describe the cause and identify whether it is a root cause or contributing cause)	Basis for Cause Determination
		extensive corrosion of the pipe. Consistent with the point-by-point examination, the repairs of the piping and coating were performed in a "patchwork" manner. Formal documentation for some changes was not used to establish quality records for retention, resulting in a lack of/inaccurate documentation around pipe configuration, configuration changes, soil and material condition, and abandoned pipe. Work Order closing remarks reviewed as part of the investigation did not include adequate descriptions of work completed. Notations in work order CREM are vague and interpretation could have altered the meaning of the notes. Work Orders had incomplete references to vendor manuals and procedures. Examples exist where references made in work orders could not be followed to a retrievable document. Underground piping program drawings may not have been updated and properly maintained as part of modifications. The 6-inch line was replaced in 1994, but BR-2193 was not updated to reflect the modification. The 8-inch line, SS-4, was not replaced and has no postings. Work Order C0032859 specifies that Engineering is to be involved in determining the proper method for repair of the line based on inspection results. There is no documentation that Engineering evaluated the repair of this line. A non-conforming condition was

Problem Statement	Cause (Describe the cause and identify whether it is a root cause or contributing cause)	Basis for Cause Determination
		identified as MNCF 91-0242; however, the work order closure remarks do not document the specific non-conformance. The documented cause of failure is listed simply as "pipe corrosion;" no additional investigation of cause or extent of condition is documented.
Two buried piping lines in the Condensate System developed leaks, resulting in a release of tritium to the ground water.	Contributing Cause #2 – The change management processes prior to implementing the Exelon Buried Pipe Program did not support effectively managing design changes and related projects during site ownership and management changes	The station had several changes of ownership and management between the time the leaks were identified in 1991 and the 2009 leaks. During this dynamic era, the Buried Pipe program began and evolved with changes in procedures and processes that governed its implementation. A station-specific program was implemented in 1991. The initial focus of the program was on Service Water and Emergency Service Water systems due to their implications for plant safety. Additionally, fuel oil piping was a primary focus due to environmental concerns. Several modifications aimed at mitigating the station's risk to underground tritium leaks were planned, including design changes to move lines above ground, move piping into concrete trenches, and to replace lines using more corrosion-resistant materials. In most instances, these planned modifications were in response to identified leaks. Inadequate configuration management and design controls resulted in invalid assumptions that were used as the basis for development of the program, the associated assessment of risks and consequences, and, consequently, the station's strategic approach to tritium leak

Problem Statement	Cause (Describe the cause and identify whether it is a root cause or contributing cause)	Basis for Cause Determination
		mitigation. The station missed opportunities to properly characterize risks and consequences associated with the degraded Condensate System piping. These risks and consequences were developed as part of the program basis document. The program basis document is flawed in that the 8-inch Condensate line was incorrectly identified as stainless steel as opposed to the installed CS piping. In addition, management decisions were made in the mid-1990s to allow the station's operating license to expire.
Two buried piping lines in the Condensate System developed leaks, resulting in a release of tritium to the ground water.	Contributing Cause #3 – Limitations in available technologies used to assess pipe material condition.	The combined information from non-intrusive and direct inspections is used to identify the need for long-term repairs and replacements. The inspections rely on available technologies, each of which has specific limitations. This includes Visual Inspection, Ultrasonic Testing (UT), Guided Wave™, and C-Scan™ inspections. Any of these methods alone would not allow for 100% assurance of pipe integrity. Instead, they are used in combination to find localized areas of concern. Since 100% verification of pipe integrity is not practical, even these extensive measures leave vulnerable to localized corrosion because the methodologies used by the buried pipe program do not, in all instances, locate existing defects and cannot assess entire continuous full lengths of pipe.

Problem Statement	Cause (Describe the cause and identify whether it is a root cause or contributing cause)	Basis for Cause Determination
		For example, a UT examination typically covering just a few linear feet of large diameter pipe can take several hours, and requires an additional shift or more to properly prepare the pipe surface prior to the inspection. This makes UT inefficient in assessing the condition of a piping system; consequently, this method is not efficient with respect to finding wall thinning before it leaks. In the case of buried pipe, costly and time consuming excavation would be required for complete OD access to the piping, or equally challenging operational and configuration changes would be required to allow complete ID access. The industry considers Guided Wave™ technology to be an acceptable means to perform quick non-intrusive inspections of long sections of pipe to identify degradation. However, industry experience has shown that at the current level of development, even the most sophisticated indirect inspection methods are not as accurate at sizing the axial and circumferential extents of a corroded area as UT and, as a result, a follow-up direct examination such as UT would be required to characterized the area of corrosion.

Extent of Cause:

Cause being addressed	Extent of Cause
Root Cause #1 – Anodic dissolution resulting from disbondment of the coating and susceptible material	There are currently 25 buried piping lines that carry tritiated water. A lack of detail surrounding the work details and practices leaves the lines open to poorly applied coating; as seen with SS-4 and CS-24, this may make the current underground piping susceptible to corrosion. Corrosion may lead to through wall degradation and result in a release of tritium into the ground water. The programmatic controls for these lines are listed in Attachment B: Oyster Creek Buried Piping Program Description and Status.
Root Cause #2 – The program basis document is flawed.	This cause is limited to the Buried Piping Program at Oyster Creek. There is no further extent of cause.
Contributing Cause #1 – Inadequate work instructions, document, and work quality	Work quality inadequacy is a site wide problem that affects activities completed during the on-line and outage work schedules. This can extend the scheduled times for activities and may result in work being completed incorrectly.
Contributing Cause #2 – The change management processes prior to implementing the Exelon Buried Pipe Program did not support effectively managing design changes and related projects during site ownership and management changes	Formal documentation deficiencies have been identified at the site ranging from lack of detail in the closing remarks of work orders to some design documents not accurately reflecting the conditions in the plant. During the license renewal process, the project team initiated a standardized format for work order closure remarks in an effort to improve the formalized documentation process. Work package quality was identified as a contributing cause to the 5-day extension of the 2008 Refueling Outage. Inadequate documentation can affect the health of both systems and programs and provide the site with ineffective inspection schedules that can, in turn, lead to undetected degraded conditions in the field.

Cause being addressed	Extent of Cause
Contributing Cause #3 – Limitations in available technologies used to assess pipe material condition.	Industry experience has demonstrated the limitations of even the most sophisticated technology, such as Guided Wave™ for performing indirect inspections. UT examinations are effective in detecting localized areas of corrosion, but are inefficient for assessing long sections of large piping since this method is costly and time consuming. The site is vulnerable to localized corrosion because the methodologies used by the buried pipe program do not, in all instances, locate existing defects and cannot assess entire continuous full lengths of pipe. Incorporation of high quality inspection methods into the program of condition assessment and long-term strategic planning is an imperative to effectively address questions of overall pipe integrity.

Risk Assessment:

PLANT-SPECIFIC RISK CONSEQUENCE	BASIS FOR DETERMINATION
Industrial Safety	There is a moderate risk of industrial safety issues caused by the leaking pipes. The inspection excavation and repair of the underground piping exposes workers to a construction environment with its inherent dangers.
Nuclear Safety	There is no increase in risk from a nuclear safety perspective. The leaks in the 8-inch and 10-inch condensate transfer lines did not affect the plant's ability to safely shut down. In the event of an incident, the plant equipment would have functioned normally and the plant would have been shut down safely.
Chemical/ Radiological/Environmental	There is a small radiological risk associated with the underground pipe leaks. The leaking water spread radioactive contamination to the environment. The water contained tritium that produces a low energy beta dose.
Regulatory Impact	The tritium level in the water that was leaking from the pipes was above the reporting limits for the State of New Jersey (2,000 pCi/L) based on a voluntary verbal agreement with the New Jersey Department of Environmental Protection. The Environmental Protection Agency's reportable quantity is 100 Ci per 40 CFR Part 302.
Production Cost	There is no increase in production cost risk.

Root Cause Evaluation Report

Tritium Identified in Emergency Service Water (ESW) Vault

Equipment Checklist:

Step 1 **Run To Failure (RTF) Classification Check**
Is the component **incorrectly** classified as Critical, Non-Critical or Run-to-Failure per MA-AA-716-210? No

Step 2 **PM/PDM Review**
Has the past PM/PDM **not** been performed in accordance with the PCM template? No PCM Template was found for Buried Piping, only Cathodic Protection.

Step 3 **Maintenance Performance Assessment**
Is there a deficiency with the performance of the most recently performed maintenance? Yes, compared to today's requirements.

Step 4 **Performance Monitoring Assessment**
Has system/component monitoring been deficient in identifying normal or abnormal equipment degradation? Yes, see Timeline for details.

Step 5 **Operating Experience Review**
Is there a deficiency in how past operating experience (OPEX) applicable to this component has been addressed? No, risk ranking included a review of applicable OPEX.

Step 6 **PCM Template Review**
Is there a deficiency in any PCM template applicable to this component? Preventative Maintenance is part of the program and not covered through the PCM Template. Cathodic Protection is not utilized at the site, so the PCM Template for it does not apply.

Step 7 **Operational Performance Review**
Are the operating procedures or practices for this component inappropriate or unacceptable? They are acceptable per the Buried Piping Program.

Step 8 **Maintenance Practice Review**
Are there problems with the maintenance practices, behaviors or training for this component? There is no training for coating applications. This is addressed in the corrective actions section of the report.

Step 9 **Design Review**
Is the design configuration for this component incorrect? This is addressed in the cause and corrective action sections of the report.

Step 10 **Manufacture/Vendor Quality Check**
Is there a concern with the quality of parts, shipping or handling? No

Step 11 **Problem/Issue Management Review**
Have previous issues not been adequately addressed including but not limited to aging, obsolescence, chronic problem, scheduling, or business planning? The inspections were based on risk assessments made and effectively managed based on the assumption that the risk assessments were correct.

Step 12 **Latent Weaknesses**
Document in the investigation report whether the event should have been

reasonably prevented by improved work preparation, effective troubleshooting, or management oversight. See Attachment 7 for guidance. This is documented throughout the report.

Step 13 **Unknown or Different Cause**

Did the equipment fail due to an unknown cause or other cause than listed in steps 1 through 11 above? No

Previous Events:

PREVIOUS EVENTS	PREVIOUS EVENT REVIEWS
There are 23 documented Significant Underground Pipe leaks in Appendix 1 of the Oyster Creek Underground Piping Program Description and Status, Topical Report 116, Rev.3. Leaks are documented from 1980 to present.	The leaks documented were caused by various mechanisms and the affected piping was repaired, replaced and/or relocated. The underground piping program used these leaks to prioritize and rank pipes for monitoring, inspections and testing going forward. There will be improvement recommendations for the program as part of this root cause.
OE 10250 Perry. Underground Drisco Pipe Failure. 07/01/1999	This OE was reviewed for common items. The leaking pipe was an air line that had been damaged during installation. This reinforced the need to ensure proper techniques are used to install or repair underground piping. The piping leak at Oyster Creek had external coating that was not installed correctly after maintenance leading to corrosion and failure.
OE 16189 Brunswick. Underground Fuel Oil Line Leak. 04/03/2003	This OE review showed that degraded pipe coating led to corrosion and eventual failure of an underground pipe. The corrosion was accelerated by past salt water leaks in the area. This is good OE to ensure that all effects of leaks like salt water are investigated and resolved.

PREVIOUS EVENTS	PREVIOUS EVENT REVIEWS
OE 22409 Braidwood Station Identified Low levels of Elevated Tritium in the groundwater on and offsite. 04/19/2006	The Braidwood tritium event sensitized the company and industry to the importance of acting quickly to identify and mitigate the effects of tritiated water leaks. Oyster Creek proactively sampled water in the ESW vault for tritium. Once identified, the appropriate actions were taken to identify the source, repair the leaking pipe and develop plans to mitigate the contaminated ground. Braidwood completed Root Cause Report under Passport ATI 428868. Exelon established a program to evaluate the potential of unplanned tritium releases at each of its facilities. A fleet Nuclear Event Report (Passport ATI 428868 Assignment 12) required all Exelon sites to take actions to research historical spills and determine if tritium remediation is required. The industry was informed of the issues through a Nuclear Network Operating Experience Report (Passport ATI 428868 Assignment 13).
Operating Experience Digest (OED 2007-09) External Degradation of Buried Piping. 4/2007	This OE Digest summarizes areas for improvement (AFIs) written because of weaknesses noted in protecting buried piping. This is a good reference document reviewed for areas in the Oyster Creek program that could be improved. One item of note is the Self-Review questions regarding buried piping. This section should be used to help develop the FASA/Check in template that will be written for the program.

PREVIOUS EVENTS	PREVIOUS EVENT REVIEWS
OE 27146 Quad Cities. Underground Pipe Leak due to Possible Crevice Corrosion. 5/28/2008	This OE review showed that shoring left in an excavation led to crevice corrosion and failure of an underground pipe. The shoring was a cable spool that had been used to separate a pipe above the failed pipe during maintenance activities 15 years prior to the event. The spool was in contact with the pipe and created a crevice that allowed corrosion. This is good OE to ensure that all shoring bracing or other debris is removed from excavations prior to back filling.
OE 27897 Davis-Besse. Three-Inch Buried Pipe Degradation Results in Leak of Tritium into Ground. 10/22/2008	This OE was very similar to the Oyster Creek leak. The pipe in question had degraded coating, which led to corrosion and eventual leak. This event was noteworthy because degraded piping and inadequate monitoring of pipe integrity contributed to underground piping failure.
OE 28335 Indian Point. Leaking Underground Condensate Return Line Pipe. 02/15/2009	This OE was another example of a degraded external wrap that led to corrosion and failure of an underground pipe. This event was noteworthy because degraded piping and inadequate monitoring of pipe integrity contributed to underground piping failure.

Root Cause Evaluation Report

Tritium Identified in Emergency Service Water (ESW) Vault

Immediate Actions:

Immediate Actions Taken or Planned (Include AT Assignment #)		Owner	Due Date
IR written to document the discovery of tritium in the Emergency Service Water Vault.	IR 00907846	Matt Nixon	Complete
Created PIMS AR from IR 00907846 to track all work orders initiated to locate and repair the source of the tritium leak	PIMS AR A2222268	Ralph Larzo	Complete
Perform a Prompt Investigation and obtain management approval. After approval, submit the PINV to the NDO Mailbox and the NRC Resident.	IR 00907846 Assignment 2	Philip Olivieri	Complete
Evaluate all inputs into and from the ESW vault for potential sources of tritium and inspect other vaults in the vicinity and sampling for tritium as warranted	IR 00907846 Assignment 2	Philip Olivieri	Complete
Collect water samples from: Monitoring wells in the general vicinity of the cable vault: W-3, W-4, W-5, W-6 and MW-15K-1A along with Lysimeter in the vicinity of the cable vault (CST-9), and the Lysimeter on the southwest corner of the Condensate Storage Tank (CST-2). Monitor surface water sample from the Main Condenser discharge.	IR 00907846 Assignment 2	Philip Olivieri	Complete

Root Cause Evaluation Report

Tritium Identified in Emergency Service Water (ESW) Vault

Immediate Actions Taken or Planned (Include AT Assignment #)		Owner	Due Date
Ship the samples to Teledyne Brown Engineering to be analyzed for tritium, strontium-90 and gamma emitting radionuclides utilizing the detectable limits (LLDs) specified for the Radiological Groundwater Protection Program.	IR 00907846 Assignment 2	Philip Olivieri	Complete
Install temporary clamp repair on the identified leaks	Work Order C2021073	Maintenance Work Support	Complete
Drill sample wells per digging permit	Work Order C2021076	Jingoli Environmental	Complete
CS-26 and CTB drain line inspection	Work Order C2021083	Jingoli Maintenance	Complete
Inspect and repair if necessary the 1-inch condensate pipe	Work Order C2021104	Maintenance	Complete
Repair/Replace the 8-inch condensate pipe	Work Order C2021105	Maintenance	Complete
Repair/Replace the 10-inch condensate pipe	Work Order C2021108	Maintenance	Complete
Prepare and issue OTDM for the leak in the condensate transfer system	IR 00907846 Assignment 11	Roger Gayley	Complete

Corrective Actions to Prevent Recurrence (CAPRs):

Root Cause Being Addressed (Include TapRoot Codes)	Corrective Action to Prevent Recurrence (CAPR) (Include AT Assignment #)	Owner	Due Date
Anodic dissolution resulting from disbondment of the coating and susceptible material. *(Corrective Action Needs Improvement 5CL)*	CAPR Passport ATI 907846 Assignment 14: Implement a strategic plan that includes moving direct buried Condensate and Condensate Transfer System piping either above ground or in monitored trenches (Root Cause 1)	Kevin Leonard	December 17, 2010 (Fall 2010 refueling outage 1R23)
The Program Basis Document is Flawed *(SPAC has a Technical Error 5TE)*	CAPR Passport ATI 907846 Assignment 15: Perform a thorough program assessment and revise the program basis document (i.e., TR-116) to correct errors in plant design details, risks, consequences, and recommend inspection frequencies and methods following the assessment (Root Cause 2)	Kevin Leonard	September 25, 2009

Corrective Actions:

Cause Being Addressed (Include TapRoot Codes)	Corrective Action (CA) or Action Item (ACIT) (Include AT Assignment #)	Owner	Due Date
Root Cause #1: Anodic dissolution resulting from disbondment of the coating and susceptible material. *(Corrective Action Needs Improvement 5CL)*	CA Passport ATI 907846 Assignment 16: Site Design Engineering develop engineered solutions for bringing buried piping above ground or entrenching the pipes.	Howie Ray	December 11, 2009
	ACIT Passport ATI 907846 Assignment 17: Perform an extent of condition review for maintenance performed on direct buried piping prior to implementation of the Exelon Buried Pipe Program	Thomas Roddey	August 28, 2009
Root Cause #1: Anodic dissolution resulting from disbondment of the coating and susceptible material. *(Preventative Maintenance Needs Improvement 4PL)*	ACIT Passport ATI 907846 Assignment 18: Evaluate installing sacrificial anodes/impressed current to mitigate galvanic corrosion and present to PHC.	Kevin Leonard	October 30, 2009
	ACIT Passport ATI 907846 Assignment 19: Clearly document As-Left conditions of buried piping in the program basis document.	Kevin Leonard	October 30, 2009
Root Cause #2: The program basis document is flawed. *(SPAC has a technical error 5TE)*	ACIT Passport ATI 907846 Assignment 20: Review work packages associated with the 2009 leak for adequate closure documentation, documentation of as-left conditions, and documentation of compliance with guidance documents for the work performed	Kevin Leonard	July 31, 2009

Cause Being Addressed (Include TapRoot Codes)	Corrective Action (CA) or Action Item (ACIT) (Include AT Assignment #)	Owner	Due Date
	ACIT Passport ATI 907846 Assignment 21: Maintenance Curriculum Review Committee evaluate the need for work group training on buried pipe coating application.	Paul Matterson	September 25, 2009
	ACIT Passport ATI 907846 Assignment 22: Engineering Curriculum Review Committee evaluate the need for work group training on buried pipe coating application.	Chris Lefler, Sr.	September 25, 2009
Contributing Cause #1: Inadequate work instructions, documentation, and work quality *(Work Package/Permit Needs Improvement 5WP)*	CA Passport ATI 907846 Assignment 23: Institutionalize guidance to document As-Left conditions in work order closure documentation following excavations	Sullivan	August 28, 2009
Contributing Cause #1: Inadequate work instructions, documentation, and work quality *(Standards, Policies, or Administrative Controls are Not Strict Enough 5NS)*	ACIT Passport ATI 907846 Assignment 24: Maintenance Curriculum Review Committee evaluate the need for work group training on work order closure quality.	Conley	September 25, 2009
	ACIT Passport ATI 907846 Assignment 25: Engineering Curriculum Review Committee evaluate the need for work group training on work order closure quality.	Chris Lefler, Sr.	September 25, 2009

Cause Being Addressed (Include TapRoot Codes)	Corrective Action (CA) or Action Item (ACIT) (Include AT Assignment #)	Owner	Due Date
Contributing Cause #2: The change management processes prior to implementing the Exelon Buried Pipe Program did not support effectively managing design changes and related projects during site ownership and management changes. *(Standards, Policies, or Administrative Controls are Confusing or Incomplete 5CI)*	CA Passport ATI 907846 Assignment 26: Incorporate signatures for Engineering inspection/approvals for pipe repair and replacement in work orders to ensure the desired results through maintenance are being achieved.	Sullivan	August 28, 2009
Contributing Cause #2: The change management processes prior to implementing the Exelon Buried Pipe Program did not support effectively managing design changes and related projects during site ownership and management changes. *(Standards, Policies, or Administrative Controls has a Technical Error 5TE)*	CA Passport ATI 907846 Assignment 27: Update buried piping design documents to as-built conditions	Abruscato	December 18, 2009

Cause Being Addressed (Include TapRoot Codes)	Corrective Action (CA) or Action Item (ACIT) (Include AT Assignment #)	Owner	Due Date
Contributing Cause #2: The change management processes prior to implementing the Exelon Buried Pipe Program did not support effectively managing design changes and related projects during site ownership and management changes. *(Employee Communications Needs Improvement 5EC)*	ACIT Passport ATI 907846 Assignment 28: Review the Oyster Creek buried piping database for inaccuracies	Kevin Leonard	September 28, 2009
Contributing Cause #2: The change management processes prior to implementing the Exelon Buried Pipe Program did not support effectively managing design changes and related projects during site ownership and management changes. *(No Standard Turnover/Transition Process Exists 5TP)*	CA Passport ATI 907846 Assignment 29: Update the Oyster Creek buried pipe database following reviews completed per Passport ATI 907846 Assignment 28	Kevin Leonard	September 28, 2009
Contributing Cause #3 – Limitations in available technologies used to assess pipe material condition *(Technological Limitations 1Z)*	ACIT Passport ATI 907846 Assignment 30: Review Guided Wave and Ultrasonic results from previous inspections for indications of non-conservative results.	Kevin Leonard	October 16, 2009

Effectiveness Reviews (EFRs):

CAPR / CA Being Addressed	Effectiveness Review Action (Single/Collective) (Include AT Assignment #)	Owner	Due Date
CAPR Passport ATI 907846 Assignment 14: Implement a strategic plan that includes moving direct buried Condensate and Condensate Transfer System piping either above ground or in monitored trenches	EFR Passport ATI 907846 Assignment 31: Determine the acceptance criteria for the amount of Condensate and Condensate Transfer System piping that remains direct buried without inclusion in the strategic plan following 1R23; measure effectiveness against this criteria.	Kevin Leonard	December 4, 2009
CAPR Passport ATI 907846 Assignment 15: Revise the program basis document (i.e., TR-116) to correct plant design details, risks, consequences, and recommend inspection frequencies and methods following a thorough program assessment.	EFR Passport ATI 907846 Assignment 32: Monitor the health of the program against current performance indicators for improvements after the program basis document has been corrected.	Kevin Leonard	July 15, 2010

Programmatic/Organizational Issues:

Programmatic and Organizational Weaknesses (Causal Factor)	Corrective Action (CA) or Action Item (ACIT) (Include AT Assignment #)	Owner	Due Date
The Program basis document is flawed.	ACIT Passport ATI 907846 Assignment 33: Develop a schedule for periodic focused area assessments of the site's buried pipe program on a set frequency.	Kevin Leonard	July 17, 2009

Root Cause Evaluation Report

Tritium Identified in Emergency Service Water (ESW) Vault

Other Issues:

Other Issues identified during investigation	Corrective Action (CA) or Action Item (ACIT) (Include AT Assignment #)	Owner	Due Date
All issues adverse to quality were identified in the body of the report.	No additional corrective actions are required.	N/A	N/A

Communications Plan:

Lessons Learned to be Communicated	Communication Plan Action (Include AT Assignment #)	Owner	Due Date
Root and Contributing Causes of this event.	NNOE Passport ATI 907846 Assignment 13: Communicate a summary of this root cause report to the appropriate parties via NNOE.	Thomas Roddey	Complete

Attachments:

	Title
A	Root Cause Report Quality Checklist
B	Oyster Creek Buried Piping Program Description and Status
C	Event and Causal Chart
D	Why Staircase
E	Condensate Transfer Lines As-Found Condition
F	Three Mile Island Anodic Dissolution Photographs

Root Cause Evaluation Report

Tritium Identified in Emergency Service Water (ESW) Vault

Attachment A
Root Cause Report Quality Checklist
Page 1 of 2

A.	Critical Content Attributes	YES	NO
1.	Is the condition that requires resolution adequately and accurately identified?	Yes	
2.	Are inappropriate actions and equipment failures (causal factors) identified?	Yes	
3.	Are the causes accurately identified, including root causes and contributing causes?	Yes	
4.	Are there CAs to prevent recurrence identified for each root cause and do they tie DIRECTLY to the root cause? AND, are there CAs for contributing cause and do they tie DIRECTLY to the contributing cause?	Yes	
5.	Have the root cause analysis techniques been appropriately used and documented?	Yes	
6.	Was an Event and Causal Factors Chart properly prepared?	Yes	
7.	Does the report adequately and accurately address the "extent of condition" in accordance with the guidance provided in Attachment 4 of LS-AA-125-1003?	Yes	
8.	Does the report adequately and accurately address the "extent of cause" in accordance with the guidance provided in Attachment 4 of LS-AA-125-1003?	Yes	
9.	Does the report adequately and accurately address plant specific risk consequences?	Yes	
10.	Does the report include the Equipment Checklist, per LS-AA-125-1003 for equipment Root Causes?	Yes	
11.	Does the report adequately and accurately address behavioral, programmatic and organizational issues?	Yes	
12.	Have previous similar events been evaluated? Has an Operating Experience database search been performed to determine useful lessons learned or insights for development of corrective actions?	Yes	
13.	Check applicable SOER recommendation responses to see if a required revision is necessary based on the results of the RCR.	N/A	N/A
14.	If required, does the report adequately address the NRC's Safety Culture Components in accordance with the guidance provided in Attachment 20?	N/A	N/A

Attachment A
Root Cause Report Quality Checklist
Page 2 of 2

B.	Important Content Attributes	YES	NO
1.	Are all of the Important facts included in the report?	Yes	
2.	Does the report explain the logic used to arrive at the conclusions?	Yes	
3.	If appropriate, does the report explain what root causes were considered, but eliminated from further consideration and the bases for their elimination from consideration?	Yes	
4.	Does the report identify contributing causes, if applicable?	Yes	
5.	Is it clear, what conditions the CAs are intended to create?	Yes	
6.	Has the scope identified in the RC Charter been adequately addressed during the RCA investigation and documented in the report? If not, provide documented basis for deviation.	Yes	
7.	Do the CAs address the root causes or contributing causes without adding unnecessary actions?	Yes	
8.	Is the timing for completion of each CA commensurate with the importance or risk associated with the issue?	Yes	

C.	Miscellaneous Items	YES	NO
1.	Did an individual who is qualified in Root Cause Analysis prepare the report?		No
2.	Does the Executive Summary adequately and accurately describe the significance of the event, the event sequence, root causes, CAs, reportability, and previous events?	Yes	
3.	Was a Technical Human Performance screening review performed in accordance with HU-AA-1212, Technical Task Risk/Rigor Assessment, Pre-Job Brief, Independent Third Party Review, and Post-Job Brief?	Yes	
4.	Do the CAs include an effectiveness review for CAs to prevent recurrence?	Yes	
5.	Were **ALL** CAs entered and verified to be in Action Tracking?		No
6.	Are the format, composition, and rhetoric acceptable (grammar, typographical errors, spelling, acronyms, etc.)?	Yes	
7.	Have the trend codes been added or adjusted in Passport to match the investigation results?		No
8.	Are the appropriate attachments included, as identified in Attachment 13?	Yes	
9.	Was the Exelon Nuclear Corporate Functional Area Manger (CFAM) and Peer Group Processes, AD-AA-1110, Attachments 5 and 6, reviewed to document and evaluate best practices or improvement opportunities through the peer group process?		No

Attachment B: Oyster Creek Buried Piping Program Description and Status

ID	Description System/ Line size	Susceptibility	Consequence	Len.	Fluid/ Contamination	EL/ Depth	Draw.	Located	Inspections and Repairs	Action/ Basis
A-1	CH-3, 12" Condensate Transfer line from CST to Core Spray System and CRD system. AL 6061 Section 8.2.2.3 Last Inspected in 2007 (GW)	High	Medium	3'	Condensate	17'	2004 GE 885D781 237E487 4076 4079 2132 2138 2140	Between the TB and RB on Northwest corner of the RB,	In 1998 a project was performed to core bore the concrete slab above the gap in this area. A sample well was then installed under the condensate transfer line. The well showed that there was no moisture under the line. Soil samples indicated no condensate leak. Reference ETTS 4031 In 2007, this line was inspected using Guided Wave. Results were satisfactory.	Action: re-inspect by 2013
A-2	CH-5; 6" Condensate. Transfer from Turbine Building to pipe tunnel to the Reactor Building Al. 6061 **Section 8.2.2.5**	Medium	Medium	<10'	Demin Water/ Medium	19'	2195 2134 2004	Under Office Building.	This line was repaired in 1980. A vault was built around the line. This line is not direct buried Can only be inspected in 1 Refueling Outage	To be GW inspected in 2010 (IR 00686711)
A-3	NN-3 6" Fuel Pool Cooling line to Fuel Pool Filter in Radwaste – New line installed in 1993 Al. 6061	Low	Medium	<10'	Reactor Water/ Medium	19'	BR 2193 2153 GE 237E756	Central Vault /	This line was replaced in 1993, per BA 323721, OC-MM-323721-001, and SP-1302-12-268. Can only be inspected in 1 Refueling Outage	To be GW inspected in 2010 (IR 00686711)

ID	Description System/ Line size	Susceptibility	Consequence	Len.	Fluid/ Contamination	EL/ Depth	Draw.	Located	Inspections and Repairs	Action/ Basis
A-4	CH-5; 6" from the Condensate pumps to TB Al. 6061 **Section 8.2.2.2** **Last inspected in 2008 – Visual** **Also Inspected in 2007 per GW**	Medium	Medium	25'	Condensate Transfer	17'	2193 2132	Between the Condensate Transfer Building and the Turbine Building.	Original Vintage Piping. Original Plant underground line. However Coating Was repaired in 1992 In 2007, this line was inspected using GW. Results were satisfactory. Partially inspected in 2008 with good results	Excavate and inspect per ARA2116126 License Renewal Commitment

Appendix 4 - Inventory of Risk and Consequence Significant Lines - Stainless Steel Pipe

ID	Description System	Susceptibility	Consequence	Len.	Fluid/ Contamination	Coating/ Protection	EL/ Depth	Drawings	Located	Inspections and Repairs	Action
SS-1	SD-4A; 3" RWCU Demin Resin Sluice/ Resin Transfer to Radwaste SS 304 Section 8.2.3.2	Low-inspected in 1993	High	<15'	RWCU Resins	Coal TAR and Repaired Epoxy Coating w/ Nukon Wrap	18' -5'	2195 2143 148F444 sh13	Under the Office Building; Southwest of Reactor Building	Line was inspected and repaired as necessary in 1993 This line is used once per cycle. Can only be inspected in 1 Refueling Outage	To be GW inspected in 2010 (IR 00686711)
SS-2	SD-4C; 3" Condensate for RWCU Demin Resin Transfer SS 304 Section 8.2.3.2	Low-inspected in 1993	High	<10'	Condensate/medium	Coal Tar and Repaired Epoxy Coating w/ Nukon Wrap	18' -5'	2195 2143 148F444	Under the Office Building; Southwest of Reactor Building	Line was inspected and repaired as necessary in 1993 Can only be inspected in 1 Refueling Outage	To be GW inspected in 2010 (IR 00686711)
SS-	NV-2; 1 ½"	Low	Medium	<10'	Water	Coal Tar	12'	2195	Southeast Vault	A PM has been established to	To be GW

Appendix 4 - Inventory of Risk and Consequence Significant Lines - Stainless Steel Pipe

ID	Description System	Suscepti bility	Consequ ence	Len.	Fluid/ Cont amin ation	Coating/ Protecti on	EL/ Depth	Drawing s	Located	Inspections and Repairs	Action
3	Laundry drains to Radwaste SS 304/ 316 Inspected in 2008				/ Medium	and Repaired Epoxy Coating w/ Nukon Wrap	-11'	2184 GE 148F432		inspect coating of pipe in the southeast vault every 2 years (AR A2008369). Inspections of this line in 2001 and 2004 showed the coating is in good condition (CAP O2004-2071). Inspected in 2008	inspected in 2010 (IR 00686711)
SS-4	CH –2; 8-inch from TB to Sucker/Dumper Station; SS Replaced in 1992	Low	Medium	30'	Condensate	SS/Polyken Tape Tar	18'	2193 GU 3D-421-22-1000	From the Condensate Transfer Building to the TB west wall.	Turbine Building. Replaced in 1992 OC-MM-323643-001 GW Inspected in April 2009	To be GW inspected in 2010 (IR 00686711)

Appendix 4 - Inventory of Risk and Consequence Significant Lines - Carbon Steel Pipe

ID	Description System	Suscептibility	Consequence	Len.	Fluid/ Cont amin ation	Coating/ Protecti on	EL/ 1.2.1.	Drawing s	Located	Inspections and Repairs	Action
CS-1	ND-15; 1" Cleanup Sludge Transfer Line to sludge Tank A106 **Section 8.2.3.1.**	Medium Inspected in 1997	High; This line is probably the worst with respect to	<10'	Clean up Sludge/ High	Coal Tar/ and Repaired with Epoxy Coating	19' -4	2195 2143 148F444 GE 148F437 sit 5	Central Vault /	In 1997, this line was in inspected and coatings repaired as necessary per the repair activities to NN-3, per BA 323721 and SP-1302-12-268.	Pursue modification to replace this line. See IR 00861654, 00861649, and

Appendix 4 - Inventory of Risk and Consequence Significant Lines - Carbon Steel Pipe											
ID	**Description System**	**Susceptibility**	**Consequence**	**Len.**	**Fluid/ Contamination**	**Coating/ Protection**	**EL/ 1.2.1.**	**Drawings**	**Located**	**Inspections and Repairs**	**Action**
			contamination levels Medium			w/ Nukon Wrap				This Line cannot be Guided Wave Inspected - too small	00861645).
CS-2	NN-2; 6" Fuel Pool cooling to Radwaste (Fuel Pool Filter) A106 Filter Bypass **Section 8.2.4.1**	Medium	Medium	<10'	Reactor Water / Medium	Coal Tar and Repaired Epoxy Coating w/ Nukon Wrap	19' -4	2195 2153 GE 237E756	Central Vault /	**In 1997, this line was in inspected and coatings repaired as necessary per the repair activities to NN-3, per BA 323721 and SP-1302-12-268.** Can only be inspected in 1 Refueling Outage	**To be GW inspected in 2010 (IR 00686711)**
CS-3	ND-11; 6" Cleanup to High Purity Tank -This line is not used any more; However, it is still available for service. A106 **Section 8.2.4.1**	Medium;	Medium	<15'	Reactor Water / Medium	Coal Tar and Repaired Epoxy Coating w/ Nukon Wrap	18' -5'	2195 2143 148F444	Central Vault /	In 1997, this line was in inspected and coatings repaired as necessary per the repair activities to NN-3, per BA 323721 and SP-1302-12-268. Can only be inspected in 1 Refueling Outage	To be GW inspected in 2010 (IR 00686711)
CS-4	ND-11; 6" Cleanup to Condensate System A106 **Section 8.2.4.1**	Medium Inspected	Medium	<15'	Reactor Water / Medium	Coal Tar and Repaired Epoxy Coating w/ Nukon Wrap	18' -5'	2195 2143 148F444	Central Vault /	This line was inspected coating was found degraded – pipe wall was acceptable. Coating was repaired MNCR 93-101 Can only be inspected in 1 Refueling Outage	To be GW inspected in 2010 (IR 00686711)

Appendix 4 - Inventory of Risk and Consequence Significant Lines - Carbon Steel Pipe											
ID	**Description System**	**Susceptibility**	**Consequence**	**Len.**	**Fluid/ Contamination**	**Coating/ Protection**	**EL/ 1.2.1.**	**Drawings**	**Located**	**Inspections and Repairs**	**Action**
CS-5	NV-6; 1 ½"RBEDT line to Radwaste – Ties in with NV-7 in the pipe Tunnel; A53 **Section 8.2.4.1**	Medium Inspected	Medium	<15'	Water / Medium	Coal Tar and Repaired Epoxy Coating w/ Nukon Wrap	18'4" -5'	2195 2184 147434	Partially in central Vault and under the Office building /	This line was in inspected in mid 1990s and coatings repaired as necessary per the repair activities to NN-3, per BA 323721 and SP-1302-12-268 This Line may not be Guided Wave Inspected due to size limitation.	To be GW inspected in 2010 (IR 00686711)
CS-6	NV-4; 2" Laundry Drains to Radwaste A53 **Section 8.2.2.4** Inspected Using Guided wave in 2007	High	Medium Low	<10'	Water / Medium	Coal Tar and Repaired Epoxy Coating w/ Nukon Wrap	12' -11'	2195 2184 148F437	Southeast Vault	Inspected in 1993; coating satisfactory – MNCR 93-143 Inspections of this line in 2001 were found satisfactory. This coating was again inspected in 2004 showing coating degradation requiring repairs (CAP O2004-2071). 2004 UT Inspection of this line showed no wall thinning. Coating degradation is believed to be due to the elevated temperatures this lines experiences. Inspected Using Guided wave in 2007 see reference 10.24 **Inspected in 2008**	PM57304M will inspect this line every 2 years
CS-7	NV-8; 3" RB sump to Radwaste A53	Low	Medium	<10'	Water /	Coal Tar and	12' -11'	2195 2184	Southeast Vault	Inspected in 1993; coating was found degraded; repaired. UT	PM57304M will inspect this line

Appendix 4 - Inventory of Risk and Consequence Significant Lines - Carbon Steel Pipe

ID	Description System	Susceptibility	Consequence	Len.	Fluid/ Contamination	Coating/ Protection	EL/ 1.2.1.	Drawings	Located	Inspections and Repairs	Action
	Section 8.2.2.4. **Visually Inspected in 2008**				Medium	Repaired Epoxy Coating w/ Nukon Wrap		148F437		showed piping wall acceptable – MNCR 93-143 Inspections of this line in 2001 and 2004 showed the coating is in good condition (CAP O2004-2071). **Visually Inspected in 2008**	every two years
CS-8	NV-7; 2" DWEDT to Radwaste Ties into NV-6 in the pipe tunnel. A53 **Section 8.2.2.4.** **Visually Inspected in 2008**	High	Medium	<10'	Water / Medium	Coal Tar	12' -11'	2195 2184 148F437	Southeast Vault	Inspected in 93; coating satisfactory – MNCR 93-143. Inspections of this line in 2001 and 2004 show coating degradation requiring repairs (CAP O2004-2071). UT Inspection of this line showed a slight amount of wall thinning. Coating degradation is believed to be due to the elevated temperatures this lines experiences. **Inspected in 2008** Inspected Using Guided wave in 2007 see reference 10.24	PM57304M will inspect this line every two years
CS-19	AE-1; 30/36" Mechanical Vacuum Pump Offgas Line; A106	High	High	410'	Offgas / medium	Coal Tar and Repaired Epoxy	2'8" – 9'6"	2192 4005 2008 2009	Between the Turbine building and the stack and the AOG.	Can only be inspected in 1 Refueling Outage	To be GW inspected in 2010 (IR 00686711)

Appendix 4 - Inventory of Risk and Consequence Significant Lines - Carbon Steel Pipe											
ID	**Description System**	**Susceptibility**	**Consequence**	**Len.**	**Fluid/ Contamination**	**Coating/ Protection**	**EL/** 1.2.1.	**Drawings**	**Located**	**Inspections and Repairs**	**Action**
	Section 8.2.2.1					Coating w/ Nukon Wrap					
CS-20	AE-1; 48" Offgas Hold up; A106 **Section 8.2.2.1**	High	High	510'	Offgas/ Medium	Coal Tar	2'8" – 9'6"	2192 4005 2009 20008	Between the Turbine building and the stack and the AOG.	Can only be inspected in 1 Refueling Outage	To be GW inspected in 2010 (IR 00686711)
CS-22	4" Off gas to AOG; A106; Line Spec- 0G-100 **Section 8.2.4.3**	Medium	Medium	100'	Offgas	Denso Anti Corrosion Tape	18'	M690 2009	Between The Stack and AOG Building		To be GW inspected in 2010 (IR 00686711)
CS-23	2" Off gas from AOG; A106; Line Spec- 0G-125 **Section 8.2.4.3**	Medium	Medium	100'	Offgas	Denso Anti Corrosion Tape	18'	M690	Between The Stack and AOG Building		To be GW inspected in 2010 (IR 00686711)
CS-24	CH –1; 10-inch from Cond. Tank & Cond. Building to Hotwell; A106 **Section 8.2.4.4** Inspected Using Guided wave in 2007	Medium	Medium	30'	Condensate	Coal Tar	17'	2193	From the Condensate Transfer Building to the west wall of the Turbine Building.	Inspected in 1993. Inspected Using Guided wave in 2007 see reference 10.24	Re inspect in 2012
CS-26	CH –1; 1" from Cond. Building to	Medium	Medium	30'	Condensat	Coal Tar	18'	2193	From the Condensate	This Line cannot be Guided Wave Inspected	Pursue modification to

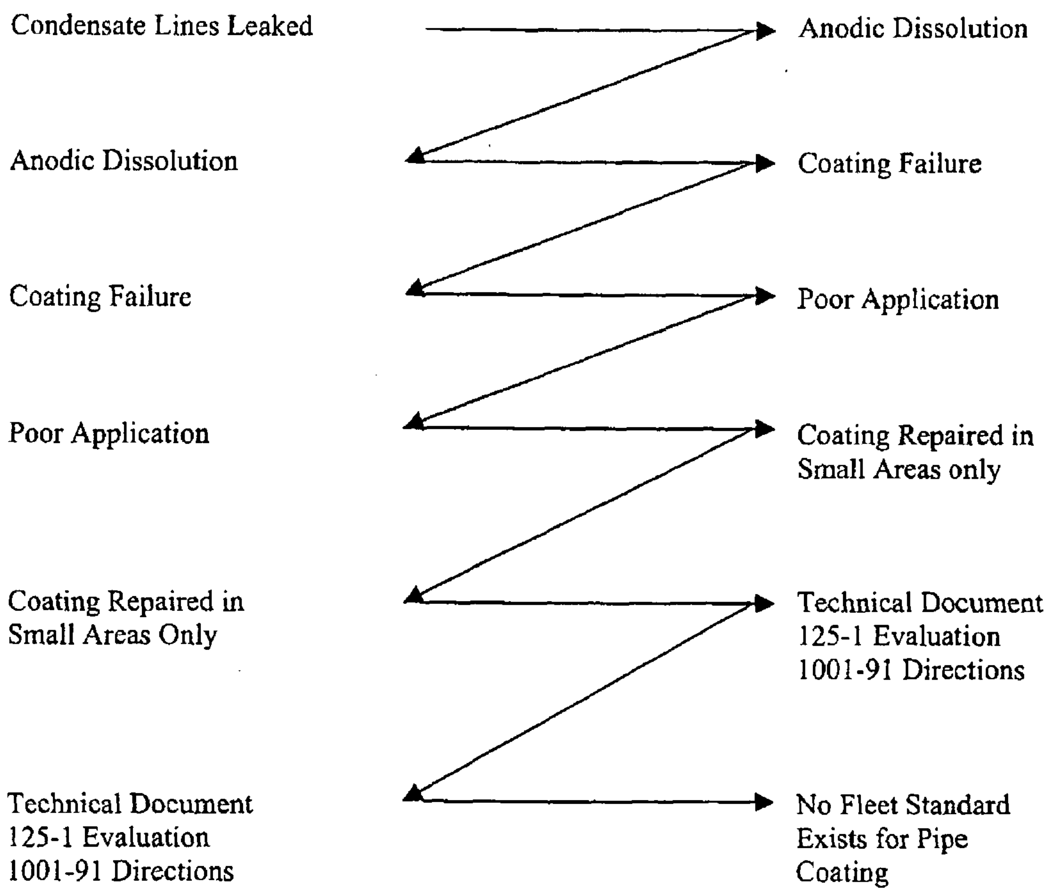
Appendix 4 - Inventory of Risk and Consequence Significant Lines - Carbon Steel Pipe

ID	Description System	Susceptibility	Consequence	Len.	Fluid/ Contamination	Coating/ Protection	EL/ 1.2.1.	Drawings	Located	Inspections and Repairs	Action
	Turbine Building; A106 **Section 8.2.4.5**				e				transfer Building to the west wall of the Turbine Building		replace this line
CS-27	CH -6; 12" overflow line from Cond. Tank & Demin Tank to Turbine Building; A106 Inspected Using Guided wave in 2007	Medium	Low	75'	Air	Coal Tar	16'	2193 2180	From the Condensate transfer tank and Demin tank to the west wall of the Turbine Building	Inspected Using Guided wave in 2007 see reference 10.24	Re inspect in 2012
CS-30	DS-100, 1 ½"; AOG Drains and Sumps: A016 **Section 8.2.4.3**	Medium	Medium	175'	Sump	Denso Anti Corrosion Tape	18'	M690	From AOG to Boiler House		To be GW inspected in 2010 (IR 00686711)
CS-38	1" Condensate Line **Section 8.2.4.5**	Medium	Medium	30	Condensate	External is coal tar	6'	BR 2193	From CST to Turbine Building		Pursue modification to replace this line

Attachment C: Event and Causal Chart

"Tritium 2009 Event and Causal Chart 2.p

Attachment D: Tritium Leak 2009 Why Staircase



Root Cause Evaluation Report

Tritium Identified in Emergency Service Water (ESW) Vault

Condensate Lines Leaked	Thinning of Pipe Not Identified by the Program
Thinning of Pipe Not Identified by the Program	SS-4 Assumed to be Stainless Steel and thought to have a lower susceptibility than Actual
SS-4 Assumed to be Stainless Steel And thought to have a lower Susceptibility than Actual	OC-MM-323643-001 documented mod indicated change to Stainless Steel assumed complete
OC-MM-323643-001 documented Mod indicated change to Stainless Steel assumed complete	Poor Documentation

Condensate Lines Leaked	Thinning of Pipe Not Identified by the Program
Thinning of Pipe Not Identified	Program Basis Document contained Incorrect assumptions
Program Basis Document Contained incorrect assumptions	Lack of independent review of the document
Lack of independent review of the document	Insufficient/ nonexistent program reviews