UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION I
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KING OF PRUSSIA, PA 19406-1415

August 10, 2010

Mr. Thomas P. Joyce
President and Chief Nuclear Officer
PSEG Nuclear LLC - N09
P.O. Box 236
Hancock's Bridge, NJ 08038

SUBJECT: SALEM NUCLEAR GENERATING STATION, UNIT NOS. 1 AND 2 – NRC INTEGRATED INSPECTION REPORT 05000272/2010003 and 05000311/2010003

Dear Mr. Joyce:

On June 30, 2010, the U.S. Nuclear Regulatory Commission (NRC) completed an inspection at the Salem Nuclear Generating Station, Unit Nos. 1 and 2. The enclosed integrated inspection report documents the inspection results discussed on July 8, 2010, with Mr. Fricker and other members of your staff.

The inspection examined activities conducted under your license as they relate to safety and compliance with the Commission's rules and regulations and with the conditions of your license. The inspectors reviewed selected procedures and records, observed activities, and interviewed personnel.

The report documents one NRC-identified finding and one self-revealing finding of very low significance (Green). One of these two findings was determined to involve a violation of NRC requirements. Additionally, one licensee-identified violation of very low safety significance is listed in this report. However, because of the very low safety significance of these two violations and because they were entered into your corrective action program (CAP), the NRC is treating these findings as non-cited violations (NCVs) consistent with Section VI.A.1 of the NRC Enforcement Policy. If you contest any NCV in this report, you should provide a response within 30 days of the date of this inspection report, with the basis for your denial, to the Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington, DC 20555-0001; with copies to the Regional Administrator, Region I; the Director, Office of Enforcement, United States Nuclear Regulatory Commission, Washington, DC 20555-0001; and the NRC Resident Inspector at the Salem Nuclear Generating Station. In addition, if you disagree with the cross-cutting aspect assigned to any finding in this report, you should provide a response within 30 days of the date of this inspection report, with the basis of your disagreement, to the Regional Administrator, Region I, and the NRC Resident Inspector at Salem Nuclear Generating Station.

C/ 184

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Sincerely,

Arthur L. Burritt, Chief
Projects Branch 3
Division of Reactor Projects

Docket Nos: 50-272; 50-311
License Nos: DPR-70; DPR-75

Enclosure: Inspection Report 05000272/2010003 and 05000311/2010003
w/Attachment A: Supplemental Information
Attachment B: TI 172 MSIP Documentation Questions Salem Unit 1

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Sincerely,

/RA/
Arthur L. Burritt, Chief
Projects Branch 3
Division of Reactor Projects

Docket Nos: 50-272; 50-311
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U.S. NUCLEAR REGULATORY COMMISSION

REGION I

Docket Nos:	50-272, 50-311
License Nos:	DPR-70, DPR-75
Report No:	05000272/2010003 and 05000311/2010003
Licensee:	PSEG Nuclear LLC (PSEG)
Facility:	Salem Nuclear Generating Station, Unit Nos. 1 and 2
Location:	P.O. Box 236 Hancocks Bridge, NJ 08038
Dates:	April 1, 2010 through June 30, 2010
Inspectors:	D. Schroeder, Senior Resident Inspector H. Balian, Resident Inspector D. Johnson, Acting Resident Inspector S. Ibarrola, Acting Resident Inspector J. Furia, Senior Health Physicist M. Patel, Reactor Inspector T. O'Hara, Reactor Inspector
Approved By:	Arthur L. Burritt, Chief Projects Branch 3 Division of Reactor Projects

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SUMMARY OF FINDINGS

IR 05000272/2010003, 05000311/2010003; 04/01/2010 - 06/30/2010; Salem Nuclear Generating Station Unit Nos. 1 and 2; Inservice Inspection and Maintenance Effectiveness.

The report covered a three-month period of inspection by resident inspectors, and announced inspections by a regional radiation specialist and reactor engineers. One Green non cited violation (NCV) and one Green finding were identified. The significance of most findings is indicated by their color (Green, White, Yellow, or Red) using Inspection Manual Chapter (IMC) 0609, "Significance Determination Process" (SDP) and the cross-cutting aspect of a finding is determined using IMC 0310, "Components Within the Cross-Cutting Areas." Findings for which the SDP does not apply may be Green or be assigned a severity level after NRC management review. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG-1649, "Reactor Oversight Process," Revision 4, dated December 2006.

Cornerstone: Initiating Events

- Green. A self-revealing finding of very low safety significance was identified on January 21, 2010, because a control system short circuit caused the 21 steam generator feed pump (SGFP) to trip. This caused a turbine runback and ultimately an automatic Unit 2 reactor trip due to low water level in one of four steam generators (SGs). The short circuit occurred because technicians did not use the correct procedure to repair degraded insulation on the barrel of a connector lug that was identified in the 21 SGFP control system in November 2009. PSEG repaired the short circuit prior to restart of Unit 2 on January 23, 2010. The issue was entered into the corrective action program as notification 20448229. PSEGs immediate corrective actions for this issue included repairing the degraded insulation, fixing lug alignment and performing extent of condition inspections on the other Unit 2 SGFP panels for degraded insulation. No other deficiencies were identified.

  This performance deficiency is more than minor because it is associated with the human performance attribute of the Initiating Events cornerstone, and it adversely affected the cornerstone objective to limit the likelihood of events that upset plant stability and challenge critical safety functions. Specifically, not following PSEG procedure SC.DE-TS.ZZ-2039 on November 11, 2009, caused the 21 SGFP trip and subsequent automatic reactor trip due to low SG water level on January 21, 2010. The finding was evaluated under IMC 0609, Attachment 4. The inspectors determined that the finding is of very low safety significance because it does not contribute to both the likelihood of a reactor trip and the likelihood that mitigation equipment or functions will not be available. The inspectors determined that this finding has a cross-cutting aspect in the area of human performance because PSEG personnel did not follow procedure requirements while repairing plant equipment. Specifically, technicians applied electrical tape to the 21 SGFP pressure switch connector lug barrel on November 11, 2009, which did not meet PSEG procedure SC.DE-TS.ZZ-2039 requirements. (H.4 (b)) (Section 1R12)

Cornerstone: Mitigating Systems

- Green. The inspector identified an NCV of very low safety significance for PSEG's failure to perform auxiliary feedwater (AFW) discharge piping system pressure tests on buried piping components as required by 10 CFR 50.55a(g)(4) and the referenced American Society of Mechanical Engineers Code (ASME), Section XI, paragraph IWA-5244 for Salem Unit 1. The required tests are intended to demonstrate the structural integrity of the buried piping portions of the system. PSEG entered this condition into the corrective action program (notification 20459689) and replaced the affected Unit 1 AFW piping.

  This performance deficiency is more than minor, because, if left uncorrected, it would have resulted in a more significant safety concern. Specifically, the inspectors determined that based on the degraded condition of the coating and piping discovered during excavation on Unit 1, without performance of the required pressure test, an undetected failure of the piping would have resulted due to continued, undetected corrosion. The finding impacts the Mitigating Systems cornerstone. Using IMC 0609, Attachment 4, the finding was determined to be of very low safety significance because it was not a design or qualification deficiency, did not result in an actual loss of safety function, and was not potentially risk significant for external events. No cross cutting Aspect is assigned to this violation because this condition began in 1988, more than 3 years ago, and is not indicative of current performance. (Section 1R08)

Other Findings

- One violation of very low safety significance was identified by PSEG and has been reviewed by the inspectors. Corrective actions taken or planned by PSEG have been entered into PSEG's corrective action program (CAP). This violation and its corrective action tracking numbers are listed in Section 4OA7 of this report.

REPORT DETAILS

Summary of Plant Status

Salem Nuclear Generating Station Unit 1 (Unit 1) began the period at full power. On April 2, operators reduced power to 89 percent because heavy river water detritus prevented adequate cooling of the main condenser. On April 3, operators shut down Unit 1 to begin the twentieth refueling outage (RFO) (S1R20). On April 29 the RFO ended when operators synchronized the main generator to the grid. On May 1, operators returned Unit 1 to full power. On June 15, operators reduced power to 3 percent and removed the main turbine from service due to erratic operation of the 13 steam generator (SG) feed regulating valve (FRV). Operators synchronized Unit 1 to the grid again on June 16, but because the 12 SG FRV was not adequately controlling 12 SG water level, operators removed the main turbine from service on June 17. Operators synchronized Unit 1 to the grid on June 17 and returned the unit to full power on June 18. Unit 1 remained at or near full power for the remainder of the inspection period.

Salem Nuclear Generating Station Unit 2 (Unit 2) began the period at full power. On April 1, operators reduced power to 83 percent because heavy river water detritus prevented adequate cooling of the main condenser. On April 2, operators reduced power to 69 percent because heavy river water detritus prevented adequate cooling of the main condenser. On April 5, operators began power ascension and reached full power on April 7. Unit 2 remained at or near full power for the remainder of the inspection period.

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, Barrier Integrity and Emergency Preparedness

1R01 Adverse Weather Protection (71111.01 - 1 sample)

.1 Summer Readiness of Offsite and Alternate AC Power Systems

a. Inspection Scope

The inspectors completed one adverse weather inspection sample to evaluate the readiness of offsite power to the Salem units prior to the summer season when electrical grid stability can be most challenged. The inspectors verified that PSEG provided procedure requirements or guidance to monitor and maintain availability and reliability of the offsite AC Power (OSP) system prior to and during adverse weather conditions. Specifically, the inspectors verified that the procedures addressed:

- The actions to be taken when notified by the electrical system operations center (ESOC) of the PJM interconnection that the post-trip voltage of the OSP system at Salem will not be acceptable to assure the continued operation of the safety-related loads without transferring to the emergency diesel generators (EDGs);
- The compensatory actions to be performed if ESOC cannot predict the post-trip voltage;
- The re-assessment of plant risk for maintenance activities that could affect grid reliability or OSP system availability to the Salem units; and

- Communication requirements between Salem and the ESOC regarding plant changes that could impact the transmission system, or the capacity of the transmission system to provide adequate OSP.

The inspectors also reviewed PSEG's seasonal readiness preparations for the summer season specific to the main power transformers and the OSP system. The inspectors interviewed engineering and work control personnel and reviewed work orders and completed portions of WC-AA-107, Seasonal Readiness, to verify that PSEG took measures to ensure the reliability of the main transformers and the OSP system during the summer season. The documents reviewed during this inspection are listed in the Attachment A.

b. Findings

No findings of significance were identified.

1R04 Equipment Alignment (71111.04 - 3 samples; 71111.04S - 1 sample)

.1 Partial Walk down

a. Inspection Scope

The inspectors completed three partial system walk down inspection samples. The inspectors walked down the systems listed below to verify the operability of redundant or diverse trains and components when safety equipment was inoperable. The inspectors focused their review on potential discrepancies that could impact the function of the system and increase plant risk. The inspectors reviewed applicable operating procedures, walked down control systems components, and verified that selected breakers, valves, and support equipment were in the correct position to support system operation. The inspectors also verified that PSEG properly utilized its corrective action program to identify and resolve equipment alignment problems that could cause initiating events or impact the capability of mitigating systems or barriers. Documents reviewed are listed in the Attachment A.

- Unit 1, 12 service water (SW) header while hardened to support planned unavailability of the 11 SW header;
- Unit 2, 21 component cooling (CC) heat exchanger (HX) with 22 CC HX out-of-service (OOS); and
- Unit 2, 2B and 2C EDG with 2A EDG OOS.

.2 Complete Walk down

a. Inspection Scope

The inspectors conducted one complete walk down inspection sample of the Unit 1 safety injection (SI) system on June 28 through 30, 2010. The inspectors independently verified the alignment and status of SI pump and valve electrical power, labeling, hangers and supports, and associated support systems. The walk down also included evaluation of system piping and equipment to verify pipe hangers were in satisfactory condition, oil reservoir levels were normal, pump rooms and pipe chases were adequately ventilated, system parameters were within established ranges, and equipment deficiencies were appropriately identified. The inspectors interviewed engineering personnel and reviewed corrective action evaluations associated with the system to determine whether equipment alignment problems were identified and appropriately resolved. Documents reviewed are listed in the Attachment A.

b. Findings

No findings of significance were identified.

1R05 Fire Protection (71111.05Q - 6 samples)

.1 Fire Protection - Tours

a. Inspection Scope

The inspectors completed six fire protection quarterly inspection samples. The inspectors walked down the systems listed below to assess the material condition and operational status of fire protection features. The inspectors verified that combustibles and ignition sources were controlled in accordance with PSEG's administrative procedures; fire detection and suppression equipment was available for use; that passive fire barriers were maintained in good material condition; and that compensatory measures for out of service (OOS), degraded, or inoperable fire protection equipment were implemented in accordance with PSEG's fire plan. Documents reviewed are listed in the Attachment A.

- Unit 1, auxiliary building, 84' elevation inside the charging pipe alley;
- Unit 1, electrical penetration, 78' elevation;
- Unit 1, AFW pumps area, 84' elevation;
- Unit 1, diesel fuel oil storage area, 84' elevation;
- Unit 2, diesel fuel oil storage area, 84' elevation; and
- Unit 1, containment during the RFO.

b. Findings

No findings of significance were identified.

1R07 Heat Sink Performance (71111.07A - 1 sample)

a. Inspection Scope

The inspectors completed one annual heat sink performance inspection sample. The inspectors reviewed performance data and interviewed the NRC Generic Letter (GL) 89-13 program manager to verify that potential HX or heat sink deficiencies were identified and PSEG adequately resolved heat sink performance problems. Specifically, the inspectors reviewed 12B component cooling water (CCW) HX data. Inspectors evaluated trending data and verified that equipment would perform satisfactorily under design basis conditions. The method of performance monitoring was compared to the guidance provided in NRC GL 89-13, "Service Water System Problems Affecting Safety-Related Equipment," and Electric Power Research Institute NP 7552, "HX Performance Monitoring Guidelines." Documents reviewed are listed in the Attachment A.

b. Findings

No findings of significance were identified.

1R08 Inservice Inspection (ISI) (71111.08P - 1 sample)

a. Inspection Scope

The inspector observed a selected sample of nondestructive examination (NDE) activities in process. Also, the inspector reviewed the records of selected additional samples of completed NDE and repair/replacement activities. The sample selection was based on the inspection procedure objectives and risk priority of those components and systems where degradation would result in a significant increase in risk of core damage. The observations and documentation reviews were performed to verify that the activities inspected were performed in accordance with the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code requirements.

The inspector reviewed the licensee's performance of a visual inspection (VT) of the Unit 1 reactor vessel closure head (RVCH) and the installed upper head penetrations. The inspector reviewed the visual procedure, the qualifications of the personnel and reviewed the inspection report documenting the inspection results. The inspector also reviewed the data sheets for the penetrant tests completed on three of the penetration welds of the RVCH.

The inspector reviewed records for ultrasonic testing (UT), visual testing (VT), penetrant testing (PT) and magnetic particle testing (MT) NDE processes. PSEG did not perform any radiographic testing (RT) during this outage. The inspector reviewed inspection data sheets and documentation for these activities to verify the effectiveness of the examiner, process, and equipment in identifying degradation of risk significant systems, structures and components and to evaluate the activities for compliance with the requirements of ASME Code, Section XI.

Steam Generator Inspection Activities

The inspectors reviewed a sample of the Unit 1 steam generator eddy current testing (ECT) tube examinations, and applicable procedures for monitoring degradation of steam generator tubes to verify that the steam generator examination activities were performed in accordance with the rules and regulations of the steam generator examination program, Salem Unit 1 steam generator examination guidelines, NRC Generic Letters, 10CFR50, technical specifications for Unit 1, Nuclear Energy Institute 97-06, EPRI PWR steam generator examination guidelines, and the ASME Boiler and Pressure Vessel Code Sections V and XI. The review also included the Salem Unit 1 steam generator degradation assessment and steam generator Cycle 21 and 22 operational assessment. The inspector also verified the individual certifications for personnel participating in the SG ECT inspections during the 1R20 refueling outage. The inspector reviewed PSEG's efforts in identifying wear degradation to the tubing in the four SGs at Unit 1. The majority of the identified wear indications were attributed to anti vibration bar (AVB) wear in the u bend regions of the four SGs. The inspector reviewed the analyses and evaluations that determined that a total of 14 SG tubes would be removed from service by plugging.

Boric Acid Corrosion Control Program Activities

The inspector reviewed the PSEG boric acid corrosion control program. The resident inspectors observed PSEG personnel performing boric acid walkdown inspections, inside containment, and in other affected areas outside of containment, at the beginning of the Unit 1 refueling outage. The inspectors reviewed the notifications generated by the walkdowns and the evaluations conducted by Engineering to disposition the notifications. Additionally, the inspector reviewed a sample of notifications and corrective actions completed to repair the reported conditions.

Section XI Repair/Replacement Samples:

AFW System Piping, Control Air & Station Air: The inspectors reviewed PSEG's discovery, reporting, evaluation and the repair/replacement of Unit 1 AFW piping that was excavated for inspection during the April 2010 Unit 1 refueling outage (1R20). PSEG conducted this inspection in accordance with PSEG's Buried Piping Inspection Program. Additionally, the inspectors reviewed the UT testing results performed to characterize the condition of the degraded Unit 1 buried AFW piping.

The inspector also reviewed the repair/replacement work orders and the 50.59 screening and evaluation for the AFW, CA and SA piping. The inspectors reviewed the fabrication of the replacement piping, reviewed the documentation of the welding and NDE of the replacement piping and reviewed the pressure tests used to certify the replacement piping. Additionally, the inspector reviewed the specified replacement coating, the application of the replacement coating and the backfill of the excavated area after the piping had been tested.

The inspector reviewed the finite element analysis (FEA) results from PSEG's past operability analysis on the affected Unit 1 buried AFW piping completed by the licensee in order to demonstrate past operability at a reduced system pressure of 1275 psig. The design pressure of the AFW system is 1950 psig.

The inspector also reviewed the UT testing results (approximately 400) performed on portions of the Unit 2 AFW buried piping, in response to the conditions observed on Unit 1 AFW buried piping to determine if degradation existed on the Unit 2 buried AFW piping.

Rejectable Indication Accepted For Service After Analysis:

The inspector reviewed the Notification and the UT data report of a rejectable wall thickness measurement on the #11 SG feedwater elbow during 1R20. The inspector reviewed the additional wall thickness data taken to further define the condition and reviewed the finite element analysis (FEA) which verified that sufficient wall thickness remained to operate the component until the next refueling outage when it will be replaced.

b. Finding

Introduction. The inspector identified a Green non-cited violation (NCV) of 10 CFR 50.55a(g)(4) and the referenced American Society of Mechanical Engineers (ASME) Code, Section XI, paragraph IWA-5244 for PSEG's failure to perform required pressure tests of buried AFW components for Salem Unit 1.

Description. Portions of the Unit 1 and Unit 2 AFW system piping is buried piping and has not been visually inspected since the plant began operation in 1977 for Unit 1 and since 1979 for Salem Unit 2. This piping is safety related, 4.0" ID, ASME Class 3, Seismic Class 1 piping. In April 2010, approximately 680 ft. (340 ft. of the #12 SG AFW supply and 340 ft. of the #14 SG AFW supply) of piping between the pump discharge manifold and the connection to the main feedwater piping to the affected SGs was discovered to be corroded to below minimum wall thickness (0.278") for the 1950 psi design pressure of the AFW System. The discovery was noted by PSEG during a planned excavation implementing their buried pipe inspection program. The lowest wall thickness measured in the affected piping was 0.077". The affected Unit 1 piping was replaced. Although no leakage was evident as a result of the corrosion, the inspector questioned PSEG about whether the IWA-5244 periodic pressure tests had been conducted on this underground piping.

10 CFR 50.55(a)(g)(4)(ii) requires licensees to follow the in-service requirements of the ASME Code, Section XI. Paragraph IWA-5244 of Section XI requires licensees to perform system pressure tests on buried components to demonstrate the structural integrity of the tested piping. The system pressure test required by IWA-5244 is considered to be an inservice inspection and is part of Section XI. Section XI and IWA-5244 do not specify other non-destructive examinations (NDE) on buried components to demonstrate structural integrity other than a flow test if the system pressure test cannot be performed. PSEG had not performed the required tests for Unit 1 since 1988. Thus, PSEG did not perform the inservice inspection provided by the ASME Code, Section XI, intended to demonstrate the structural integrity of this safety related buried piping.

PSEG was aware of the need to perform these required tests because they sought relief, from the NRC, from the previous Code required pressure testing in 1988 for Unit 1 only. Relief was granted to PSEG, by the NRC, to perform an alternate flow test in 1991 for Unit 1. However, PSEG did not perform the proposed alternate flow tests for Unit 1 since 1988. Thus, PSEG had a chance to foresee and correct this performance deficiency, but missed the opportunity at the time of processing the final results of the relief request. PSEG replaced the affected Unit 1 buried piping during the refueling outage in April/May 2010. The required pressure tests were successfully completed after the replacement of the Unit 1 buried piping. PSEG determined that the buried portions of AFW maintained structural integrity because the AFW system functioned as required during the plant shutdown prior to the start of 1R20 (April 2010) and based upon the results of a finite element analysis PSEG conducted using as-found UT readings of excavated portions of the Unit 1 piping.

As part of the extent of condition for the testing issue identified on Unit 1, PSEG reviewed the status of ISI testing for Unit 2 AFW and determined that the testing had not been performed since 2001. PSEG currently plans to excavate the Unit 2 buried piping for inspection during the Unit 2 refueling outage scheduled for the spring of 2011. PSEG also completed an operability determination and risk assessment to justify continued operation until the next refueling outage. These evaluations determined that the condition was acceptable for continued operation until spring 2011. At present, it was not feasible to conduct the system pressure test or alternate flow test while at power, and to date there has been no detected degradation of the coating or piping on the Unit 2 buried AFW piping.

Analysis. Visual inspections and UT measurements completed by PSEG on Unit 1 AFW buried piping in April 2010 identified degraded pipe coating and wall thinning on a portion of the excavated pipe. Considering the effect of this identified degradation, not performing the ASME Code, Section XI, paragraph IWA-5244 required pressure test at the required frequency for this normally inaccessible buried piping would result in an undetected loss of structural integrity for buried Unit 1 AFW discharge piping. The inspectors determined this was a performance deficiency.

This performance deficiency was more than minor because, if left uncorrected, it would have resulted in a more significant condition. Specifically, in light of the as-found degraded conditions of the coating and the piping discovered during excavation in Unit 1, an undetected failure of the piping would have resulted due to further continued, undetected corrosion, and continued pipe wall degradation eventually resulting in the loss of structural integrity and inoperability of the Unit 1 AFW system.

The inspector screened this performance deficiency using IMC 0609, Attachment 0609.04, "Phase 1 Initial Screening and Characterization of Findings." This finding impacts the Mitigating Systems cornerstone by adversely affecting the secondary, short term decay heat removal capability. Because the finding was not a design or qualification deficiency, did not result in an actual loss of safety function, and was not potentially risk significant for external events, the inspector determined that the finding screened to Green, very low safety significance for Unit 1.

The inspector determined that a cross cutting aspect did not exist because the issue was not indicative of current performance because the condition existed since 1991, more than 3 years ago. Specifically, the failure to perform these pressure tests began in 1988 when PSEG requested relief from the requirement and did not incorporate the actions of the relief into the plant inservice inspection program when it was granted in 1991.

Enforcement. 10 CFR 50.55a(g)(4) states, in part: "Throughout the service life of a boiling or pressurized water-cooled nuclear power facility, components which are classified as ASME Code Class 1, Class 2 and Class 3 must meet the requirements, set forth in Section XI of editions of the ASME Boiler and Pressure Vessel Code". Paragraph IWA-5244, Buried Components, of Section XI says, in part:

"(b) For buried components where a VT-2 visual examination cannot be performed , the examination requirement is satisfied by the following: (1) The system pressure test for buried components that are isolable by means of valves shall consist of a test that determines the rate of pressure loss. Alternatively, the test may determine the change in flow between the ends of the buried components. "

Contrary to these requirements, PSEG did not perform the required pressure tests of the buried AFW piping to the #12 SG and #14 SG at Salem Unit 1. Specifically, from February 1988 to April 2010 the required pressure tests were not performed to demonstrate structural integrity on the affected buried Unit 1 AFW piping during the 2nd In Service Inspection Interval (2/27/88 to 5/19/01) and during the 1st (5/19/01 to 6/3/04) and 2nd (6/24/04 to 5/20/08) periods of the 3rd In Service Inspection Interval (5/19/01 to 5/19/11).

Because PSEG entered this condition for Salem Unit 1 into the corrective action process (Notification 20459686) and because it is of very low safety significance (Green), it is being treated as a non-cited violation consistent with Section VI.A.1 of the NRC Enforcement Policy. **NCV 50-272/2010003-01, Buried AFW Discharge Piping Not Tested In Accordance With 10 CFR 50.55a.**

1R11 Licensed Operator Requalification Program (71111.11Q - 1 sample)

.1 Requalification Activities Review by Resident Staff

a. Inspection Scope

The inspectors completed one quarterly licensed operator requalification program inspection sample. Specifically, the inspectors observed a scenario administered to a single crew during an emergency preparedness drill on May 18, 2010. The scenario included a crane damaging the AFW storage tank, a small reactor coolant leak, a rod ejection that resulted in a small break loss-of-coolant accident, and a rupture to containment spray piping that resulted in a loss of containment integrity.
The inspectors reviewed operator implementation of the abnormal and emergency operating procedures. The inspectors examined the operators' ability to perform actions associated with high risk activities, the Emergency Plan, previous lessons learned items, and the correct use and implementation of procedures. The inspectors observed and

verified that deficiencies were adequately identified, discussed, and entered into the CAP, as appropriate. Documents reviewed are listed in the Attachment A.

b. Findings

No findings of significance were identified.

1R12 Maintenance Effectiveness (71111.12Q - 3 samples)

a. Inspection Scope

The inspectors completed three quarterly maintenance effectiveness inspection samples. The inspectors reviewed performance monitoring and maintenance effectiveness issues for the three systems listed below. The inspectors reviewed PSEG's process for monitoring equipment performance and assessing preventive maintenance effectiveness. The inspectors verified that systems and components were monitored in accordance with the Maintenance Rule Program requirements. The inspectors compared documented functional failure determinations and unavailability hours to those being tracked by PSEG to evaluate the effectiveness of PSEG's condition monitoring activities and to determine whether performance goals were being met. The inspectors reviewed applicable work orders, corrective action notifications, and preventive maintenance tasks. The documents reviewed are listed in the Attachment A.

- Unit 1 and Unit 2, radiation monitors;
- Unit 2, steam generator feed pumps; and
- Unit 1, service water.

b. Findings

Introduction: A self-revealing finding of very low safety significance was identified on January 21, 2010, because a control system short circuit caused the 21 SGFP to trip. This caused a turbine runback and ultimately an automatic Unit 2 reactor trip due to low water level in one of four SGs. The short circuit occurred because technicians did not use the correct procedure to repair degraded insulation on the barrel of a connector lug that was identified in the 21 SGFP control system in November 2009. PSEG repaired the short circuit prior to restart of Unit 2 on January 23, 2010. The issue was entered into the corrective action program as notification 20448229.

Description: On January 21, 2010, the 21 SGFP tripped due to a short circuit between the normally closed and normally open terminals for the 21 SGFP low suction pressure trip switch. The short circuit caused a false low suction pressure trip signal that tripped the 21 SGFP, which caused a turbine runback to 66%. This runback was designed to lower the steam flow demanded from the SGs to within the capacity of the SGFP that did not trip. However, on January 21, the reduction in power was not rapid enough and Salem Unit 2 automatically tripped from 78% power due to low steam generator water level.

Following the trip technicians identified that the electrical short that caused the trip had developed between a connector lug barrel and an adjacent wire terminal due degraded wire insulation on the lug barrel. The technicians also determined that this same short was previously identified as the cause of the difficulty that operators had resetting the 21 SGFP on November 11, 2009, during the Unit 2 startup after the S2R17 refueling outage. To address the condition identified in November 2009, the technicians covered the affected connector lug barrel with electrical tape. This allowed operators to restore the 21 SGFP to service and continue the Unit 2 start-up. The reset problems for the 21 SGFP repeated again on January 5, 2010, during the Unit 2 plant startup after the January 3, 2010 plant trip. However, troubleshooting in early January did not identify a cause for the trip and the 21 SGFP was ultimately successfully reset and restored to service with no corrective actions completed.

PSEG conducted a root cause investigation after the January 21, 2010, trip and determined the root cause was poor work practices during initial component installation and subsequent maintenance activities. Specifically, improper orientation of the lug put the lug barrel and wire terminal in contact with one another, which subsequently caused the lug barrel insulation to degrade ultimately resulting in the short circuit.

The inspectors determined that the corrective actions taken by technicians when they originally identified the short between the lug barrel and wire terminal in November 2009, were not adequate. As stated above, to correct the short, technicians covered the affected insulation with electrical tape. The inspectors reviewed PSEG procedure SC.DE-TS.ZZ-2039, "Cable Termination Methods at Salem Generating Station," and determined that applying tape to the barrels of lugs was not permitted. Therefore, the corrective actions taken by technicians to address the degraded condition identified in November 2009, did not meet PSEG procedure requirements and resulted in the 21 SGFP trip that cause the Unit 2 reactor trip on January 21, 2010.

PSEGs corrective actions following the January 21, 2010 included performing extent of condition inspections on the other Unit 2 SGFP panels for degraded insulation no other deficiencies were identified. Following completion of the root cause analysis additional extent of condition inspections for connector lug orientation were specified. Unit 1 inspections were completed in April 2010 and no deficiencies were identified. Unit 2 inspections are scheduled for the next refueling outage in 2011. PSEG entered corrective action issues for this event into the corrective action program as NOTF 20448229.

To improve the reliability of the plant operations in response to a single SGFP trip, PSEG installed an automatic plant runback feature in the 1990s. The inspectors confirmed that this feature was not credited in the plant's accident analysis, and therefore, determined that the failure of the runback to prevent a reactor trip after the 21 SGFP tripped on January 21 was not a safety concern. PSEG's plans to review the causes of the ineffective runback as part of the response to correction action program NOTF 20448229.

Analysis: Not performing repairs to the affected 21 SGFP pressure switch lug barrel in accordance with PSEG SC.DE-TS.ZZ-2039, "Cable Termination Methods at Salem Generating Station," resulted in a short circuit that caused a 21 SGFP trip that resulted in a Unit 2 reactor trip due to low SG water level. This was a performance deficiency. The inspectors determined that the performance deficiency was more than minor because it was associated with the human performance attribute of the Initiating Events cornerstone, and it adversely affected the cornerstone objective to limit the likelihood of events that upset plant stability and challenge critical safety functions. Specifically, not following PSEG procedure SC.DE-TS.ZZ-2039 on November 11, 2009, caused the 21 SGFP trip and subsequent automatic reactor trip due to low SG water level on January 21, 2010. The finding was evaluated under IMC 0609, Attachment 4, "Phase 1 – Initial Screening and Characterization of Findings." The inspectors determined that the finding is of very low safety significance because it does not contribute to both the likelihood of a reactor trip and the likelihood that mitigation equipment or functions will not be available.

The inspectors determined that this finding has a cross-cutting aspect in the area of human performance because PSEG personnel did not follow procedure requirements while repairing plant equipment. Specifically, technicians applied electrical tape to the 21 SGFP pressure switch connector lug barrel on November 11, 2009, which did not meet PSEG procedure SC.DE-TS.ZZ-2039, "Cable Termination Methods at Salem Generating Station," requirements. (H.4 (b))

Enforcement: Enforcement action does not apply because the performance deficiency did not involve a violation of a regulatory requirement: **FIN 05000311/2010003-02, 21 Steam Generator Feed Pump Trip.**

1R13 Maintenance Risk Assessments and Emergent Work Control (71111.13 - 5 samples)

a. Inspection Scope

The inspectors completed five maintenance risk assessment and emergent work control inspection samples. The inspectors reviewed the maintenance activities listed below to verify that the appropriate risk assessments were performed as specified by 10 CFR 50.65(a)(4) prior to removing equipment for work. The inspectors reviewed the applicable risk evaluations, work schedules, and control room logs for these configurations. PSEG's risk management actions were reviewed during shift turnover meetings, control room tours, and plant walkdowns. The inspectors also used PSEG's on-line risk monitor (Equipment OOS workstation) to gain insights into the risk associated with these plant configurations. The inspectors reviewed notifications documenting problems associated with risk assessments and emergent work evaluations. Documents reviewed are listed in the Attachment A.

- Unit 1 and Unit 2, planned unavailability of Unit 1 control room emergency air conditioning system to support planned maintenance on the 1A 125 VDC electrical bus on April 7;
- Unit 1, planned unavailability of the 1A EDG and 14 station power transformer during a RFO on April 8;
- Unit 1, contingency measures to provide alternate power to the 12 spent fuel pool (SFP) pump during unavailability of the 1B 4kV vital bus on April 12;
- Unit 1, unplanned unavailability of the 1C 4kV vital bus concurrent with planned unavailability of the 1B EDG and 11 SW header on April 16;
- Unit 2, planned unavailability of the 2A EDG with station blackout Unit 3 out of service on May 27.

b. Findings

No findings of significance were identified.

1R15 Operability Evaluations (71111.15 - 8 samples)

a. Inspection Scope

The inspectors completed eight operability evaluation inspection samples. The inspectors reviewed the operability determinations for degraded or non-conforming conditions associated with:

- Unit 1 and Unit 2 EDGs given potential degradation of shutdown relays SDR, SR and SRA;
- Unit 1 boration flowpath following unplanned unavailability of the 1C 4kV vital bus while in Mode 6;
- Unit 1 SW system given early installation of restraints on pipe support SWPS-5;
- Unit 1 CCW system during planned unavailability of the 11 CCW HX and biofouling of the 12A/B CCW HX;
- Unit 1 AFW piping following discovery of wall thinning of buried piping;
- Unit 2 AFW piping following the discovery of wall thinning of Unit 1 AFW piping;
- 22 SW 122 air operated valve (AOV) following the failure of the 21 SW 122 AOV; and
- 11 SW 122 AOV following the failure of the 21 SW 122 AOV.

The inspectors reviewed the technical adequacy of the operability determinations to ensure the conclusions were justified. The inspectors also walked down accessible equipment to corroborate the adequacy of PSEG's operability determinations. Additionally, the inspectors reviewed other PSEG identified safety-related equipment deficiencies during this report period and assessed the adequacy of their operability screenings. Documents reviewed are listed in the Attachment A.

b. Findings

No findings of significance were identified.

1R18 Plant Modifications (71111.18 - 4 samples)

.1 Permanent Modifications

a. Inspection Scope

The inspectors completed two permanent plant modification inspection samples by reviewing the key characteristics associated with the two permanent plant modifications described below. The inspectors' review verified that the design bases, licensing bases, and performance capability of the affected systems were not degraded by the modifications. The inspectors verified the new configuration was accurately reflected in the design documentation and that the post-modification testing was adequate to ensure the structures, systems, and components affected would continue to function properly.

The inspectors' also interviewed plant staff and reviewed issues that were entered into the CAP to assess whether PSEG was effective at identifying and resolving problems associated with the modification process. The 10 CFR 50.59 screening associated with these permanent plant modifications were also reviewed. The documents reviewed are listed in the Attachment A.

- The inspectors reviewed the modification package used to replace the section of buried Unit 1 AFW discharge header piping located between the Unit 1 auxiliary and containment buildings. PSEG replaced this section of piping because significant coating degradation and external corrosion and wall thinning was identified on the piping during inspections conducted in preparation for license renewal.
- The inspectors reviewed the modification package used to replace the Unit 1 PS-1 pressurizer spray valve internals. The purpose of the new design was to provide better flow control characteristics and reduce the valve's susceptibility to sticking.

b. Findings

No findings of significance were identified.

.2 Temporary Modifications

a. Inspection Scope

The inspectors completed two plant modification inspection samples by reviewing the key characteristics associated with the two temporary plant modifications described below. The inspectors verified that the design bases, licensing bases, and performance capability of the affected systems were not degraded by the temporary modifications. The 10 CFR 50.59 screen associated with each modification were also reviewed. Documents reviewed for this inspection are listed in the Attachment A.

- The inspectors reviewed the modification package used to supply temporary power to the 12 SFP pump. The modification moved the 12 SFP pump power supply from the 1B 460 VAC vital bus to the 1A 460 VAC vital bus to provide SFP cooling capacity from both the 11 and 12 SFP pumps while the 1B 460 VAC vital bus was de-energized for planned maintenance.
- The inspectors reviewed the modification package used to plug a Unit 1 feedwater flow control valve (13BF19) air supply regulator weep hole in order to ensure that full pressure was used to position the air-operated valve.

b. Findings

No findings of significance were identified.

1R19 Post-Maintenance Testing (71111.19 - 6 samples)

a. Inspection Scope

The inspectors completed six post-maintenance testing (PMT) inspection samples. The inspectors observed portions of and/or reviewed the PMT results for the maintenance activities listed below. The inspectors verified that the effect of testing on the plant was adequately addressed by control room and engineering personnel; testing was adequate for the maintenance performed; acceptance criteria were clear, demonstrated operational readiness and were consistent with design and licensing basis documentation; test instrumentation calibration was current and the appropriate range and accuracy for the application; tests were performed, as written, with applicable prerequisites satisfied; and equipment was returned to an operational status and ready to perform its safety function. Documents reviewed are listed in the Attachment A.

- Work order (WO) 30156599, preventive maintenance of the 1A vital instrument bus inverter;
- WO 30171818, planned overhaul of the 1B EDG during Unit 1 RFO;
- WO 60090348, replacement of shaft and pins on 21 CCW HX inlet valve, 21 SW 122;
- WO 60090391, replacement of shaft and pins on 22 CCW HX inlet valve, 22 SW 122;
- WO 30152753, preventive maintenance of the 22 AFW pump; and
- WO 60088790, temporary repair of an oil leak on 21 SI pump outboard bearing.

b. Findings

No findings of significance were identified.

1R20 Refueling and Other Outage Activities (71111.20 - 1 sample)

a. Inspection Scope

Unit 1 RFO (S1R20). The inspectors completed one refueling outage activity inspection sample. The inspectors observed or reviewed the following RFO activities to verify that operability requirements were met and that risk, industry experience, the fatigue rule, and previous site specific problems were considered. Documents reviewed are listed in the Attachment A.

The inspectors reviewed the schedule and risk assessment documents associated with S1R20 to confirm that PSEG appropriately considered risk, operating experience, and site specific problems in developing and implementing a plan that ensured maintenance of defense-in-depth systems and barriers. Prior to S1R20, the inspectors reviewed PSEG's outage risk assessment to identify risk significant equipment configurations and determine whether planned risk management actions were adequate. During S1R20, the inspectors verified that PSEG managed the outage risk in accordance with the outage plan.

The inspectors observed portions of the shutdown and cool down processes and monitored PSEG controls over the outage activities. The inspectors also verified that cool down rates were within technical specification (TS) limitations. The inspectors entered containment at the start of the refuel outage to check for evidence of previously unidentified reactor coolant leakage. Throughout S1R20, the inspectors made additional containment entries to inspect for indications of unidentified leakage, damaged equipment, foreign material control, radiation worker work practices and fire prevention.

The inspectors observed portions of refueling activities from the refueling bridge in containment and the SFP to verify refueling gates and seals were properly installed and verify that foreign material exclusion boundaries were established around the reactor cavity. Core offload and core reload activities were periodically observed from the control room and refueling bridge to verify operators adequately controlled fuel movements in accordance with approved procedures.

The inspectors verified that tagged equipment was properly controlled and equipment configured to safely support maintenance work. Specifically, inspectors observed the control of work activities in the auxiliary building during reduced inventory to verify that the risk of unplanned equipment unavailability was minimized. Equipment work areas were periodically observed to determine whether foreign material exclusion boundaries were adequate.

During control room tours, the inspectors verified that operators maintained adequate reactor coolant system (RCS) level and temperature and that indications were within the expected range for the operating mode.

The inspectors verified that offsite and onsite electrical power sources were maintained in accordance with TS requirements and consistent with the outage risk assessment. Periodic walk downs of portions of the on-site electrical buses and the EDGs were conducted during risk significant electrical configurations.

The inspectors verified through routine plant status activities that the decay heat removal safety function was maintained with the appropriate redundancy as required by TS and consistent with PSEG's outage risk assessment. During core offload, the inspectors periodically verified that the fuel pool cooling system was performing in accordance with plant design parameters and consistent with PSEG's risk assessment for the RFO.

The inspectors observed the Unit 1 RCS draining to a reduced inventory condition on April 19, 2010. RCS inventory controls and contingency plans were reviewed by inspectors to verify that they met TS requirements and provided for adequate inventory control. The inspectors reviewed procedures and observed portions of activities in the control room when the unit was in reduced inventory modes of operation. The inspectors verified that level and core temperature measurement instrumentation were installed and operational. Calculations that provided time to boil information were also reviewed for RCS reduced inventory conditions as well as the SFP during increased heat load conditions.

Inspectors verified that PSEG managed fatigue of outage workers by reviewing a sampling of waiver requests, self declarations, and fatigue assessments that were available near the end of the RFO. PSEG scheduled covered workers such that minimum days off for individuals working on outage activities were in compliance with the fatigue rule. In addition, control room staff for Unit 2 remained on operating unit work hour controls.

Containment status and procedural controls were reviewed by the inspectors during fuel offload and reload activities to verify that TS and procedure requirements were met for containment. Specifically, the inspectors verified that during fuel movement activities, personnel, materials, and equipment were staged to close containment penetrations as specified in the licensing basis.

The inspectors conducted a thorough walk down of containment prior to reactor startup. Areas of containment where work was completed were inspected for evidence of leakage and to ensure debris that could block containment sump screens was removed. The condition of equipment used for fire detection, prevention, and suppression were inspected for operability and functionality. Portions of mode changes and reactor startup were observed and reviewed for compliance with applicable procedures and TS.

b. Findings

No findings of significance were identified.

1R22 Surveillance Testing (71111.22 - 9 samples)

a. Inspection Scope

The inspectors completed nine surveillance testing inspection samples. The inspectors observed portions of and/or reviewed results for the surveillance tests listed below to verify, as appropriate, whether the applicable system requirements for operability were adequately incorporated into the procedures and that test acceptance criteria were consistent with procedure requirements, the TS requirements, the updated final safety analysis report (UFSAR), and American Society of Mechanical Engineers (ASME) Section XI for pump and valve testing. Documents reviewed are listed in the Attachment A.

- S1.OP-ST.RHR-0005, Residual Heat Removal Valves and Orifices;
- S1.OP-ST.MS-0003, Steam Line Isolation and Response Time Testing;
- S1.OP-ST.TRB-0002, Turbine Protection System – Full Functional Test;
- S1.OP-ST.SJ-0015, Intermediate Head Hot Leg Throttling Valve Flow Balance Verification;
- SC.MD-DC.RC-0003, Calibration of Pressurizer Safety Relief Valve Indicating Switches;
- S1.OP-ST.AF-0007, 13 AFW Pump Full Flow Test;
- S2.OP-ST.SJ-0001, Inservice Testing of 21 Safety Injection Pump;
- S1.OP-LR.FP-0001, Type C Leak Rate Test for 1FP147 and 1FP148; and
- S1.OP-LR.CVC-0003, Type C Leak Rate Test for 1CV116, 1CV284, and 1CV296.

b. Findings

No findings of significance were identified.

1EP6 Drill Evaluation (71114.06 - 1 sample)

a. Inspection Scope

The inspectors completed one drill evaluation inspection sample. On May 18, 2010, the inspectors observed a drill from the control room simulator during an evaluated emergency preparedness drill. The inspectors evaluated operator performance relative to developing event classifications and notifications. The inspectors referenced Nuclear Energy Institute (NEI) 99-02, "Regulatory Assessment Performance Indicator (PI) Guideline," Revision 6, and verified that PSEG correctly counted the evaluated scenario's contribution to the NRC PI for drill and exercise performance.

b. Findings

No findings of significance were identified.

2. RADIATION SAFETY

Cornerstone: Radiation Safety - Public and Occupational

2RS1 Radiological Hazard Assessment and Exposure Controls (71124.01)

a. Inspection Scope

Radiological Hazard Assessment

The inspectors reviewed any changes to plant operations that may result in a significant new radiological hazard for onsite workers or members of the public. The inspectors verified PSEG had assessed the potential impact of these changes and implemented periodic monitoring, as appropriate, to detect and quantify the radiological hazard.

The inspectors reviewed a sample of two completed radiological surveys of selected plant areas. The inspectors verified that the thoroughness and frequency of the surveys were appropriate for the given radiological hazard.

The inspectors conducted walk downs of the plant that included radioactive waste processing, storage, and handling areas to evaluate material conditions and potential radiological conditions.

The inspectors selected radiological risk-significant work activities that involved exposure to radiation and were performed during Unit 1's RFO. Activities selected included: primary steam generator work including eddy current testing, secondary steam generator work including foreign object search and retrieval, and replacement of the #14 reactor coolant pump motor. The inspectors verified that appropriate pre-work surveys were performed and were appropriate to identify and quantify the radiological hazard and to establish adequate protective measures. The inspectors evaluated the radiological survey program to determine if the following hazards were properly identified:

- Identification of hot particles;
- The presence of alpha emitters;
- The potential for airborne radioactive materials, including the potential presence of transuranics and/or other hard-to-detect radioactive materials;
- The hazards associated with work activities that could suddenly and severely increase radiological conditions; and

- Severe radiation field dose gradients that can result in non-uniform exposures to the body.

The inspectors selected three to five air sample survey records and verified that samples were collected and counted in accordance with PSEG procedures. The inspectors observed work in potential airborne areas and verified that air samples were representative of the breathing air zone. The inspectors verified that PSEG has a program for monitoring levels of loose surface contamination in areas of the plant with the potential for the contamination to become airborne.

Radiological Hazards Control and Work Coverage

During tours of the facility and review of ongoing work selected in Section 2 (above), the inspectors evaluated ambient radiological conditions. The inspectors verified that existing conditions were consistent with posted surveys, radiation work permits (RWPs), and worker briefings, as applicable.

During job performance observations, the inspectors verified the adequacy of radiological controls, such as required surveys, radiation protection job coverage, and contamination controls. The inspectors evaluated PSEG's means of using electronic pocket dosimeters in high noise areas as high radiation area (HRA) monitoring devices.

The inspectors verified that radiation monitoring devices were placed on the individual's body consistent with the method that PSEG has employed to monitor dose from external radiation sources. The inspectors verified that the dosimeter was placed in the location of highest expected dose or that PSEG was properly employing an NRC-approved method of determining effective dose equivalent.

For high-radiation work areas with significant dose rate gradients (a factor of 5 or more), the inspectors reviewed the application of dosimetry to effectively monitor exposure to personnel. The inspectors verified that PSEG's controls were adequate.

The inspectors reviewed three to five RWPs for work within airborne radioactivity areas with the potential for individual worker internal exposures. The inspectors evaluated airborne radioactive controls and monitoring, including potentials for significant airborne contamination. For these selected airborne radioactive material areas, the inspectors verified barrier integrity and temporary high-efficiency particulate air ventilation system operation.

The inspectors examined PSEG's physical and programmatic controls for highly activated or contaminated materials stored within spent fuel and other storage pools. The inspectors verified that appropriate controls were in place to preclude inadvertent removal of these materials from the pool.

The inspectors conducted selective inspection of posting and physical controls for HRAs and very high radiation areas, to the extent necessary to verify conformance with the Occupational PI.

b. Findings

No findings of significance were identified.

2RS2 Occupational As Low As Reasonably Achievable (ALARA) Planning and Controls (71124.02)

a. Inspection Scope

Radiological Work Planning

The inspectors obtained from PSEG a list of work activities ranked by actual or estimated exposure that were in progress and selected three work activities of the highest exposure significance (listed in Section 2RS1 above).

The inspectors reviewed the ALARA work activity evaluations, exposure estimates, and exposure mitigation requirements. The inspectors determined that PSEG had reasonably grouped the radiological work into work activities, based on historical precedence, industry norms, and/or special circumstances.

The inspectors verified that PSEG's planning identified appropriate dose mitigation features, considered alternate mitigation features, and defined reasonable dose goals. The inspectors verified that PSEG's ALARA assessment had taken into account decreased worker efficiency from use of respiratory protective devices and or heat stress mitigation equipment. The inspectors determined that PSEG's work planning considered the use of remote technologies as a means to reduce dose and the use of dose reduction insights from industry operating experience and plant-specific lessons learned. The inspectors verified the integration of ALARA requirements into work procedure and RWP documents.

The inspectors compared the results achieved with the intended dose established in PSEG's ALARA planning for these work activities. The inspectors compared the person-hour estimates provided by maintenance planning and other groups to the radiation protection group with the actual work activity time requirements, and evaluated the accuracy of these time estimates. The inspectors determined the reasons for any inconsistencies between intended and actual work activity doses. The inspectors focused on those work activities with planned or accrued exposure greater than 5 person-rem.

The inspectors determined that post-job reviews were performed and that identified problems were entered into PSEG's CAP.

b. Findings

No findings of significance were identified.

4. OTHER ACTIVITIES

4OA1 Performance Indicator (PI) Verification (71151 - 6 samples)

a. Inspection Scope

The inspectors reviewed PSEG submittals for the Unit 1 and Unit 2 initiating events cornerstone performance indicators discussed below. To verify the accuracy of the PI data reported during this period the data was compared to the PI definition and guidance contained in NEI 99-02, "Regulatory Assessment Performance Indicator Guideline," Revision 5.

Cornerstone: Initiating Events

- Unit 1 and Unit 2 unplanned scrams;
- Unit 1 and Unit 2 unplanned scrams with complications; and
- Unit 1 and Unit 2 unplanned power changes.

The inspectors verified the accuracy of the data by comparing it to CAP records, control room operators' logs, the site operating history database, and key performance indicator summary records.

b. Findings

No findings of significance were identified.

4OA2 Identification and Resolution of Problems (71152 - 1 annual sample; 1 trend sample)

.1 Review of Items Entered into the Corrective Action Program

As required by Inspection Procedure 71152, "Identification and Resolution of Problems," and in order to help identify repetitive equipment failures or specific human performance issues for follow-up, the inspectors performed a daily screening of all items entered into PSEG's CAP. This was accomplished by reviewing the description of each new notification and attending daily management review committee meetings. Documents reviewed are listed in the Attachment A.

.2 Semi-Annual Review to Identify Trends

a. Inspection Scope

As required by Inspection Procedure 71152, "Identification and Resolution of Problems," the inspectors performed a review of PSEG's CAP and associated documents to identify trends that could indicate the existence of a more significant safety issue. The inspectors' review was focused on repetitive equipment and corrective maintenance issues, but also considered the results of daily inspector CAP item screening discussed in Section 4OA2.1. The review included issues documented in system health reports, corrective maintenance WOs, component status reports, site monthly meeting reports and maintenance rule assessments. The inspectors' review nominally considered the six-month period of December 2009 through May 2010, although some examples expanded beyond those dates when the scope of the trend warranted. The inspectors compared and contrasted their results with the results contained in PSEG's latest integrated quarterly assessment report. Corrective actions associated with a sample of the issues identified in PSEG's trend report were reviewed for adequacy. The inspectors also evaluated the trend report specified in SPP-3.1, Corrective Action Program. Documents reviewed are listed in the Attachment A.

b. Assessment and Observations

No findings of significance were identified.

The inspectors noted a trend of low level issues entered into the CAP related to equipment reliability. There were multiple issues with service water flow control valves and issues with the Unit 1 steam generator flow control regulating valves. The inspectors also noted deficiencies with the scope, planning, and implementation of long term equipment preventive maintenance. Some of the preventive maintenance deficiencies have been corrected through implementation of a performance centered maintenance plan. PSEG is aware of the issues identified through this trend review and is appropriately addressing these issues.

.3 Annual Sample: Transformer Load Tap Changer Failures

a. Inspection Scope

The inspectors reviewed PSEG's actions to investigate and identify the cause of the 12 station power transformer load tap changer failure that resulted in a reactor trip on December 28, 2007. The inspectors also reviewed PSEG's action towards identification and completion of corrective actions. The inspectors reviewed PSEG's procedures, vendor documents, notifications, orders, corrective actions, and root cause evaluations to understand the equipment functions and operational history, as well as the identification, evaluation, and corrective actions associated with the load tap changer failures. System engineers and other PSEG staff were interviewed to gain additional insights on the failures. Documents reviewed are listed in the Attachment A.

b. Findings and Observations

No findings of significance were identified.
The inspectors found that PSEG appropriately identified degraded conditions associated with load tap changer failures and entered them into the CAP. PSEG's root cause investigation determined the cause of the load tap changer failure to be inadequate scope of maintenance procedures on load tap changer internal components and insufficient performance monitoring of degraded load tap changer conditions. The investigations revealed severe coking of the selector switch components, which included damage to four of the six collector rings, and melted contacts. Inspectors determined that the evaluations of degraded conditions were thorough and included considerations for extent of condition. The inspectors reviewed PSEG's corrective actions and determined that they were appropriate to adequately address identified deficiencies.

4OA3 Event Follow-up (71153 - 1 sample)

.1 (Closed) LER 05000311/2010-002-01, Automatic Reactor

Trip Due to 21 Steam Generator Feedwater Pump (SGFP) Trip and Steam Generator Low Level

On January 21, 2010, at 1818 hours, the 21 SGFP tripped. A turbine runback automatically initiated as expected and steam generator level in all four steam generators (SG) lowered. The 22 SG reached the SG low level reactor trip setpoint at 1820 hours resulting in an automatic reactor trip. The turbine runback function initiated by the loss of 21 SGFP did not prevent a reactor trip as designed; however, this feature was not credited in the Salem accident analysis and, therefore, was not required to operate to maintain plant safety. All control rods fully inserted on the trip. All three AFW pumps started in response to the low SG water level and decay heat was removed by the steam dumps to the main condenser. Operators entered the emergency procedures for the plant trip and stabilized the plant in Mode 3.

The cause of the 21 SGFP trip was an internal wiring short in the SGFP control circuit that resulted in a false low suction pressure trip signal. The cause for the wiring short was the result of poor work practices. Corrective actions consist of lug inspections, document changes, training analysis, and evaluation of the integrated plant response to a SGFP from full power and implementing changes as appropriate. The inspectors completed a review of this LER and identified one finding of very low safety significance as documented in Section 1R12. This LER is closed.

b. Findings

The finding for this event is documented in Section 1R12.

4OA5 Temporary Instruction (TI) 2515/172

a. Inspection Scope

The Temporary Instruction (TI), 2515/172 provides for confirmation that owners of pressurized-water reactors (PWRs) have implemented the industry guidelines of the Materials Reliability Program (MRP) -139 regarding nondestructive examination and evaluation of certain dissimilar metal welds in the RCS containing nickel based Alloys 600/82/182.

During 1R20 PSEG inspected the dissimilar metal weld on the 1" reactor vessel drain piping with no detected indications. Salem Unit 1 has dissimilar metal welds in the eight reactor coolant system piping to reactor vessel nozzle safe end welds. No additional inspections or MSIP applications were performed during 1R20.

This TI requires documentation of specific questions in an inspection report. The questions and responses are included in this report as Attachment B.

b. Findings

No findings of significance were identified.

4OA6 Meetings, Including Exit

The inspectors presented the inspection results to Mr. C. Fricker and other members of PSEG management at the conclusion of the inspection on July 8, 2010. The inspectors asked PSEG whether any materials examined during the inspection were proprietary. No proprietary information was identified.

4OA7 Licensee Identified Violations

The following violation of NRC requirements was identified by PSEG. It was determined to have very low significance (Green) and to meet the criteria of Section VI of the NRC Enforcement Policy, NUREG-1600, for being dispositioned as a non-cited violation.

PSEG identified general corrosion that reduced the wall thickness of the safety related piping to less than the design minimum wall thickness of 0.278" for the system design pressure of 1950 psig. The lowest measured wall thickness was 0.077"; however, a finite element analysis for the degraded piping demonstrated past operability at a reduced operating pressure of 1275 psig.

10 CFR 50, Appendix B, Criterion III, Design Control requires in part that measures shall be established to assure that applicable regulatory requirements and design bases are correctly translated into specifications, drawings, and instructions and that these measures shall include provisions to assure the proper selection and review for suitability of application of materials, parts, equipment, and processes. During pipe excavation and inspections conducted as part of PSEGs buried piping program PSEG identified that it did not provide an effective protective coating for the buried section of AFW piping on Unit 1.

This finding was associated with the mitigating systems cornerstone, specifically the short term decay heat removal capability. The finding was determined to be Green because it was a design or qualification deficiency that was confirmed not to result in loss of operability of the AFW system. PSEG entered this condition into the corrective action program as notification 20456999.

ATTACHMENT A: SUPPLEMENTAL INFORMATION

ATTACHMENT B: TI 172 MSIP DOCUMENTATION QUESTIONS SALEM UNIT 1

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee personnel:
C. Fricker, Site Vice President
E. Eilola, Plant Manager
L. Rajkowski, Engineering Director
R. DeSanctis, Maintenance Director
J. Garecht, Operations Director
R. Gary, Radiation Protection Manager
J. Higgins, System Engineer
F. Hummel, System Engineer

LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Opened/Closed

05000272/2010003-01	NCV	Buried AFW Discharge Piping Not Tested In Accordance With 10 CFR 50.55a (Section 1R08)
05000311/2010003-02	FIN	21 Steam Generator Feed Pump Trip. (Section 1R12)

Closed

05000311/2010-002-01	LER	Automatic Reactor Trip Due to 21 SGFP Trip and Steam Generator Low Level (Section 4OA3.2)

LIST OF DOCUMENTS REVIEWED

In addition to the documents identified in the body of this report, the inspectors reviewed the following documents and records:

Section 1R01: Adverse Weather Protection

Procedures
SC.OP-AB.ZZ-0001(Q), Adverse Environmental Conditions, Revision 12
SC.OP-PT.ZZ-0002(Q), Station Preparations for Seasonal Conditions, Revision 11

Notifications
20377404 20415043 20437093 20437117 20446050 20449579
20465389

Orders

30120734	30180434	60053920	60081317	60081770	60083588
60083540	60083588	60087645	60087770	60088526	60089636
60090176					

Other Documents
2010 Salem Summer Seasonal Readiness Affirmation
WC-AA-107, Seasonal Readiness, Revision 10

Section 1R04: Equipment Alignment

Procedures
S1.OP-SO.CC-0002, 11 & 12 Component Cooling Heat Exchanger Operation, Revision 26
S1.OP-SO.SW-0002, 11 Nuclear Service Water Header Outage, Revision 26
S1.OP-ST.ZZ-0004 (Q), 92 Day Locked Valve Verification, Revision 3
S2.OP-SO.DG-0005, Preparation for Removing a Diesel Generator from Service, Revision 5
S2.OP-SO.SW-0005, Service Water System Operation, Revision 40

Drawings

224342	207482	207483	205236	AF-1-2B	AF-1-3A
AF-1-2A	205234				

Notifications

20458147	20458148	20468758

Other Documents
Tagging Work List 4263810, 12 SW HDR Hardening (11 OUTAGE) 1R20, 04/12/2010 @ 22:09

Section 1R05: Fire Protection

Procedures
FRS-II-433, Salem – Unit 1 (Unit 2) Pre-fire Plan, Auxiliary Feed Water Pumps Area Elevation 84'-0", Revision 6
FRS-II-435, Salem – Unit 1 (Unit 2) Pre-fire Plan, Diesel Fuel Oil Storage Area Elevation 84'-0", Revision 5
FRS-II-511, Salem – Unit 1 (Unit 2) Pre-fire Plan, Electrical Penetration Area Elevation 78'-0", Revision 5

Section 1R07: Heat Sink Performance

Procedures
ER-AA-340, GL 89-13 Program Implementing Procedure, Revision 4
ER-AA-340-1001, GL 89-13 Program Implementing Instructional Guide, Revision 6
ER-AA-340-1003, GL 89-13 Program PIs, Revision 2

Section 1R08: Inservice Inspection

Notifications:

20457869, Control Air Piping Leak*
20462034, Basis AFW Discharge Line Design Pressure*
20461785, Untimely retrieval of Design Documents*
20461255, U2 Containment Liner Blisters*
20459259, U2 Containment Liner Blisters*
20459689, failure to do IWA-5244 pressure tests*
20456999, Guided Wave (GW) pipe wall loss 20% to 44%*, in Equipment Apparent Cause Evaluation (EQ;ACE) Charter
20457854, see Equipment Apparent Cause Evaluation (EQ: ACE) Charter
20457869, Air Line Leak, in Equipment Apparent Cause Evaluation EQ: ACE Charter
20458147, see Equipment Apparent Cause Evaluation (EQ: ACE) Charter
20458148, see Equipment Apparent Cause Evaluation (EQ: ACE) Charter
20458568, see Equipment Apparent Cause Evaluation (EQ: ACE) Charter
20458554, 11 CA HDR Line In Fuel Xfer Area Degraded*
20458761, 1R20 CA Buried Pipe Coating Repair*
20458925, 1R20 SA Buried Pipe Coating Repair*
20457262, (88) 1R20 AF Buried Pipe Inspection Results*
20460624, Need Heat Trace on AF lines in FFT Area
20457877, U1 Containment Liner Corrosion at 78' El.*
20459259, U1 Corrosion on Containment Liner*
20459303, #14 AF pipe damaged penetration seal*
20459304, #12 AF pipe damaged penetration seal*
20459454, Request for Additional UT Data, 4/18/10 (due to 0.077" reading)*
20344017, Inspect steel liner in 1R19
20235636, NRC noted water running down containment wall
20459189, Question on location of RFO-14 location of a PZR shell weld
20290560, Replace section of 15B FWH shell-S1-R18
20457879, (184) 1R20 FAC(N18) 14# elbow below Tmin
20456828, (66) valve has visible boron buildup 1R20
20459232, Heavy Dry White Boron Vlv Packing (1R20)
20456834, Heavy Dry White Boron Vlv Packing (1R20)
20456840, Medium Dry White Boron Vlv Packing (1R20)
20456839, Medium Dry White Boron Vlv Packing (1R20)
20389147, Recordable ISI Indications on CVC Tank
20344017, Inspect Steel Liner in 1R19 @ Containment Sump
20235636, NRC Noted Water Running Down Containment Wall
20392631, ARMA From ISI Program Audit 2008
20460624, Need Heat Trace on AF lines in FTT Area
20333050, Response to NRC NOV EA-07-149
20322039, 2nd Interval ISI NRC Violation
20397518, A1CVC-1CV180 Chk Vlv Stuck Open - PI&R review
20444514, Boric Acid Leak from Drain Line - PI&R review
20445314, boron leak - PI&R review
20448241, Minor Packing Leak – BAC - PI&R review
20435861, 21SJ313 Has Boric Acid Leakage - PI&R review
20417331, Boric Acid Leak at 11 CV156 - PI&R review
20411151, Tubing leak on 1SS653 - PI&R review

20414343, 12 Charging Pump seal inj. Line - PI&R review
20395346, 12 Bat PP Seal Leak - PI&R review
20450330, Containment Liner Corrosion - PI&R review
20385733, Severe Corrosion on FP Valve - PI&R review
20438320, (217) Op Eval. Of Containment Corrosion - PI&R review
20387897, Significant outlet pipe corrosion - PI&R review
20397225, MIC Corrosion Causing Through Wall Leak - PI&R review
20436836, Repair Cracks in Battery Cells - PI&R review
20392145, Update U1 ISI Relief Request Book - PI&R review
20449447, Update Salem Unit 1 ISI 10 Yr Plan - PI&R review
20449744, Update Salem Unit 1 Containment ISI 10 Yr Plan - PI&R review
20449442, Update Salem Unit 2 Containment ISI 10 Yr Plan - PI&R review
20449554, Salem U2 RFO18 ISI Scope - PI&R review
20416605, INPO PSIRV Alloy 600 Program - PI&R review
20404057, Unit 2 ISI (MSIP) - PI&R review
20392631, ARMA FROM ISI PROGRAM AUDIT 2008 - PI&R review
20388065, Water leaking in decon room - PI&R review
20439023, 23 CFCU Head Leakage - PI&R review
20439022, SW Header Leakage 23 CFCU - PI&R review
20389148, 1R19 ISI Weld Exam Limitations - PI&R review
20416605, INPO PSIRV Alloy 600 Program - PI&R review
20449442, Update Salem 2 Containment ISI 10 yr. Plan - PI&R review
20449554, Salem Unit 2 RFO18 ISI Scope - PI&R review
20449747, Update Salem 2 ISI 10 Yr. Plan - PI&R review
20401542, Perform ISI BMV Exam on RPV Upper Head - PI&R review
20449063, SA U1 Service Inspec – ISI & U1 TI 2515 - PI&R review
20389147, Recordable ISI Indications on CVC Tank - PI&R review
20392145, Update U1 ISI Relief Request Book - PI&R review
20449744, Update Salem U1 Containment ISI 10 Yr. Plan - PI&R review
20409943, NRC RIS 2009-04 SG Tube Insp Rqmts – PI&R review
20459851, Section XI Exams Limited to 90% or Less – PI&R review
20450520, Recoat Affected Areas of Liner 2R18 – PI&R review
20457388, Excavation Issues – PI&R review

*Denotes this Notification was generated as a result of this inspection

Section XI Repair/Replacement Samples:

W.O. 60079414, 14" Carbon Steel Elbow FAC indication below minimum wall
W.O. 60084266, Salem U1 AF Buried Piping Inspection
W.O. 60089561, 80101381: Replace Aux FW U/G Piping
W.O. 60064104, Repair 15B FWH Area
W.O. 60084375, BACC Program repair to 1PS1
W.O. 60089612, BACC Program repair to S1CVC-14CV392
W.O. 60089615, BACC Program repair to S1SJ-13SJ25
W.O. 60089848, 80101382 Advanced Work Authorization #2 FTTA Replace Aux. Feedwater Pipe
W.O. 60089561, 80101381 Advanced Work Authorization – Replace Aux. FW U/G Piping, 4/9/10

Non-Code Repair

W.O. 60089848, Repair Non-nuclear, safety related CA Pipe, Unit 1 FTTA
W.O. 60089757, Test Non-nuclear, safety related CA Pipe Repair, Unit 1 FTTA

Miscellaneous Work Orders:

W.O. 60089917, Penetrations for CA & SA Lines, 4/23/10
W.O. 941017262, Activity 04, Excavate and Examine Auxiliary Feedwater Piping, Unit 2, 12/94
W.O. 941017262, Activity 03, Excavate and Examine Auxiliary Feedwater Piping, Unit 2, 12/94
W.O. 941017262, Activity 02, Excavate and Examine Auxiliary Feedwater Piping, Unit 2, 12/94
W.O. 941017262, Activity 01, Excavate and Examine Auxiliary Feedwater Piping, Unit 2, 12/94
W.O. 60089561, Flush New AFW piping 12 and 14

Drawings & Sketches:

205236A8761-54, Salem Nuclear Generating Station, Unit No. 1, Auxiliary Feedwater
Salem Unit 1 Aux Feed Piping, Allan Johnson, 4/10/10
80101381RO, Buried Pipe, Replaced AFW Piping Arrangement
207483A8923-11, Salem Nuclear Generating Station, Unit No. 1 – Reactor Containment Auxiliary Feedwater, Plans & Sections – Elev. 78' 10" & 100' 0", Mechanical Arrangement, Revision 8, 9/31/86
207483A8923-28, Sheet 1 of 4, Salem Nuclear Generating Station, Unit No. 1 – Reactor Containment Auxiliary Feedwater, Plans & Sections – Elev. 84',Mechanical Arrangement, Revision 8, 9/31/86
207483A8923-31, Sheet 2 of 4, Salem Nuclear Generating Station, Unit No. 1 – Reactor Containment Auxiliary Feedwater, Plans & Sections – Elev. 84', Mechanical Arrangement, Revision 8, 9/31/86
207483A8923-28, Sheet 3 of 4, Salem Nuclear Generating Station, Unit No. 1 – Reactor Containment Auxiliary Feedwater, Plans & Sections – Elev. 84',Mechanical Arrangement, Revision 8, 9/31/86
207483A8923-30, Salem Nuclear Generating Station, Unit No. 1 – Reactor Containment Auxiliary Feedwater, Plans & Sections – Elev. 84',Mechanical Arrangement, Revision 8, 9/31/86
207610A8896-12, Salem Nuclear Generating Station, Unit No. 1 – Auxiliary Building & Reactor Containment Compressed Air Piping, Aux. Building El. 84 East & React. Contain. El. 78, Mechanical Arrangement, Revision 8, 9/31/86

Design Change Packages/Equivalent Change Packages

80101382, Revision 2, Replace Salem Unit 1 AFW Piping from the Unit Mechanical Penetration Area El. 78'-0" to the Unit 1 Fuel Transfer Tube Area El. 100'-0"
80101381, Revision 1, Replace in-kind the Salem Unit 1 AF Piping that runs underground from the Unit 1 Fuel Transfer Tube Area to the Unit 1 Main Steam Outer Penetration Area

50.59 Applicability Reviews, Screenings & Evaluations

80101382; Salem Unit 1 12/14 AF Piping Reroute; 4/24/10

System & Program Health Reports & Self-Assessments:

Salem Boric Acid Corrosion Control Program Focused Area Self-Assessment, 1/2010
70106830, Salem S1R20 NRC ISI Inspection Check-In Self Assessment
70095327, Salem Boric Acid Corrosion Control Program Focused Area Self-Assessment, 4/29/09

Program Documents

PSEG Nuclear Salem Units 1 & 2, Alloy 600 Management Plan, Long Term Plan (LTP), Revision 2, Integrated Strategic Plan For Long Term Protection from Primary Water Stress Corrosion Cracking (PWSCC), 10/15/09
ASME, Section XI,1998 Edition, 2000 Addenda, IWA-5244 Buried Components
OAR-1, Owner's Activity Report, #S1RFO19, 1/15/09

Procedures

DETAILED AND GENERAL, VT-1 AND VT-3 VISUAL EXAMINATION OF ASME CLASS MC AND CC CONTAINMENT SURFACES AND COMPONENTS
SH.RA - AP.ZZ - 8805(Q) - Revision 4, 8/31/06; Boric Acid Corrosion Management Program
ER - AP - 331, Revision 4, Boric Acid Corrosion Control (BACC) Program
ER - AP - 331 - 1001, Revision 2, Boric Acid Corrosion Control (BACC) Inspection Locations, Implementation And inspection Guidelines
ER - AP - 331 - 1002, Revision 3, Boric Acid Corrosion Control (BACC) Program Identification, Screening, and Evaluation
ER - AP - 331 - 1003, Revision 1, RCS Leakage Monitoring And Action Plan
ER - AP - 331 - 1004, Revision 2, Boric Acid Corrosion Control (BACC) Program Training and Qualification
ER - AA - 330 - 001, Revision 7, SECTION XI PRESSURE TESTING
LS - AA - 125, Revision 13; Corrective Action Program (CAP) Procedure
LS - AA - 120, Revision 8; Issue Identification And Screening Process
SH.RA-IS.ZZ-0005(Q)-Revision 6; VT-2 Visual Examination Of Nuclear Class 1, 2 and 3 Systems
SH.RA-IS.ZZ-0150(Q) – Revision 8, 10/19/04; Nuclear Class 1, 2, 3 and MC Component Support Visual Examination
OU-AP-335-043, Revision 0; BARE METAL VISUAL EXAMINATION (VE) OF CLASS 1 PWR COMPONENTS CONTAINING ALLOY 600/82/182 AND CLASS 1 PWR REACTOR VESSEL UPPER HEADS
OU-AA-335-015, Revision 0; VT 2 - VISUAL EXAMINATION
Areva NP, Inc., Engineering Information Record 51-9118973-000; Qualified Eddy Current Examination Techniques for Salem Unit 1 Areva Steam Generators, 10/15/09
AREVA NP 03-9123233, Revision 000, 10/13/09; Salem Unit 2 RVCH Flange Repair
SC.MD-GP.ZZ-0035(Q) – Revision 9, PRESSURE TESTING OF NUCLEAR CLASS 2 AND 3 COMPONENTS AND SYSTEMS, 02/02/10
SH.MD-GP.ZZ-0240(Q) – Revision 10, SYSTEM PRESSURE TEST AT NORMAL OPERATING PRESSURE AND TEMPERATURE, 7/29/09
S2.OP-AF-0007(Q)-Revision 20, 12/23/09; INSERVICE TESTING AUXILIARY FEEDWATER VALVES, MODE 3
ER-AA-5400-1002, Revision 1, BURIED PIPING EXAMINATION GUIDE
Specification No. S-C-MPOO-MGS-0001; Piping Schedule SPS54, Auxiliary Feedwater, Revision 6
PSEG Test Procedure 10-H-8-R1, Unit 2 Auxiliary Feedwater 2100/2150 Hydro; 9/21/78

NDE Examination Reports & Data Sheets

003753, VT-10-113, PRV nozzle sliding support
003754, VT-10-114, RPV nozzle sliding support
006325, UT-10-041, PZR longitudinal shell weld J (100%)
007500, UT-10-132, PZR surge line nozzle (100%)
007901, UT-10-028, 13 SG lower head to tubesheet weld (67%)
006073, VE-10-026, CRDM TO VESSEL PENETRATION WELD, 4/12/10
008001, VE-10-027, 31-RCN-1130-IRS
008026, VE-10-028, 29-RCN-1130-IRS
009070, VE-10-030, 12-STG Channel Head Drain (100%)
033300, UT-10-027, 4-PS-1131-27 (100%)
033200, UT-10-029, 4-PS-1131-26 (100%)
033100, UT-10-032, 4-PS-1131-25 (100%)
032300, UT-10-033, 4-PS-1131-17 (100%)
031700, UT-10-040, 4-PS-1131-12 (100%)
032600, UT-10-034, 4-PS-1131-20 (100%)
047600, UT-10-045, 29-RC-1140-3 (100%)
051200, UT-10-048, 29-RC-1120-3 (100%)
203901, UT-10-047, 32-MSN-2111-1 (100%)
204001, UT-10-046, 16-BFN-2111-1 (70.64%)
210586, UT-10-025, 14-BF-2141-19 (100%)
210588, UT-10-024, 14-BF-2141-20 (100%)
836300, IWE: VT-10-338, PNL-S1-343-1
836400, IWE: VT-10-333, ALK-S1-100-tubing
840000, IWE: Vert Leak Channels 1 – 14
006073, VE-10-026, RPV Upper Head Inspection
006051, PT-10-004, CRDM Housing Weld Exams, penetrations #66, 67, and 72
Salem Unit 1, VT-2, Visual Examination Record, 12/14 AF FTTA, W.O. 60089848, 4/26/10 (VT)
Salem Unit 1, VT-2, CA Repair Snoop Test, W.O. 60089575, 4/27/10
Salem Unit 1, UT, W.O. 60084266, Yard AF, 4/18/10
Salem Unit 2, UT, W.O.60089851, Exam of containment liner
Salem Unit 1, UT 1-SGF-31-L2 FW elbow below min. wall
Salem Unit 1, UT, W.O. 30176541, 1-SGF-31-L2 FW elbow below min. wall
Salem Unit 1, UT, W.O. 60084266, AFW
Order 50113214, ST 550D, Surveillance: ISI Perform PORV Check
Order 50118090, ST 550D, Surveillance: OPS Perform PORV Check
W.O. 60089848, VT-2 Visual Examination Record, 12/14 AFW in FTTA, 4/26/10
W.O. 941017262, Activity 02; Salem Unit 2, Excavate and Examine Auxiliary Feedwater Piping, 12/2/94
W.O. 60084266, UT Unit 1 AFW (thinnest area), 4/20/10
UT Analysis, Component 1-SGF-31-L2 (14" FW Elbow below Minimum wall), 4/10/10
W.O. 60089851, Unit 2 Containment Liner blister UT measurements, 4/21/10
W.O. 60086175, Unit 1 Containment corrosion 78' elevation
W.O. 60084266, Unit 1 AFW piping UT measurements, 4/12/10
W.O. 30176541, Unit 1 AFW piping UT measurements, 4/12/10
W.O. 60084266, Unit 1 AFW piping UT measurements, 4/7/10
W.O. 60084266, Unit 1 AFW piping UT measurements, 4/5/10
W.O. 60084266, Unit 1 AFW pipe UT measurements at supports, 4/18/10
W.O. 30176541, Unit 1 CA piping UT measurements in FTTA
401600, VE-04-198; Hope Creek system pressure test CST to HPCI/RCIC and Core Spray,

11/5/04
VT-2, Salem Unit 1 AF 12 & 14 Pressure Test, 4/25/10
W.O. 60089661, UT measurements, Unit 2 AFW Piping #24 in FTTA, 4/25/10
W.O. 60089661, UT measurements, Unit 2 AFW Piping #22 in FTTA, 4/26/10

Eddy Current Testing Personnel Qualification Records

A2421
B8731
B0500
B5127
B5128
B2576
F3961
C1560
D7895
D9573
D6502
H2039
K5380
M9460
E0427
M6664
B4260
A3502
J9815
P5436
M6042
B8589
B4014
G2573
V8530
W3368
M4305
B4052
C2028
C4596
C3340
D3858
H6267
H0282
I4048
J1978
2010983302133
P6459
R0830
R1164
S0608
2509981330193
K5858
1007951330114
L9168
L4332
F7460
F0037
3107943330158
6206070744
6507061922
1803983330125
2709977301226
P5304
P4006
R4201
R6452
R8002
S7752
T8251
V3197
R4142
R6279
G3380
B3720
R6900
A9608
N2574
I3805
T2170
N4815
M0945
P2963
M9715
K1903
D5318
W6070
M5096
J1945
L4588
C8042
N5330
L8267
F3453
T5616
R9311
G4943
C5542
F0075
F6623
F3453
G4943
G1311
H7791
J9141
M0950
M2665
M7006
M9459
M7007
M9082
N7035
N9952
R9311
S9098
T5616
T5565
W2639
W7912
K6975
G3910
H0268
L3025
P1465
B8079
G1756
C8071
6410058746
B5371
H2131
2909965330076

Engineering Analyses & Calculations & Standards

Calculation 6SO-1882, Revision 1, 8/30/96; Qualification of Safety-Related Buried Commodities For Tornado Missle and Seismic Evaluation
Calculation No. S-C-AF-MDC-1789; Salem Auxiliary Feedwater Thermal Hydraulic Flow Model, 10/4/00
70087436, Steam Generator Degradation & Operational Assessment Validation, Salem Unit 1 Refueling Outage 18 (1R18) & Cycles 19/20, 9/2008
51-9052270-000, Update – Salem Unit 1 SG Operational Assessment At 1R18 For Cycles 19 and 20, 10/1/08
51-9048311-002, Salem Unit 1 SG Condition Monitoring For 1R18 And Preliminary Operational Assessment For Cycles 19 and 20, 10/30/07
701086998-0050, Maximum Pressure in Underground Auxiliary Feedwater Piping
60089575-130, Past Operability Determination for the leak in the one inch air line to air operated valves in Unit 1 South Penetration Area
70109233/20459231; Boric Acid evaluation of leakage from S1CVC-1CV277
70109232/20459230; Boric Acid evaluation of leakage from S1CVC-1CV2
70109230/20459228; Boric Acid evaluation of leakage from S2RC-1PS1
70109234/20459232; Boric Acid evaluation of leakage from S1SJ-13SJ25
70108698/30, Operating Experience Report for degraded Unit 1 AFW piping
51-9135923-000, AREVA; Salem unit 1 SG Condition Monitoring For 1R20 and Preliminary Operational Assessment For Cycles 21 And 22, 4/20/10
SA-SURV-2010-001, Revision 1; Risk Assessment of Missed Surveillance – Auxiliary Feedwater discharge line underground piping pressure testing, 4/23/10
CQ9503151526; SCI-94-0877, EXCAVATED AUXILIARY PIPING WALKDOWN/DISPOSITION OF COATING REQUIREMENTS; 12/16/94
Specification No. S-C-M600-NDS-019, COATINGS INTERIOR/EXTERIOR SURFACES CARBON STEEL SERVICE WATER PIPING, NO. 12 COMPONENT COOLING HEAT EXCHANGER ROOM AUXILIARY BUILDING (ELEVATION 84)
Structural Integrity Associates, Inc. Calculation File No. 1000494.301, Evaluation of Degraded Underground Auxiliary Feedwater Piping (Between Unit 1 FTTA and OPA), 4/23/10
Technical Evaluation 60089575-0140, Acceptability of CA Piping in the Fuel Transfer Area, 4/29/10
Technical Evaluation 60089848-0960, Auxiliary Feedwater Piping Missle Barrier Exclusion, 4/29/10
Structural Integrity Associates, Inc. Calculation File No. 1000498.301, Evaluation of Thinned Feedwater Elbow, 4/22/10
Technical Evaluation 70108698-0050, Maximum Pressure in Underground Auxiliary Feedwater Piping, 4/29/10
SPECIFICATION NO. S-C-MPOO-MGS-0001, Piping Schedule SPS54 AUXILIARY FEEDWATER, Revision 6
OpEval. #10-005, Salem Unit 2 Operability Evaluation, Received 5/18/10
Technical Evaluation 60084266-105-20, Alternative Exterior Coatings for Buried Piping, AF, CA, SA and Pipe Supports Under W.O. 60084266, 4/2/10
Technical Evaluation H-1-EA-PEE-1871, Hope Creek Service Piping Coatings Alternatives, 80075587, Revision 0, 10/15/04
PSEG Nuclear, LLC, Technical Standard, Coating Systems and Color Schedules, Revision 5, 4/3/06

Weld Records – AFW Piping Repair (W.O. #'s 60084266, 60089561, 60089798, 60089848)

Multiple Weld History Record: 74626
Multiple Weld History Record: 74556
Multiple Weld History Record: 74557
Multiple Weld History Record: 74558
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Multiple Weld History Record: 74562
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Multiple Weld History Record: 74602
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Multiple Weld History Record: 74623
Multiple Weld History Record: 74622
Multiple Weld History Record: 74621
Multiple Weld History Record: 74537
Multiple Weld History Record: 74538
Multiple Weld History Record: 74537
Welder Stamp Number: P-664
Welder Stamp Number: P-65
Welder Stamp Number: P-466
Welder Stamp Number: P-57
Welder Stamp Number: E-64
Welder Stamp Number: P-710
Welder Stamp Number: P-207
Welder Stamp Number: P-666
Welder Stamp Number: P-708
Welder Stamp Number: E-89
Welder Stamp Number: P-84
Welder Stamp Number: P-228
Surface Exam Record: 60089561-0041
Surface Exam Record: 60089848-0001
Surface Exam Record: 60089848-0001
Surface Exam Record: 60089561-0041
Surface Exam Record: 60089561-0860

Miscellaneous Documents

Salem Unit 1 & Salem Unit 2 Technical Specification, 3.4.11 STRUCTURAL INTEGRITY, ASME CODE CLASS 1, 2 AND 3 COMPONENTS
Electric Power Research Institute (EPRI), Steam Generator Integrity Assessment Guidelines, Technical Report 1012987, Revision 2, July 2006
NRC Letter dated 3/11/91; FIRST TEN-YEARINSPECTION INTERVAL, INSERVICE INSPECTION PROGRAM RELIEF REQUEST, SALEM NUCLEAR GENERATING STATION, UNIT 1 (TAC NOS. 66013 AND 71101)

PSEG Nuclear, Salem Unit 1 & 2 Alloy 600 Management Plan, Long Term Plan (LTP), Revision 2, 10/15/09
Salem Unit 1 – Buried Piping Risk Ranking
MPR Associates Report, Technical Input To Operability of Potential Containment Liner Corrosion, Revision 0, 10/30/09
Transmittal of Design Information #S-TODI-2010-0005, 4/20/2010
Transmittal of Design Information #S-TODI-2010-0004, 4/16/2010
OQ950315126, PSEG ltr. Dated 12/16/94; Excavated Auxiliary Feedwater Piping Walkdown/Disposition of Coating Requirements
PSEG letter LR-N07-0224 dated 9/13/2007; REPLY TO NOTICE OF VIOLATION EA-07-149
UNTAGGING WORKLIST 4274446, 14 AF Underground Piping 1R20, 4/30/10
UNTAGGING WORKLIST 4274351, 12 AF Underground Piping 1R20, 4/30/10

Section 1R11: Licensed Operator Requalification Program

Procedures
TQ-AA-301, Simulator Configuration Management, Revision 13
2-EOP-TRIP-1, Reactor Trip or Safety Injection, Revision 27
2-EOP-TRIP-2, Reactor Trip Response, Revision 27

Section 1R12: Maintenance Effectiveness

Procedures
ER-AA-310, Implementation of the Maintenance Rule, Revision 7
ER-AA-310-1001, Maintenance Rule – Scoping, Revision 4
ER-AA-310-1003, Maintenance Rule - Performance Criteria Selection, Revision 4
ER-AA-310-1004, Maintenance Rule - Performance Monitoring, Revision 7
ER-AA-310-1005, Maintenance Rule - Dispositioning Between (a)(1) and (a)(2), Revision 7

Notifications

20442453	20456501	20465774	20416718	20409963	20406324
20447948	20373131	20382756	20417863	20377572	20437243
20381571	20444082	20409557			

Orders

70104875	70106673	70108607	70108825	70108907	70097082

Other Documents
Salem Nuclear Generating Station Maintenance Rule System Function and Risk Radiation Monitoring Report, dated May 26, 2010
Salem 1 Narrative Log, dated May 26, 2010
Salem 2 Narrative Log, dated May 26, 2010
Salem 1 and Salem 2, System Health Report (Q4-2009), Radiation Monitoring System

Section 1R13: Maintenance Risk Assessments and Emergent Work Control

Procedures
S1.OP-SO.4KV-0002, 1B 4KV Vital Bus Operation, Revision 33
S1.OP-SO.SF-0002, Spent Fuel Cooling System Operation, Revision 20
OU-AA-103, Shutdown Safety Management Program, Revision 12

SC.OM-AP.ZZ-0001, Shutdown Safety Management Program – Salem Annex, Revision 4
ER-AA-600-1016, ORAM-Sentinel and Paragon Tool Update, Revision 6
S1.OP-ST.4KV-0001, Electrical Power Systems 4KV Vital Bus Transfer, Revision 13
S1.OP-AB.4KV-0003, Loss of 1C 4KV Vital Bus, Revision 8
S1.OP-AB.460-0003, Loss of 1C 460/230V Vital Bus, Revision 7
S1.MD-FR.SF-0001, Alternate Power Source for No. 11 & 12 Spent Fuel Pool Cooling Pumps, Revision 6

Drawings

203049	203110	203111	203112	203113	203072

Notifications

20458435	20459055	20459059

Other Documents
Salem Unit 1 Shutdown Risk Status Sheet, April 5, 2010 @ 17:00
SGS Unit 2 PRA Risk Evaluation Form for Work Week 014 (March 28 to April 3, 2010), Revision 2
SGS Unit 2 PRA Risk Evaluation Form for Work Week 015 (April 4 to 10, 2010), Revision 0
Salem Unit 1 Shutdown Risk Status Sheet, April 8, 2010 @ 17:00
Tagging Work List 4265994, 12 SFP Pump Alt Feed 1R20, April 12, 2010 @ 19:11
SOD-2010-013, Salem Operations Directive re: Mid-loop Operations, dated April 16, 2010
Salem 1 Narrative Log, dated April 16, 2010

Section 1R15: Operability Evaluations

Procedures
S1.OP-ST.CVC-0008, Reactivity Control Systems – Boration, Revision 7
S1.OP-ST.CVC-0009, Reactivity Control Systems – Boration, Revision 18
S1.MD-ST.SW-0002, Service Water Bays 1 and 3 Outage Inspection and Repair, Revision 4
S1.OP-ST.4KV-0001, Electrical Power Systems 4KV Vital Bus Transfer, Revision 13
S1.OP-AB.4KV-0003, Loss of 1C 4KV Vital Bus, Revision 8
S1.OP-AB.460-0003, Loss of 1C 460/230V Vital Bus, Revision 7
S1.OP-AB.SG-0001(Q), Steam Generator Tube Leak, Revision 19
S2.OP-PM.CC-0021(Q), 21 Component Cooling Heat Exchanger High Flow Flush and Alignment, Revision 19

Drawings

223678	223677	223676

Notifications

20435078	20456624	20456318	20153925	20457213	20457563
20457677	20459689	20462034	20461785	20459454	20459204
20458761	20458925	20463859	20463695	20460078	20460278
20464903	20460285				

Orders

70108864	70110454	70109482	70108698	70109522

Other Documents
Calculation Number 267747, Service Water Pumphouse Piping – Bay 1, Revision 9
SWPS-0005, Design Calculation for SWPS-5, Revision 2
SA-SURV-2010-001, Risk Assessment of Missed Surveillance – Auxiliary Feedwater Discharge Line Underground Piping Pressure Testing, Revision 1

Section 1R18: Plant Modifications

Procedures
S1.MD-FR.SF-0001, Alternate Power Source for No. 11 & 12 Spent Fuel Pool Cooling Pumps, Revision 6
Design Changes
Design Change No. 80098748, Modify Pressurizer Spray Valve Internals, Revision 0

Notifications
20458361 20466937

Drawings
D-401193, Revision 1 D-401194, Revision 5

Orders
70104696 80101774

Other Documents
S2010-183, 50.59 Screening for TCCP 1ST-012, Revision 0
TCCP 1ST10-012, Plug 13BF19-AO Air Supply Regulator Weep Hole, Revision 0

Section 1R19: Post-Maintenance Testing

Procedures
MA-AA-716-012, Post Maintenance Testing, Revision 14
SC.MD-PM.115-0001, 10/12 KVA Vital Instrument Bus Inverter Preventive Maintenance, Revision 12
S1.OP-ST.4KV-0002, Electrical Power Systems AC Distribution, Revision 22
S2.OP-PM.CC-0022(Q), 22 Component Cooling Heat Exchanger High Flow Flush and Alignment, Revision 16
SC.MD-PM.SW-0010(Q), Disassembly, Inspection and Repair of Masoneilan Butterfly Valve Mark # AA-103, Revision 2
S2.OP-PM.CC-0021(Q), 21 Component Cooling Heat Exchanger High Flow Flush and Alignment, Revision 19
SH.IC-GP.ZZ-0003(Q), Removal and Installation of Masoneilan Domotor Actuator, Revision 2
S2.OP-ST.AF-0002(Q), Inservice Testing – 22 Auxiliary Feedwater Pump, Revision 18
S2.OP-ST.SJ-0001(Q), Inservice Testing – 21 Safety Injection Pump, Revision 19

Notifications
20296405 20463859 20464983 20463639 20463658

Orders
30156599 30152753 60090391 60090348 60088790

Drawings
A-6207

Other Documents
1A VIB Inverter, Rectifier Inverter Parts Replacement & Test Plan
1A VIB Inverter, Regulator & Static Switch Parts Replacement & Test Plan
Salem 2 Narrative Log, dated May 10, 2010
Salem 2 Narrative Log, dated May 19, 2010
Prompt Investigation Report, 21 CC Heat Exchanger Unexpected Low Flow during High Flow Flush
Salem 2 Narrative Log, dated May 21, 2010
PMI Tool, Template for 21 SW122

Section 1R20: Refueling and Outage Activities

Procedures
S1.OP-SO.RC-0006(Q), Draining the Reactor Coolant System <101 Ft. Elevation with Fuel in the Vessel, Revision 26
S1.OP-IO.ZZ-0005(Q), Minimum Load to Hot Standby, Revision 18
S1.OP-IO.ZZ-0006(Q), Hot Standby to Cold Shutdown, Revision 33

Notifications
20453674 20461909 20460492 20460347 20460313 20453797

Orders
70107017

Other Documents
Fatigue Assessments and Waivers, January 1, 2010 – April 21, 2010
ORAM Contingency Plan, RCS at Mid-Loop Post-Refueling
1R20 Outage Risk Assessment Report, Initial Schedule Approval, Revision 0
Salem 1R20 Level 2 with Operations Testing Chart
Salem 1R20 Major Work Scope List

Section 1R22: Surveillance Testing

Procedures
S1.OP-ST.RHR-0005, Residual Heat Removal Valves and Orifices, Revision 6
S1.OP-ST.MS-0003, Steam Line Isolation and Response Time Testing, Revision 9
S1.OP-ST.TRB-0002, Turbine Protection System – Full Functional Test, Revision 17
S1.OP-ST.MS-0002, Inservice Testing – Main Steam and Feedwater Valves, Revision 11
ER-AA-321, Administrative Requirements for Inservice Testing, Revision 10
S1.OP-ST.SJ-0015, Intermediate head Hot Leg Throttling Valve Flow Balance Verification, Revision 18
S1.MD-AP.ZZ-0012, Salem Mode Change Requirements, Revision 14
SC.MD-DC.RC-0003, Calibration of Pressurizer Safety Relief Valve Indicating Switches, Revision 5
S1.OP-LR.FP-0001(Q), Type C Leak Rate Test 1FP147 and 1FP148, Revision 0
S1.OP-LR.CVC-0003(Q), Type C Leak Rate Test 1CV116, 1CV284 and 1CV296, Revision 0
S2.OP-ST.SJ-0001(Q), Inservice Testing – 21 Safety Injection Pump, Revision 19
S1.OP-ST.AF-0007(Q), Inservice Testing Auxiliary Feedwater Valves Mode 3, Revision 19

S1.RA-ST.AF-0007(Q), Inservice Testing Auxiliary Feedwater Valves Mode 3 Acceptance Criteria, Revision 7

Drawings
EHC-1: Simple EHC, Revision2

Notifications

20321206	20460597	20461042	20458712	20457236	20458026
20444513	20462371	20462544	20456929		

Other Documents
PR #971003209, MSIV Emergency Hydraulic Override Not Tested
Salem 2 Narrative Log, dated April 24, 2010
Salem 2 Narrative Log, dated May 8, 2010
Adverse Condition Monitoring and Contingency Plan, 21 Safety Injection Outboard Bearing Housing Oil Leak Rate

Section 1EP6: Drill Evaluation

Procedures
NC.EP-EP-0102, Emergency Coordinator Response, Revision 14
1-EOP-TRIP-1, Reactor Trip or Safety Injection, Revision 26

Other Documents
Emergency Preparedness NRC Graded Exercise S10-03 Critique Report
Salem Event Classification Guides
SGS EAL/RAL Technical Basis, Salem Generating Station Emergency Action Level/Reporting Action Level Technical Basis Document, Revision 8
S10-03, Salem Graded Exercise Scenario Synopsis

Section 2RS1: Radiological Hazard Assessment and Exposure Controls

Other Documents

Radiation Work Permit #1 Tasks: 4040; 1210404; 23; 27

Section 2RS2: Occupational ALARA Planning and Controls

Other Documents
Daily ALARA Dose Summary Reports, 1R20, dated April 12-16, 2010
ALARA Reviews: 1/4040; 1/1210404; 1/23; 1/27

Section 4OA1: Performance Indicator Verification

Other Documents
Salem 1 and Salem 2, 1Q/2010 Performance Indicators, Unplanned Scrams per 7000 Critical Hrs
Salem 1 and Salem 2, 1Q/2010 Performance Indicators, Unplanned Power Changes per 7000 Critical Hrs
Salem 1 and Salem 2, 1Q/2010 Performance Indicators, Unplanned Scrams with Complications

Section 4OA2: Identification and Resolution of Problems

Procedures
SC.MD-PM.13-0003(Q), Westinghouse 13/4KV Power Transformers 11,12 & 21 Preventive Maintenance, Rev. 4

Notifications

20329373	20330305	20342653	20350143	20370234	20430448
20443177	20443537				

Orders

70078697	70101758

Other Documents
Nuclear Oversight Assessment Report, January thru April 2010
Salem Top Ten Low Margin Issues List, Approved June 9, 2010
Salem Critical Component Failure Clock, dated June 18, 2010
Level 1 – 4 Notifications List, December 2009 – May 2010
Salem Top 10 Equipment Issues List, dated May 4, 2010
Salem Units 1 and 2 40 Non-Outage List, dated June 18, 2010

LIST OF ACRONYMS

ADAMS	Agency-wide Documents Access and Management System
AFW	Auxiliary Feedwater
ALARA	As Low As Reasonably Achievable
AOV	Air Operated Valve
CAP	Corrective Action Program
CC	Component Cooling
CCW	Component Cooling Water
CFR	Code of Federal Regulation
EDG	Emergency Diesel Generator
ESOC	Electrical System Operations Center
GL	Generic Letter
HRA	High Radiation Area
HX	Heat Exchanger
IMC	Inspection Manual Chapter
NCV	Non-cited Violation
NEI	Nuclear Energy Institute
NRC	Nuclear Regulatory Commission
OSP	Off-site power
OOS	Out-of-Service
PARS	Publicly Available Records
PI	Performance Indicator
PMT	Post-Maintenance Testing
PSEG	Public Service Enterprise Group Nuclear LLC
RCS	Reactor Coolant System
RFO	Refueling Outage
RWP	Radiation Work Permit

SDP	Significance Determination Process
SFP	Spent Fuel Pool
SW	Service Water
TS	Technical Specifications
WO	Work Order

Attachment B

TI 172 MSIP Documentation Questions Salem Unit 1

Introduction:

The Temporary Instruction (TI), 2515/172 provides for confirmation that owners of pressurized-water reactors (PWRs) have implemented the industry guidelines of the Materials Reliability Program (MRP) -139 regarding nondestructive examination and evaluation of certain dissimilar metal welds in the RCS containing nickel based Alloys 600/82/182. This TI requires documentation of specific questions in an inspection report. The questions and responses for MSIP for the IR 05000311/2009005 section 4OA5 are included in this Attachment.

In summary the Salem Units 1 and 2 have MRP-139 applicable Alloy 600/82/182 RCS welds in the four hot and four cold leg piping to reactor pressure vessel nozzle connections for each plant.

For Unit 1 during the 1R20 refueling outage in April 2010 PSEG inspected one dissimilar metal weld, a SG channel head drain line weld. No indications were reported from this inspection. PSEG plans on replacing this valve, and the dissimilar metal weld, during refueling outage 1R22.

TI 2515/172 requires the following questions to be answered for MRP-139 MSIP inspections:

Question 1: For each mechanical stress improvement used by the licensee during the Salem U1 1R20 outage, was the activity performed in accordance with a documented qualification report for stress improvement processes and in accordance with demonstrated procedures?

Response Question 1: No MSIP activities were conducted on U1 during 1R20.

Question d.1: Are the nozzle, weld, safe end, and pipe configurations, as applicable, consistent with the configuration addressed in the stress improvement (SI) qualification report?

Response – Question d.1: No MSIP activities were conducted on U1 during 1R20.

Question d.2.: Does the SI qualification report address the location radial loading is applied, the applied load, and the effect that plastic deformation of the pipe configuration may have on the ability to conduct volumetric examinations?

Response Question d.2: No MSIP activities were conducted on U1 during 1R20.

Question d.3.: Do the licensee's inspection procedure records document that a volumetric examination per the ASME Code, Section XI, Appendix VIII was performed prior to and after the application of the MSIP?

Response: Question d.3.: No MSIP activities were conducted on U1 during 1 R20.

Question d.4.: Does the SI qualification report address limiting flaw sizes that may be found during pre-SI and post-SI inspections and that any flaws identified during the volumetric examination are to be within the limiting flaw sizes established by the SI qualification report?

Response: Question d.4.: No MSIP activities were conducted on U1 during 1 R20.

Question d.5.: Was the MSIP performed such that deficiencies were identified, dispositioned, and resolved?

Response Question d.5.: No MSIP activities were conducted on U1 during 1 R20.

AFW WRITEUP FEED BACK

Rejectable Indication Accepted For Service After Analysis:

The inspector reviewed the Notification and the UT data report of a rejectable wall thickness measurement on the #11 SG Feedwater elbow during 1R20. The inspector reviewed the additional wall thickness data taken to further define the condition and reviewed the finite element analysis (FEA) which verified that sufficient wall thickness remained to operate the component until the next refueling outage when it will be replaced.

b. Finding

of AFW

Introduction. The inspector identified a GREEN non-cited violation (NCV) of 10 CFR 50.55a(g)(4) and the referenced American Society of Mechanical Engineers (ASME) Code, Section XI, paragraph IWA-5244 for PSEG's failure to perform required pressure tests of buried components for Salem Unit 1. This piping is safety related, 4.0" ID, ASME Class 3, Seismic Class 1 piping.

Description. Portions of the Unit 1 and Unit 2 Auxiliary Feedwater (AFW) System piping is buried piping and has not been visually inspected since the plant began operation in 1977 for Unit 1 and since 1979 for Salem Unit 2. In April 2010, approximately 680 ft. (340 ft. of the #12 SG AFW supply and 340 ft. of the #14 SG AFW supply) of piping between the pump discharge manifold and the connection to the Main Feedwater piping to the affected SGs was discovered to be corroded to below minimum wall thickness (0.278") for the 1950 psi design pressure of the AFW System. The discovery was noted by PSEG during a planned excavation implementing their buried pipe inspection program. The lowest wall thickness measured in the affected piping was 0.077". PSEG plans on ~~excavating the Unit 2~~ buried piping to inspect the condition during the next Unit 2 outage scheduled for the spring of 2011. The affected Unit 1 piping was replaced. Although no leakage was evident as a result of the corrosion, the inspector questioned PSEG about whether the IWA-5244 periodic pressure tests had been conducted on this underground piping.

(2)

NEXT PAGE

10 CFR 50.55(a)(g)(4)(ii) requires licensees to follow the in-service requirements of the ASME Code, Section XI. Paragraph IWA-5244 of Section XI requires licensees to perform system pressure tests on buried components to demonstrate the structural integrity of the tested piping. The system pressure test required by IWA-5244 is considered to be an inservice inspection and is part of Section XI. Section XI and IWA-5244 do not specify other non-destructive examinations (NDE) on buried components to demonstrate structural integrity other than a flow test if the system pressure test cannot be performed. PSEG had not performed the required tests for Unit 1 since 1988. ~~Also~~ PSEG had not performed the required tests for Unit 2 since 2001. Thus, PSEG did not perform the inservice inspection provided by the ASME Code, Section XI, intended to demonstrate the structural integrity of this safety related buried piping.

NEXT PAGE

PSEG was aware of the need to perform these required tests because PSEG sought relief, from the NRC, from the previous Code required pressure testing in 1988 for Unit 1 only. Relief was granted to PSEG, by the NRC, to perform an alternate flow test in 1991 for Unit 1. However, PSEG did not perform the proposed alternate flow tests for Unit 1 since 1988. ~~Also, PSEG did not request relief from the required tests or perform the~~

a

~~PSEG DETERMINED~~ MAINTAINED THAT THE BURIED PORTIONS OF AFW MAINTAINED STRUCTURAL INTEGRITY S

~~proposed alternate tests on the Unit 2 buried piping from 2001 to the present.~~ Thus, PSEG had ~~had~~ chance to foresee and correct this performance deficiency for both units but missed the opportunity at the time of processing this final results of the relief request. PSEG replaced the affected Unit 1 buried piping during the refueling outage in April/May 2010. The required pressure tests were successfully completed after the replacement of the Unit 1 buried piping. Because the AFW system functioned ~~as required~~ during the plant shutdown prior to the start of 1R20 (April 2010), ~~the system did not loose operability.~~ ~~AND BASED ON THE~~ FINITE ELEMENT ANALYSIS OF THE EXCAVATED PORTIONS OF PIPING

~~For Unit 2~~, PSEG completed an Operability Determination and a Risk Assessment for continued operation until the next scheduled refueling outage, scheduled for spring 2011. These evaluations determined that the condition was acceptable for continued operation until spring 2011. At present, it was not feasible to conduct the system pressure test or alternate flow test for operating conditions and no degradation has been discovered on the Unit 2, buried AFW piping.

DID ~~NOT~~

Revue

Analysis. Because buried piping is not accessible for visual or volumetric non-destructive examination, the ASME Code, Section XI, paragraph IWA-5244 specifies a periodic pressure test as a method of demonstrating that structural integrity exists in buried components including piping. PSEG's ~~failure~~ to perform the pressure test on this safety related buried piping is a performance deficiency for each Salem Unit. For each unit, this performance deficiency was reasonably within the licensee's ability to foresee because PSEG sought Code relief from the pressure test in 1988 for Unit 1, and the deficiency could have been corrected and should have been prevented for both units. PSEG did not perform the inservice inspection (IWA-5244, pressure test), intended to demonstrate the structural integrity of this safety related buried piping.

ADDITIONALLY PSEG CONDUCTED A FINITE ELEMENT ANALYSIS USING AS FOUND UT READINGS OF EXCAVATED PORTIONS OF THE PIPING.

This performance deficiency is a violation of regulatory requirements of 10 CFR 50.55a(g)(4) and the ASME Code, Section XI, paragraph IWA-5244 for Salem Unit 1. The inspector determined that the performance deficiency (failure to perform the pressure testing) was more than minor, for the Unit 1 conditions, because, if left uncorrected, it would have resulted in a more significant condition. That is, in light of the as-found degraded conditions of the coating and the piping discovered during excavation in Unit 1, an undetected failure of the piping would have resulted due to further continued, undetected corrosion, and continued pipe wall degradation eventually resulting in the loss of structural integrity without system pressure testing.

For Unit 2, the performance deficiency is minor because PSEG has not identified corrosion on the Unit 2 buried AFW piping. PSEG did not perform the required pressure tests of the buried piping to the #22 SG and #24 SG for Unit 2 for the 1st period (5/19/01 to 6/3/04) and 2nd period (6/24/04 to 5/20/08) of the 3rd In Service Inspection Interval. Accordingly and in accordance with IMC 0612 section 0612-11, this failure to comply with the above noted ASME code requirements for Unit 2 constitutes a violation of minor significance that is not subject to enforcement action in accordance with the NRC's enforcement policy.

For Unit 1, the inspector screened this performance deficiency using IMC 0609, Attachment 0609.04, "Phase 1 Initial Screening and Characterization of Findings." This finding impacts the mitigating systems cornerstone by adversely affecting the secondary, did not

The inspector determined that a Cross Cutting Aspect did not exist because the issue was not indicative of current performance because the condition existed since 1991, more than 3 years ago. Specifically, the failure to perform these pressure tests began in 1988 when PSEG requested relief from the requirement and ~~neglected to~~ incorporate the actions of the relief into the plant inservice inspection program when it was granted in 1991.

Enforcement. 10 CFR 50.55a(g)(4) states, in part: "Throughout the service life of a boiling or pressurized water-cooled nuclear power facility, components ...which are classified as ASME Code Class 1, Class 2 and Class 3 must meet the requirements, set forth in Section XI of editions of the ASME Boiler and Pressure Vessel Code". Paragraph IWA-5244, Buried Components, of Section XI says, in part,

> "(b) For buried components where a VT-2 visual examination cannot be performed , the examination requirement is satisfied by the following: (1) The system pressure test for buried components that are isolable by means of valves shall consist of a test that determines the rate of pressure loss. Alternatively, the test may determine ~~the change in~~ flow between the ends of the buried components. "

SPECIFICALLY,

Contrary to these requirements, PSEG did not perform the required pressure tests of the buried AFW piping to the #12 SG and #14 SG at Salem Unit 1 during the 2nd In Service Inspection Interval (2/27/88 to 5/19/01) and during the 1st (5/19/01 to 6/3/04) and 2nd (6/24/04 to 5/20/08) periods of the 3rd In Service Inspection Interval (5/19/01 to 5/19/11). ~~Consequently~~ from 2/27/88 to April 2010 the required pressure tests were not performed to demonstrate structural integrity on the affected buried Unit 1 AFW piping.

Because PSEG entered this condition for Salem Unit 1 into the corrective action process (Notification 20459686) and because it is of very low safety significance (Green), it is being treated as a non-cited violation consistent with Section VI.A.1 of the NRC Enforcement Policy. **NCV 50-272/2010003-??**

4OA2 Identification and Resolution of Problems (71152)

a. Inspection Scope

The inspectors reviewed a sample of corrective action reports (notifications), listed in Attachment 2 which involved in-service inspection related issues, to ensure that issues are being promptly identified, reported and resolved.

b. Findings

No findings of significance were identified.

Burritt, Arthur

From: Conte, Richard
Sent: Friday, May 07, 2010 4:10 PM
To: Burritt, Arthur; Ennis, Rick; Lupold, Timothy; Manoly, Kamal; OHara, Timothy; Patnaik, Prakash; Schroeder, Daniel; Schulten, Carl; Tsao, John
Cc: DeFrancisco, Anne; Balian, Harry; Bowman, Eric; Brown, Michael; Cahill, Christopher; Chernoff, Harold; Gardocki, Stanley; Gray, Harold; Hardies, Robert; Hoffman, Keith; Holston, William; Modes, Michael; Pelton, David; Robinson, Jay; Sanders, Carleen; Schmidt, Wayne; Thorp, John; Taylor, Robert
Subject: Salem Unit 2/1 AFW Pipe Degradation
Attachments: SL1 AFW Degradation Telecon of 04-28-2010.doc

We need another Conference to discuss developments since the April 28 telecon. See attached file for summary and actions along with residual actions. I am looking for Monday pm since Region I is in a counterparts meeting for Tues thru Thursday, can do Thursday pm. I am off Friday.

Some of you may have gotten emails today on entering the TS LCO related to structural integrity and how well it does or does not mesh with rule and code per 10 CFR 50.55a. These residual issues are right after the problem summary in the attached file. During the call we can summarize discuss point and counterpoint.

1. Does the licensee need a code relief request to cover:
   a. Time from now to the outage in 2011 IAW 10 CFR 50.55a (g) (5) (iii) as impractical to perform?
   b. Cover the first two periods of the current 10 year interval IAW 10 CFR 50.55a (g) (5) (iii) impractical to perform (they could have done it during there outages) or (iv), post ISI interval review?

2. Should staff inform PSEG they are violating TS LCO on structural integrity regardless of how ambiguously it is written. Do we really understand the consequence of this action.

3. For this case, do the rule/code requirements stand alone and what are they – evaluation of suitability for service in light of not doing the pressure drop test for Unit 2.

I hope to have a conference bridge all afternoon. Hopefully key players as noted in addressee list can communicate their availabiltiy in the pm preferrably 300pm but I am open to 1 2 or 3pm. If you want to be considered as a key player let me know.

CS9106110096

UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555

March 11, 1991

MANAGER - LICENSING and REGULATION
MAR 15 '91
NUCLEAR LICENSING
LICENSING
MGR. LIC. MGR.
CONSTRUCTION PERMITS
RECORDS MANAGEMENT
SENIOR SECRETARY
ALL PERSONNEL
Reply by
Return

Docket No. 50-272

Mr. Steven E. Miltenberger
Vice President and Chief Nuclear Officer
Public Service Electric and Gas Company
Post Office Box 236
Hancocks Bridge, New Jersey 08038

Dear Mr. Miltenberger:

SUBJECT: FIRST TEN-YEAR INSPECTION INTERVAL, INSERVICE INSPECTION PROGRAM RELIEF REQUEST, SALEM NUCLEAR GENERATING STATION, UNIT 1 (TAC NOS. 66013 AND 71101)

By letters dated July 17, 1987, June 6, 1988, and November 28, 1988, Public Service Electric and Gas Company (licensee) submitted to the NRC requests for relief from the requirements of Section XI of the ASME Code (1974 Edition through Summer 1975 Addenda) for the First Ten-Year Interval Inservice Inspection Program Plan for the Salem Nuclear Generating Station, Unit 1.

The Materials and Chemical Engineering Branch, Division of Engineering Technology, has reviewed and evaluated the requests for relief from some Section XI requirements that the licensee determined to be impractical to perform at the facility. We have determined that these requirements of Section XI are impractical to perform at the facility and we have granted, pursuant to 10 CFR 50.55a(g)(6)(i), the relief requested and authorized alternatives proposed where the necessary findings could be made. This relief is authorized by law and will not endanger life or property or the common defense and security and is otherwise in the public interest giving due consideration to the burden upon the licensee that could result if the requirements were imposed on the facility. An evaluation of the reliefs and the bases for granting the requests are contained in the enclosed Safety Evaluation (SE). It should be noted that the second Ten-Year Inservice Inspection Interval and associated requests for relief were approved in a letter dated April 17, 1990. This current approval of relief for the First Ten-Year Interval is for record purposes only in that the second Ten-Year Interval is the one in use.

We conclude that the relief from the ASME Code, Section XI (1974), requirements that were impractical to perform and as evaluated in the enclosed SE is granted. Granting this relief will not significantly reduce the assurance of the plant's structural integrity or safety.

Sincerely,

Walter R. Butler

Walter R. Butler, Director
Project Directorate I-2
Division of Reactor Projects - I/II
Office of Nuclear Reactor Regulation

Enclosure:
Safety Evaluation

cc w/enclosure:
See next page

Mr. Steven E. Miltenberger
Public Service Electric & Gas Company   Salem Nuclear Generating Station

cc:

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UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555

SAFETY EVALUATION BY THE OFFICE OF NUCLEAR REACTOR REGULATION

OF PUBLIC SERVICE ELECTRIC AND GAS COMPANY'S REQUEST FOR RELIEF FROM ASME

SECTION XI NDE AND HYDROSTATIC PRESSURE TESTING REQUIREMENTS

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

SALEM GENERATING STATION, UNIT 1

DOCKET NO. 50-272

1.0 INTRODUCTION

Pursuant to 10 CFR 50.55a(g) it is required that examinations and tests of nuclear power facility piping and components to be performed in accordance with the requirements of the applicable ASME Section XI Code edition and addenda. If it is impractical to meet the requirements, the licensee of the facility is required to notify the Commission and submit information in support of the determination that a requirement is impractical to perform.

By letters dated July 17, 1987, June 6, 1988, and November 28, 1988, Public Service Electric and Gas Company (PSE&G) (licensee) submitted requests for relief from certain ASME Section XI requirements for the first ten-year interval. The licensee's First Ten-Year ISI program is based on ASME Section XI, 1974 Edition through Summer 1975 Addenda (1974 Code). In addition, the licensee's Second Ten-Year ISI Program was approved by NRC letter dated April 17, 1990 and is based on the requirements of the 1983 Edition through Summer 1983 Addenda of Section XI of the ASME Code (1983 Code).

Furthermore, in some cases, the licensee's request for relief dated July 17, 1987 from the requirements of the governing 1974 Code to perform certain inspections are no longer required because the requirements either have been deleted or revised in the 1983 Code. The licensee's requests for relief from certain ASME Section XI requirements for the first ten-year interval are evaluated herein pursuant to 10 CFR 50.55a(g)(6)(i) to determine if the necessary findings can be made to grant the request.

2.0 EVALUATION

A. RELIEF REQUEST (RR) NUMBER 1 - RELIEF FROM VT EXAMINATIONS OF CLASS 1 INTERIOR CLAD SURFACES OF VESSELS OTHER THAN REACTOR VESSELS (07/17/87 LTR., TAC NO. 66013)

COMPONENT IDENTIFICATION

System:	Various
Component Description:	Class 1 Pressurizer, Heat Exchanger, and Steam Generator Cladding

ASME CODE SECTION XI FIRST INTERVAL INSPECTION REQUIREMENTS

1974 Edition through Summer 1975 Addenda Class 1, Category B-I-2, Item No. B2.9 (Pressurizer) and Category B-I-2, Item No. B3.8 (Heat Exchanger and Steam Generator) requires visual examination.

RELIEF REQUESTED

Relief is requested from 100% visual examination of patch areas of cladding on the Pressurizer, Heat Exchangers and Steam Generators.

LICENSEE'S BASIS FOR RELIEF

The ASME Code has recognized that cladding is not part of the pressure retaining boundary, nor is it relied upon for structural integrity. Also, visual examinations performed on cladding patches of the Salem Reactor Vessel Head and on the No. 12 Steam Generator have not identified any unacceptable conditions.

These examination requirements have been deleted from the later editions of the Code which have been approved by the NRC and incorporated into 10 CFR 50.55a.

Recognizing this deletion and intent of the ASME Section XI examinations to provide monitoring of component degradation over the plant's service interval, it is our position that the radiation exposure and costs associated with the cladding visual examinations are not commensurate with the increase in safety realized.* Therefore, PSE&G requests relief from performing these examinations.

* See Radiation Considerations Section below.

ALTERNATIVE EXAMINATION

No additional examinations in these categories since later editions and addenda of ASME Section XI approved by the NRC and incorporated into 10 CFR 50.55a no longer require cladding examinations.

PLANT QUALITY & SAFETY

Other examinations performed, together with system pressure tests (as applicable) provide an acceptable level of assurance of system integrity and plant safety.

RADIATION CONSIDERATIONS

The Man-hour/exposure estimate for removal of one steam generator manway:

- 40 man-hours
- 4 man-rem exposure

STAFF EVALUATION AND CONCLUSIONS

The Code requirements to visually examine, during each inspection interval, 100% of the patch areas for Pressurizer, Heat Exchanger and Steam Generator Cladding is impractical because of the radiation exposure of 4 man-rem for the removal of one steam generator manway. In addition, the 1974 Edition through Summer 1975 Addenda, Item No. B2.9, Category B-I-2 and Item No. B3.8, Category B-I-2 requirements have been deleted from later editions of the Code. Furthermore, the later editions of the Code have been approved by NRC and incorporated into 10 CFR 50.55a. Therefore, the staff has determined, pursuant to 10 CFR 50.55a(g)(4)(iv) (the license for full power was issued on December 1, 1976) the licensee may use the later Code editions approved in 10 CFR 50.55a(b). Visual inspection of the cladding for the Pressurizer, Heat Exchanges and Steam Generators is no longer required by later editions of the Code, compliance with the specific ASME requirement would result in hardship due to the high radiation exposure and the visual inspection would not contribute to quality and safety operation of the plant.

B. RELIEF REQUEST (RR) NUMBER 2 ASME SECTION XI RR FROM CLASS 1 PUMP CASING VISUAL EXAMINATIONS (07/17/87 LTR., TAC NO. 66013)

COMPONENT IDENTIFICATION

System:	Reactor Coolant System
Component Description:	Reactor Coolant Pump Casings

ASME CODE SECTION FIRST INTERVAL INSPECTION REQUIREMENTS

1974 Edition through Summer 1975 Addenda, Item No. B5.7, Category B-L-2 requires that one pump in each of the group of pumps performing similar functions in the system shall be (visually) examined during each inspection interval. This examination may be performed on the same pump selected for the Category B-L-1 (volumetric) examination.

RELIEF REQUESTED

Relief is requested from performing visual examination of the pump internal pressure retaining surfaces.

LICENSEE'S BASIS FOR RELIEF

Currently there are no plans for disassembly of any of the Reactor Coolant Pump Casings for maintenance. NRC Safety Evaluation dated August 12, 1981 granted relief from the volumetric requirements of the Code Item B5.6 Category B-L-1 such that only surface examination on the external surface of the weld is required to be performed. As such, PSE&G has been evaluating new techniques for volumetrically examining the pump casing welds. Such a technique exists using the Miniature Linear Accelerator (MINAC) which was built under an EPRI sponsored program. This equipment has been made available to other utilities, and currently constitutes the only method available for the volumetric examination of reactor coolant pump casing welds. This examination was performed at Ginna in the spring of 1981, at Point Beach Unit 1 in the fall of 1981, at Turkey Point Unit 3 early in 1982, and at H.B. Robinson Unit 2 later in 1982. No problems with welds were found at any of the sites.

The successful performance of this volumetric examination using the MINAC demonstrates that the method is capable of satisfying ASME Section XI examination requirements. Based on the following information, however, PSE&G does not plan to use this technique.

The volumetric examination method is radiographic and is performed by placing the MINAC inside the pump casing and placing film on the outside of the pump. To perform the examination, the pump must be completely disassembled. This disassembly is far beyond that performed for normal maintenance. In addition, insulation must be removed from the exterior of the pump casing.

The performance of the examination has shown that there is a relatively high radiation exposure associated with it. The total exposure associated with insulation removal, disassembly, examination, and reassembly of the pump has averaged about 40 man-rem.

The pumps casing examinations are also not justified from a cost/benefit perspective. The pump disassembly, examination and reassembly is estimated to cost $750,000.

Based on the preceding factors, PSE&G does not consider it justifiable to disassemble these pumps solely for the purpose of performing these examinations. Therefore, relief is required from performing visual examination of the pump internal pressure retaining surfaces.

ALTERNATE EXAMINATION

Visual examination will be performed on the external pressure boundary surfaces of the pump casing weld in conjunction with the surface examinations performed.

PLANT QUALITY & SAFETY

Alternative examinations performed, together with system pressure tests (as applicable) provide an acceptable level of assurance of system integrity and plant safety.

RADIATION CONSIDERATIONS

The total exposure associated with insulation removal, disassembly, examination, and reassembly of the pump has averaged about 40 man-rem.

STAFF EVALUATION AND CONCLUSIONS

The requirement to visually inspect the internal pressure boundary surfaces of the Reactor Coolant Pumps (RCP) is impractical because of the relatively high radiation exposure from insulation removal, disassembly, examination, and reassembly of the pumps. In addition, to disassemble the pumps for the sole purpose to inspect the internal pressure boundary surfaces may be counterproductive due to the possibility of causing damage to the pump internals during disassembly and/or reassembly of the pumps. The staff has determined that the alternative inspection proposed by the licensee will provide adequate assurance of the structural integrity of the Reactor Coolant Pump's casings with the exception that the licensee perform the required Code inspections when a RCP is completely disassembled for a scheduled maintenance activity. Pursuant to 10 CFR 50.55a(g)(6)(i), we conclude that relief from the ASME Boiler and Pressure Code requirement may be granted as requested by the licensee provided the licensee performs the required Code inspections when a RCP is completely disassembled for a scheduled maintenance activity.

C. RELIEF REQUEST NUMBER 3 - REQUEST FROM CLASS 1 VALVE VT EXAMINATIONS (07/17/87 LTR., TAC NO. 66013)

COMPONENT IDENTIFICATION

System: Various
Component Description: Valve Bodies

ASME CODE SECTION XI FIRST INTERVAL INSPECTION REQUIREMENTS

1974 Edition through Summer 1975 Addenda, Item No. B6.7, Category B-M requires that visual examination of the internal pressure boundary surfaces, on valves exceeding 4 inches of the same constructional design, e.g., globe, or check valve, manufacturing method and manufacturer that performs similar functions in the system shall be examined during each inspection interval. The examination may be performed at or near the end of the inspection interval.

RELIEF REQUESTED

Relief is requested from performing a visual examination of the interior surface of valves 4 inch nominal pipe size and larger.

LICENSEE'S BASIS FOR RELIEF

Disassembly of a valve which has been functioning within acceptable parameters for the sole purpose of examination is contrary to good maintenance practices since the likelihood of failure may be increased. These components are subjected to an alternate form of performance and/or leakage monitoring such as inservice valve testing, or primary coolant system leak detection. Valves in this category are constructed of cast austenitic stainless, which have been identified as unlikely to experience failure by cracking. Finally, considering the uncertain benefit involved, it is difficult to justify the additional radiation exposure which would be incurred as a result of the disassembly, examination, and reassembly of the valve.

PSE&G believes that performing a visual examination of the interior of one valve in a group of similar valves within the Class 1 pressure boundary at Salem Generating Station Unit 1 during the first Ten Year Inservice Inspection Interval does not provide an increase in safety above that provided by routine inservice valve testing and pressure testing required by ASME Section XI. Therefore, the costs and radiation exposure associated with this examination also are not justifiable.*

PSE&G has performed visual examinations on internal surfaces of all but (2) groups of valves identified at Salem. One group is associated with the 1RH1, 1RH2 valves and the other with 11 through 14SJ56 valves.

* See Radiation Considerations Section below.

ALTERNATE EXAMINATION

In lieu of examination of each similar valve's interior on lines 4 inch nominal pipe size and large during the interval, PSE&G proposes to examine only those valves in this category which are disassembled during the remainder of the interval for maintenance purposes.

PLANT QUALITY & SAFETY

The examinations as performed, together with the completed leakage, hydrostatic and other pressure tests (as required), provide an acceptable level of assurance of integrity of the valve body pressure retaining boundary.

RADIATION CONSIDERATIONS

Man-hour/exposure estimate for disassembly of 1RH1 valve and reassembly:

- 145 man-hours
- 4 man-rem exposure

STAFF EVALUATION AND CONCLUSIONS

The Code requirement to visually examine the internal pressure boundary surfaces, on valves exceeding 4 inches nominal pipe size is impractical because of the radiation exposure associated with the disassembly, examination, and reassembly of the valves. In addition, the disassembly and reassembly of the valves could be counterproductive due to the possibility of causing damage to the internals of the valve. The staff has determined that the alternative inspections will provide adequate assurance of the structural integrity of the valve's internal pressure boundary surfaces. Pursuant to 10 CFR 50.55a(g)(6)(i), we conclude that relief from the ASME Boiler and Pressure Code requirement may be granted as requested by the licensee.

D. RELIEF REQUEST NUMBER 4 - RELIEF FROM VOLUMETRIC EXAMINATION OF CLASS 1 INTEGRALLY-WELDED EXTERNAL SUPPORT ATTACHMENTS (07/17/87 LTR., TAC NO. 66013)

COMPONENT IDENTIFICATION

System: Various
Component Description: Integrally-Welded External Support Attachments

ASME CODE SECTION XI FIRST INTERVAL INSPECTION REQUIREMENTS

1974 Edition through Summer 1975 addenda, Item No. B4.9, Category B-K-1 requires that volumetric examination of integrally-welded external support attachments. This includes the welds to the pressure retaining boundary and the base metal beneath the weld zone and along the support attachment member for a distance of two support thicknesses.

RELIEF REQUESTED

Relief from volumetric examination of integrally-welded external support attachments.

LICENSEE'S BASIS FOR RELIEF

Due to geometric configuration, full coverage has not been obtained using standard UT techniques. Coverage typically equals 90% of the total percentage required by the 1974 Edition of the Code.

In the 1983 Edition of Section XI, examination requirements for B-K-1 welds have been changed from volumetric to surface. This edition has been approved by the NRC and incorporated into 10 CFR 50.55a.

ALTERNATE EXAMINATION

Surface examination as allowed by ASME Section XI, 1983 Edition 1983 Summer Addenda, Item B10.10, Category B-K-9.

PLANT QUALITY AND SAFETY

The required system operational, leakage, hydrostatic and other pressure tests (as applicable), provide an acceptable level of assurance of the pressure retaining boundary integrity where the integrally-welded external support attaches.

RADIATION CONSIDERATIONS

None

STAFF EVALUATION AND CONCLUSIONS

The Code requirements for volumetric examination of integrally-welded external support attachments is impractical because of the geometric configurations and full coverage has not been obtained using standard UT techniques. Furthermore, ASME Code, 1983 Edition of Section XI 1983 Summer Addenda, examination requirements for B-K-1 have been changed from volumetric to surface. The staff has determined that the alternative inspection (surface) proposed by the licensee will provide adequate assurance of the structural integrity of the external support welds to the pressure retaining boundary and the base metal beneath the weld zone and along the support attachment member for a distance of two support thicknesses. In addition, the piping system would have to be redesigned in order to perform the required Code inspections thus, imposing a burden on the licensee. Pursuant to 10 CFR 50.55a(g)(6)(i), we conclude that relief from the ASME Boiler and Pressure Code requirement may be granted as requested by the licensee.

E. RELIEF REQUEST NUMBER 5 - RELIEF FROM VOLUMETRIC EXAMINATION OF CLASS 1 BRANCH CONNECTION WELDS EXCEEDING SIX (6) INCHES IN DIAMETER (07/17/87 LTR., TAC NO. 66013)

COMPONENT IDENTIFICATION

System: Various
Component Description: Class 1 Branch connection welds exceeding six inches in diameter.

ASME CODE SECTION XI FIRST INTERVAL INSPECTION REQUIREMENTS

1974 Edition through Summer 1975 Addenda, Item No. 4.6, Category B-J requires volumetric examination of pipe branch connections. This shall include the weld metal, the base metal for one pipe wall thickness beyond the edge of the weld on the pipe run and at least two (2) inches of base metal along the branch run.

RELIEF REQUESTED

Relief is requested from volumetric examination of pipe branch connections.

LICENSEE'S BASIS FOR RELIEF

The geometric configuration makes the complete coverage of the volume specified in the 1974 Edition of the Code prohibitively difficult. Typical coverage is 90% of the required volume.

The volume specified in the 1983 Edition of the Code has been reduced to the lower 1/3 and supplemented with a surface examination. This edition of the Code has been approved by the NRC and incorporated into 10 CFR 50.55a.

ALTERNATE EXAMINATION

Volumetric and surface examinations of branch connection welds exceeding six (6) inches as required by ASME Section XI 1983 Edition, 1983 Summer Addenda. Item B9.30 Category B-J.

PLANT QUALITY & SAFETY

The required system operational, leakage, hydrostatic and other pressure tests (as applicable), provide an acceptable level of assurance of structural and system integrity for the pipe branch connections.

RADIATION CONSIDERATIONS

None

STAFF EVALUATION AND CONCLUSIONS

The Code requirement for Volumetric examinations of pipe branch connections is impractical to perform because the geometric configuration precludes the complete coverage of the volume specified in the 1974 Edition of the Code. The staff has determined that the alternative inspections proposed by the licensee will provide adequate assurance of the structural integrity of the Class 1 branch connection welds exceeding six inches in diameter. In addition, the piping system would have to be redesigned in order to perform the required Code inspections thus, imposing a burden on the licensee. Pursuant to 10 CFR 50.55a(g)(6)(i), we conclude that relief from the ASME Boiler and Pressure Code requirement may be granted as requested by the licensee.

F. RELIEF REQUEST FROM 10 YEAR HYDROSTATIC TEST REQUIREMENTS FOR BURIED PIPING IN THE AUXILIARY FEEDWATER SYSTEM (06/06/88 AND 11/28/88 LTRS., TAC NO. 71101)

COMPONENT IDENTIFICATION

System: Auxiliary Feed Water
Component Description: Auxiliary Feedwater System Buried Piping

ASME CODE SECTION XI FIRST INTERVAL INSPECTION REQUIREMENTS

1974 Edition through Summer 1975 Addenda, Article IWD - 2600(b) requires in the case of buried components (e.g., underground piping), valves shall be provided to permit isolation of the buried portions of piping for the purpose of conducting a system pressure test in lieu of the visual examination. A loss of system pressure during the test shall constitute evidence of component leakage.

RELIEF REQUESTED

Relief is requested from conducting a system pressure test by using valves to isolate buried portions of piping.

LICENSEE'S BASIS FOR RELIEF

1. The buried piping was initially tested by a pressure drop test by using boundary valves as prescribed in the Code. The pressure drop test failed because of excessive leakage through the test boundary. The leakage was suspected to be past the 12AF23 and 14AF23 valves. In order to substantiate this suspected leakage path, the alternate test method described below was used. Relief is being requested as the Code does not provide for an alternate method of testing inaccessible pipe.

2. This matter was considered unresolved (Item 272/87-32-01) in the routine Resident Safety Inspection performed between November 3, 1987 to November 30, 1987 (NRC Combined Inspection Report 50-272/87-32 and 50-311/87-33). The inspector found the alternative test method to be a reasonable alternative to the pressure drop test since the boundary valves could not be made leak tight. The inspector also requested that a relief request be submitted to acquire a formal approval for the use of the alternate test method.

LICENSEE'S ALTERNATIVE EXAMINATION

PSE&G conducted a pressure test of buried piping between valves 12AF23, 12AF21 and 12AF86 for Steam Generator #12 and 14AF23, 14AF21 and 14AF86 for Steam Generator #14 using the following alternate test method. The header pressure was maintained with the hydrostatic test pump. While the pressure was maintained, and for the duration of the test, both the volume of water used by the pump and that collected downstream of the leaking test boundary valves 12AF23 and 14AF23 were measured. The two measured volumes were then compared to provide assurance that the inaccessible portion of the pipe had no identified leakage. The buried pipe in each case was approximately 190 feet in length.

PLANT QUALITY & SAFETY

The required system operational, leakage, hydrostatic and other pressure tests (as applicable), provide an acceptable level of assurance of structural and system integrity for the buried piping in the auxiliary feedwater system.

RADIATION CONSIDERATIONS

None

DIFFERENT THAN WE HEARD RECENTLY

STAFF EVALUATION AND CONCLUSIONS

The Code requirement to hydrostatically test underground piping by using valves to isolate the system is impractical because the valves that are used for isolation were not designed to be leak tight. During hydro testing the valves leaked, causing the system to fail the required Code testing. The staff has determined that the alternative test proposed by the licensee will provide adequate assurance of the structural integrity of the buried piping for the Auxiliary Feedwater System. In addition, the piping system would have to be redesigned in order to perform the required Code inspections thus, imposing a burden on the licensee. Pursuant to 10 CFR 50.55a(g)(6)(i), we conclude that relief from the ASME Boiler and Pressure Code requirement may be granted as requested by the licensee.

G. RELIEF REQUEST NUMBER 1 - RELIEF REQUEST FROM 10 YEAR HYDROSTATIC TEST REQUIREMENTS FOR CLASS 1 PIPING (07/17/87 LTR., TAC NO. 66013)

COMPONENT IDENTIFICATION

System:	Various
Component Description:	Ferritic Vessels with the Tested Systems

ASME CODE XI FIRST INTERVAL INSPECTION REQUIREMENTS

1974 Edition through Summer 1975 Addenda, Article IWB 5222(b) states the test pressure may be reduced in accordance with the following table when system hydrostatic testing is required to be conducted at temperatures above 100° F in order to meet the fracture toughness criteria applicable to ferritic materials of which the system components are constructed:

TEST TEMPERATURE	TEST PRESSURE
100° F	1.10 Po
200° F	1.08 Po
300° F	1.06 Po
400° F	1.04 Po
500° F	1.02 Po

RELIEF REQUESTED

Relief is requested to test austenitic stainless steel portions of the Nuclear Class 1 systems that cannot be isolated from the portions that contain ferritic materials to the requirements of Article IWB 5222(b).

LICENSEE'S BASIS FOR REQUEST

In order to protect the structural integrity of the ferritic vessels within these systems, non-isolable portions made of austenitic stainless steel should not be tested at a higher pressure and temperature than required by

IWB 5222(b). These requirements have been incorporated in the 1983 Edition of Section XI, which has been approved by the NRC and incorporated into 10 CFR 50.55a.

ALTERNATE EXAMINATION

Austenitic stainless steel portions of the Nuclear Class 1 systems that cannot be isolated from the portions that contain ferritic materials, such as the Reactor Vessel, shall be subject to the same reduced pressure and temperatures requirements as specified in IWB 5222(b) above.

PLANT QUALITY & SAFETY

The required system operational, leakage, hydrostatic and other pressure tests (as applicable), provide an acceptable assurance of structural and system integrity for the austenitic stainless steel portions of the Nuclear Class 1 systems that cannot be isolated from the portions that contain ferritic materials.

RADIATION CONSIDERATIONS

None

STAFF EVALUATION AND CONCLUSIONS

The Code requirement to hydrostatically test austenitic stainless steel portions of Class 1 systems that can not be isolated from the portions that contain ferritic materials is a hardship for the licensee to perform. The piping system would have to be completely redesigned in order to perform the Code required testing. Furthermore, the 1974 edition of the Code allows reduced test pressure for components of ferritic material and later editions of the Code permit the testing of the Reactor Coolant System at reduced pressures as the temperature is increased. Pursuant to 10 CFR 50.55a(g)(6)(i), we conclude that the licensee's alternative to the applicable ASME Boiler and Pressure Code requirement may be granted as requested.

H. RELIEF REQUEST NO. 2 - RELIEF REQUEST FROM 10 YEAR HYDROSTATIC TEST REQUIREMENTS FOR 3/4 INCH NUCLEAR CLASS 2 PIPING (07/17/87 LTR. TAC NO. 66013)

COMPONENT IDENTIFICATION

System:	Residual Heat Removal and Safety Injection
Component Description:	3/4 inch Class 2 Piping

ASME CODE SECTION XI FIRST INTERVAL INSPECTION REQUIREMENTS

1974 Edition through Summer 1975 Addenda, Article IWB-5200(a)[Sic] (licensee's 07/17/87 LTR should have reference Article IWC-5220(a) for Class 2 piping) requires that the system hydrostatic test pressure shall be at least 1.25 times the system design pressure (Pd) and conducted at a test temperature not less than 100° F except as may be required to meet the test temperature requirements of IWA-5320.

RELIEF REQUESTED

Relief is requested from the Code requirement that system hydrostatic test pressure shall be at least 1.25 times the system design pressure.

LICENSEE'S BASIS FOR RELIEF

The following Nuclear Class 2 portions of the Residual Heat (RH) Removal and Safety Injection (SJ) Systems cannot be tested at the required hydrostatic pressure. Pressurization at hydrostatic pressure would require cutting open the pressure boundary, and re-welding when the test is completed, which uses resources of man-hours (48 man-hours estimated per valve) and material and radiation exposure (0.1 man-rem exposure estimated per valve). Expending these resources is not justified when an acceptable level of safety can be achieved by performing the surface examinations and inservice pressure tests proposed in the alternate examinations below:

1. Approximately 4 feet of Stainless Steel RHR system piping between valves 1RH45 and 1RH33. These lines (shown in the sketch on Page 5 of Attachment 2 of PSE&G's letter dated July 17, 1987) cannot be pressurized to the required hydrostatic pressure due to:

   (a) Lines from the Demineralized Water System are welded to one side of the test boundary.

   (b) A check valve with a welded bonnet forms the other side of the test boundary.

   (c) There is no test connection within the test boundary.

   PSE&G requests that this portion of RHR piping be pressurized to the nominal operating pressure of the Demineralized Water System (80-90 PSI) in place of 565 PSI required by the Code.

2. Approximately 4 feet of Stainless Steel RHR system piping between valves 1RH46 and 1RH24. These lines (shown in the sketch on Page 6 of Attachment 2 of PSE&G's letter dated July 17, 1987) cannot be pressurized to the required hydrostatic pressure due to:

(a) Lines from the Demineralized Water System are welded to one side of the test boundary.

(b) A check valve with a welded bonnet forms the other side of the test boundary.

(c) There is no test connection within the test boundary.

3. Approximately 14 feet of Stainless Steel SJ system piping between valves 11SJ96 and 11SJ98. These lines (shown in the sketch on Page 7 of Attachment 2 of PSE&G's letter dated July 17, 1987) cannot be pressurized to the required hydrostatic pressure due to:

   (a) Lines from the Demineralized Water System are welded to one side of the test boundary.

   (b) A check valve with a welded bonnet forms the other side of the test boundary.

   (c) There is no test connection within the test boundary.

   PSE&G requests that this portion of RHR piping be pressurized to the nominal operating pressure of the Demineralized Water System (80-90 PSI) in place of 565 PSI required by Code.

4. Approximately 14 feet of Stainless Steel SJ system piping between valves 12SJ96 and 12SJ98. These lines (shown in the sketch on page 7 of Attachment 2 of PSE&G's letter dated July 17, 1987) cannot be pressurized to the required hydrostatic pressure due to:

   (a) Lines from the Demineralized Water System are welded to one side of the test boundary.

   (b) A check valve with a welded bonnet forms the other side of the test boundary.

   (c) There is no test connection within the test boundary.

   PSE&G requests that this portion of RHR piping be pressurized to the nominal operating pressure of the Demineralized Water System (80-90 PSI) in place of 565 PSI required by Code.

<u>ALTERNATIVE EXAMINATION</u>

PSE&G proposes to conduct surface examination of the welds and a test at nominal operating pressure for the following lines:

	Design Pressure	Alternate Test Pressure
3/4 inch line between valves 1RH45 and 1RH33	450 PSI	80 to 90 PSI
3/4 inch line between valves 1RH46 and 1RH24	600 PSI	80 to 90 PSI
3/4 inch line between valves 11SJ96 and 11SJ98	450 PSI	80 to 90 PSI
3/4 inch line between valves 12SJ96 and 12SJ98	450 PSI	80 to 90 PSI

PLANT QUALITY & SAFETY

The required system operational, leakage, hydrostatic and other pressure tests (as applicable), provide an acceptable level of assurance of Residual Heat Removal and Safety Injection System integrity.

RADIATION CONSIDERATIONS

Radiation exposure is estimated 0.1 man-rem per valve.

STAFF EVALUATION AND CONCLUSIONS

The code requirement to hydrostatically test portions of the Residual Heat Removal (RHR) and Safety Injection (SJ) Systems is impractical because of the system design. Pressurization at hydrostatic pressure would require cutting open the pressure boundary, and rewelding when the test was completed. Furthermore, there are no test connections within the test boundary and modifications would have to be made. The staff has determined that the alternative tests proposed by the licensee will provide adequate assurance of the structural integrity of the portion of the 3/4 inch RHR and SJ piping in which relief was requested. Pursuant to 10 CFR 50.55a(g)(6)(i), we conclude that relief from the ASME Boiler and Pressure Code requirement may be granted as requested by the licensee.

3.0 CONCLUSION

The staff has determined, with respect to the relief requested, that the requirements of the Code are impractical to perform and relief is granted on the conditions stated above pursuant to 10 CFR 50.55a(g)(6)(i). This relief is authorized by law and will not endanger life or property or the common defense and security and is otherwise in the public interest giving due consideration to the burden upon the licensee that could result if the requirements were imposed on the facility.

Principal Contributor: T. McLellan

Date: March 11, 1991

SALEM AFW PIPING

U.S.NRC

Protecting People and the Environment

Buried Piping

- Chairman Tasking Memo
- COM-SECY 09-0174
  - No Operability Issues
  - No Leaks Exceeding NRC regulatory limits
  - Current Codes and Regulations are Adequate
- Groundwater Task Force

Recent buried piping leaks precipitated Chairman tasking memo

•There have been several instances of degraded buried piping leaks causing inadvertent releases of radioactive material and petroleum product to the environment at nuclear power plants.

Some of these leaks have resulted in tritium groundwater contamination at several plants.

Some of these leaks occurred in safety-related piping.

•The Commission directed the agency to take a focused look at the adequacy of current regulations, codes, standards and industry initiatives related to management of degradation of buried pipe.

Staff evaluated regulations, codes, standards and industry practices

•10 CFR 50.55a, "Codes and Standards,"

•10 CFR 50.65, "Requirements for monitoring the effectiveness of maintenance at nuclear power plants,"

•10 CFR part 54.21(a), "Aging Management"

•ASME Code

•The staff concluded that: for all of the actual events related to buried piping degradation, safety systems have remained operable and there has not been a challenge to piping structural integrity; leaks from degraded buried piping containing radioactive or other hazardous material has not exceeded NRC regulatory limits; and current regulations and codes and standards are adequate to address degradation of buried piping. Concluded these areas to be acceptable for operating plants, Plants undergoing license renewal, and New plants.

Industry developed a Buried Piping Integrity Initiative

•Industry has created initiatives in the past that have ensured all licensees perform a set of actions

For example, Groundwater initiative, Materials Initiative (for dissimilar metal butt welds)

•The industry has developed an initiative to address buried piping. The initiative would make licensees adopt a graded approach and a predictive maintenance approach for leaks in buried piping.

•The staff will continue to participate in ASME and NACE committees to develop enhancements related to advancements in technology or application of buried piping.

•Increased emphasis on buried piping in the license renewal process and in reactor oversight process inspections.

•Continue to monitor and respond to developments in buried piping leaks

•In addition, the staff will evaluate the need for changes to NRC inspection activities related to licensee implementation of the Buried Piping Integrity Initiative.

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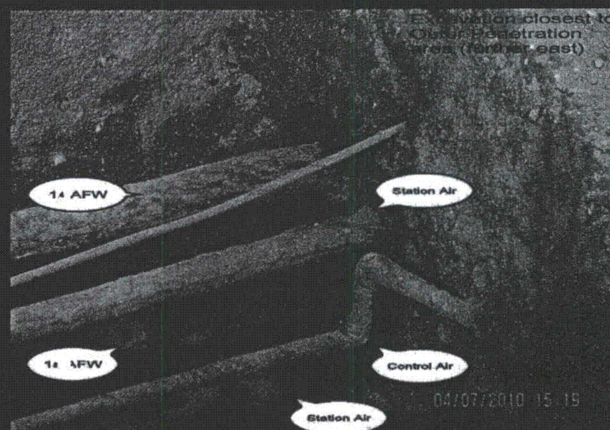

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Salem Excavation

U.S.NRC

Protecting People and the Environment

Salem Excavation

12:30 pm
5/12/10

866-205-5235
444338#

Kamal Manoly
301-415-2765

APPLICABILITY OF 4160 SINCE NO KNOWN DEGRADATION

(1) When will Unit 2 eval to meet IWA-4160 be completed?
NOT SURE 4160 4170 + 4180 APPLY
DO AGREE STRUCTURAL INTEGRITY NEEDS TO BE EVALUATED

(2) When will the Unit 1 EQ-ACE be completed?
JUNE 8

(3) When will the Unit 2 Operability Evaluation be finalized?
DONE, WILL PROVIDE IMMEDIATELY WILL PROVIDE THE REVISION

RCA complete 6/28

(4) In view of missed IWA-5244 tests/inspections are all past OAR's accurate?
YES PSEG IS CONSIDERING

(5) When will the inspectors open questions be answered?
UPDATE PROVIDED THIS DAY, "BALL BACK IN THE NRC's COURT"

(6) Does PSEG feel they are in any TS's due to the AFW piping on Unit 1 ~~or~~ Unit 2?
EVALUATING (presumption of operability?)

(6a) Does PSEG plan on ~~excavating U2 AFW in 2011?~~ Doing pres. test in 2011?

(7) PSEG requested relief from Sect. XI ~~&~~ hydro tests of AFW for Unit 1 in 1987 and 1988. (NRC ltr. dated 3/11/91) (page 9 & 10)
Was the same relief requested for Unit 2's first interval?

Was the alternate test performed on Unit 2?

Does PSEG have a copy of the completed Unit 1 test with data and signatures?