UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION I
2100 RENAISSANCE BOULEVARD, SUITE 100
KING OF PRUSSIA, PENNSYLVANIA 19406-2713

February 7, 2013

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

SUBJECT: SALEM NUCLEAR GENERATING STATION, UNIT NOS. 1 AND 2 – NRC INTEGRATED INSPECTION REPORT 05000272/2012005 AND 05000311/2012005

Dear Mr. Joyce:

On December 31, 2012, the U.S. Nuclear Regulatory Commission (NRC) completed an inspection at your Salem Nuclear Generating Station, Units 1 and 2. The enclosed inspection report documents the inspection results, which were discussed on January 10, 2013, with Mr. Wagner, Plant Manager of Salem, 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.

This report documents one NRC identified finding of very low safety significance (Green). This finding was determined to involve a violation of NRC requirements. However, because of the very low safety significance, and because it is entered into your corrective action program, the NRC is treating this finding as a non-cited violation (NCV), consistent with Section 2.3.2 of the NRC Enforcement Policy. If you contest the 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 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 for your disagreement, to the Regional Administrator, Region I, and the NRC Resident Inspector at Salem Nuclear Generating Station.

In accordance with 10 CFR 2.390 of the NRCs "Rules of Practice," a copy of this letter, its enclosure, and your response (if any) will be available electronically for public inspection in the

NRC Public Document Room or from the Publicly Available Records (PARS) component of the NRC's document system (ADAMS). ADAMS is accessible from the NRC website at http://www.nrc.gov/reading-rm/adams.html (the Public Electronic Reading Room).

Sincerely,

/RA/

Daniel L. Schroeder, Acting Chief
Reactor Projects Branch 3
Division of Reactor Projects

Docket Nos.: 50-272, 50-311
License Nos.: DPR-70, DPR-75

Enclosure: Inspection Report 05000272/2012005 and 05000311/2012005
w/Attachment: Supplementary Information

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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.:	05000272/2012005 and 05000311/2012005
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:	October 1, 2012, through December 31, 2012
Inspectors:	D. Schroeder, Senior Resident Inspector E. Bonney, Acting Senior Resident Inspector P. McKenna, Resident Inspector E. H. Gray, Senior Reactor Inspector J. Lilliendahl, Reactor Inspector R. Nimitz, Senior Health Physicist J. Schoppy, Senior Reactor Inspector D. Silk, Senior Operations Engineer J. Tomlinson, Operations Engineer
Approved By:	Daniel L. Schroeder, Acting Chief Reactor Projects Branch 3 Division of Reactor Projects

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SUMMARY OF FINDINGS

IR 05000272/2012005, 05000311/2012005; 10/01/2012 - 12/31/2012; Salem Nuclear Generating Station Unit Nos. 1 and 2; Fire Protection.

This report covered a three-month period of inspection by resident inspectors and announced inspections performed by regional inspectors. Inspectors identified one finding of very low safety significance (Green), which was a non-cited violation (NCV). The significance of most findings is indicated by their color (Green, White, Yellow, Red) using Inspection Manual Chapter (IMC) 0609, “Significance Determination Process” (SDP). The cross-cutting aspects for the findings were determined using IMC 0310, “Components Within 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: Mitigating Systems

- Green. The inspectors identified a Green NCV of the Unit 1 Operating License Condition 2.C because PSEG did not maintain an adequate CO2 inventory to ensure the operability of the installed deluge fire suppression system in accordance with the approved Fire Protection Plan. Specifically, the CO2 tank liquid level gage was not calibrated periodically, the gage was stuck at 72 percent level for a period of five months, and the tank lost pressure and was inoperable because it was empty on September 1, 2012. This issue was entered into PSEG’s corrective action program (CAP) as notification 20573227. PSEGs immediate corrective actions were to establish compensatory measures to restore fire protection system operability of the affected spaces on September 2, 2012, and then to complete replacement of the failed tank liquid level gage, leak check the tank and associated piping, and refill the liquid CO2 tank to restore the CO2 tank to operable status on October 23, 2012.

  The performance deficiency was determined to be more than minor because it affected the protection against external factors attribute of the Mitigating Systems cornerstone, in that it impacted automatic fire suppression capability, and affected the cornerstone objective of ensuring the availability of systems that respond to external events. The finding was evaluated under IMC 0609, Appendix F, “Fire Protection Significance Determination Process.” The conditional core damage probability was calculated utilizing SAPHIRE 8 for Salem Unit 1. Since the delta core damage frequency calculated in step 2.1.4 of Appendix F was less than the value specified in table 2.1.3, “Phase 2 Screening Step 1 Quantitative Screening Criteria,” the finding was determined to be of very low safety significance (Green). This finding has a cross-cutting aspect in the area of human performance, work control component. PSEG did not appropriately coordinate work activities by incorporating actions to plan work activities to support long-term equipment reliability by limiting safety system unavailability and reliance on manual actions. Specifically, a liquid level gage calibration preventive maintenance (PM) to maintain operability of the ten ton CO2 tank was created in accordance with vendor guidance in 2008, but the PM had not been implemented as of September 1, 2012. (H.3(b)) (Section 1R05)

REPORT DETAILS

Summary of Plant Status

Unit 1 began the inspection period at 100 percent power. On October 22, 2012, operators reduced power to 73 percent due to 500KV transmission line 5015 maintenance. Unit 1 returned to 100 percent power on October 24. On October 30, operators manually tripped Unit 1 due to a loss of four circulating water pumps caused by Hurricane Sandy river detritus. Unit 1 was synchronized to the grid on November 2, and returned to 100 percent power on November 4, 2012. On December 21, 2012, Unit 1 experienced a reactor trip due to a main turbine trip caused by a phase A main power transformer overexcitation relay actuating below its setpoint. Unit 1 was synchronized to the grid on December 22 and returned to 100 percent power on December 23, 2012. The unit remained at or near 100 percent power for the remainder of the inspection period.

Unit 2 began the inspection period at 100 percent power and operated at full power until October 15, 2012, when operators commenced a shutdown for a planned refueling and maintenance outage (2R19). The station reached Operational Condition 6 (refueling) on October 19. Following the completion of refueling and maintenance activities, operators commenced a reactor startup on November 18. On November 25, operators increased the unit to 91 percent power, but the unit tripped due to 24 steam generator low water level caused by a stuck main feedwater regulating valve. The feedwater regulating valve was repaired and Unit 2 was synchronized to the grid on November 26. Unit 2 returned to 100 percent power on November 29 and remained at or near 100 percent power for the remainder of the inspection period.

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, and Barrier Integrity

1R01 Adverse Weather Protection (71111.01 – 2 samples)

.1 Readiness for Impending Adverse Weather Conditions

a. Inspection Scope

The inspectors reviewed the actions completed by PSEG to prepare for Hurricane Sandy between October 25 and October 29, 2012. The inspectors evaluated PSEG's implementation of severe weather and fatigue management procedures and compensatory measures for extreme wind speed and rain. The inspectors verified that adequate operating staffing was onsite for the predicted conditions. The inspectors walked down risk significant structures, systems, and components (SSCs) to ensure that weather related conditions did not adversely impact SSC operability. In addition, the inspectors walked down the entire site to ensure that equipment and temporary structures were firmly secured so as to not create hazards during the predicted high winds. The inspectors performed detailed walkdowns of the service water (SW) intake structure, emergency diesel generators (EDGs), the main turbine and generators, and all outside equipment laydown areas. Documents reviewed for each section of this inspection report are listed in the Attachment.

b. Findings

No findings were identified.

.2 Readiness for Seasonal Extreme Weather Conditions

a. Inspection Scope

The inspectors performed a review of PSEG's readiness for the onset of seasonal cold temperatures. The review focused on the SW intake structure. The inspectors reviewed the Updated Final Safety Analysis Report (UFSAR), technical specifications (TSs), control room logs, and the CAP to determine what temperatures or other seasonal weather could challenge these systems, and to ensure PSEG personnel had adequately prepared for these challenges. The inspectors reviewed station procedures, including PSEG's seasonal weather preparation procedure and applicable operating procedures. The inspectors performed walkdowns of the selected system to ensure station personnel identified issues that could challenge the operability of the systems during cold weather conditions.

b. Findings

No findings were identified.

1R04 Equipment Alignment

.1 Partial System Walkdowns (71111.04Q – 4 samples)

a. Inspection Scope

The inspectors performed partial walkdowns of the following systems:

- Unit 1, EDGs in preparation for a single source of offsite power (SSOP) with 14 station power transformer out of service (OOS) on October 17, 2012
- Unit 2, 21 component cooling water (CCW) heat exchanger (HX) and 21 CCW pump after work restoration and securing the 22 CCHX on October 23, 2012
- Unit 2, 2A and 2C EDGs with 2B EDG OOS for maintenance on October 24, 2012
- Unit 1, SW system with the 13 SW pump OOS on December 6, 2012

The inspectors selected these systems based on their risk-significance relative to the reactor safety cornerstones at the time they were inspected. The inspectors reviewed applicable operating procedures, system diagrams, the UFSAR, TSs, work orders, condition reports, and the impact of ongoing work activities on redundant trains of equipment in order to identify conditions that could have impacted system performance of their intended safety functions. The inspectors also performed field walkdowns of accessible portions of the systems to verify system components and support equipment were aligned correctly and were operable. The inspectors examined the material condition of the components and observed operating parameters of equipment to verify that there were no deficiencies. The inspectors also reviewed whether PSEG staff had properly identified equipment issues and entered them into the CAP for resolution with the appropriate significance characterization.

b. Findings

No findings were identified.

1R05 Fire Protection

.1 Resident Inspector Quarterly Walkdowns (71111.05Q – 5 samples)

a. Inspection Scope

The inspectors conducted tours of the areas listed below to assess the material condition and operational status of fire protection features. The inspectors verified that PSEG controlled combustible materials and ignition sources in accordance with administrative procedures. The inspectors verified that fire protection and suppression equipment was available for use as specified in the area pre-fire plan, and passive fire barriers were maintained in good material condition. The inspectors also verified that station personnel implemented compensatory measures for out of service, degraded, or inoperable fire protection equipment, as applicable, in accordance with procedures.

- Unit 2, Containment, on October 18, 2012
- SW Pipe Trench and Tunnel, on October 25, 2012
- Unit 1, Diesel Fuel Oil Storage Area, Elevation 84', on December 4, 2012
- Unit 2, Diesel Fuel Oil Storage Area, Elevation 84', on December 4, 2012
- Unit 1, Electrical Penetration Area, 78' elevation, on December 4, 2012

b. Findings

Introduction: The inspectors identified a Green NCV of the Unit 1 Operating License Condition 2.C because PSEG did not maintain an adequate CO2 inventory to ensure the operability of the installed deluge fire suppression system in accordance with the approved Fire Protection Plan. Specifically, the CO2 tank liquid level gage was not calibrated periodically, the gage was stuck at 72 percent level for a period of five months, and the tank lost pressure and was inoperable because it was empty on September 1, 2012.

Description: The purpose of the Unit 1 ten ton CO2 tank is to provide inventory for fire suppression for each of the EDG spaces, the diesel fuel oil transfer pump room, and the diesel fuel oil storage tank rooms. PSEG procedure FRS-II-445, "Pre-Fire Plan Diesel Generator Area," has a short statement on the effects of fire on safe shutdown and discusses that the EDGs and their support equipment may provide an essential backup AC power source for the plant during shutdown. A fire in this area must be contained in the room of fire origin as at least two of the three EDGs are required for safe plant shutdown.

On September 1, 2012, at 11:16 pm, the fire protection CO2 pressure high or low alarm was actuated in the main control room. PSEG personnel determined the alarm was due to low CO2 tank pressure in the Unit 1 ten ton low pressure CO2 tank. Pressure was at 280 psig, which was below the minimum required pressure of 285 psig. Control room operators declared the tank inoperable and implemented compensatory measures in the spaces affected by a loss of CO2 deluge suppression, specifically an hourly fire watch was established for the Unit 1 EDGs and the diesel fuel oil storage tank rooms. PSEG technicians conducted troubleshooting on the CO2 deluge system and determined that the level gage was stuck at 72 percent indicated level, and that there was no liquid left in the tank. The inspectors conducted log reviews and interviewed fire protection personnel and determined that the level gage reading had been steady at 72 percent from April 4, 2012 until the tank was declared inoperable early on September 2, 2012. The PSEG procedure FP-AA-005, “Fire Protection Surveillance and Periodic Test Program,” requires that the ten ton CO2 tank level be at least 25 percent for operability of the CO2 deluge system. Because the tank level gage remained at 72 percent from April 4, 2012 until the tank was determined to be empty on September 2, 2012, the inspectors concluded that the tank was inoperable for more than 30 days due to inadequate CO2 inventory.

NFPA 12, “Carbon Dioxide Extinguishing System Systems,” Appendix A, states that proper operation of the liquid level gage should be verified as a part of periodic tank maintenance and that this maintenance should be performed at least annually. Based on this information, the inspectors requested PSEG personnel review the PM program for the ten ton liquid CO2 tank. PSEG staff determined that a PM for the liquid level gage calibration had been generated in 2008 following NRC questions. This PM was rolled to the performance centered maintenance template review in 2009, and was not scheduled to be performed until 2014 when the next periodic maintenance on other CO2 tank components was scheduled to be performed. Previous to this determination and future scheduling, no preventative maintenance had been performed on the liquid level gage. The preventative maintenance for this gage prior to the PM initiated in 2008, was to replace when there was a material problem detected. In response to this issue, PSEG immediately established compensatory measures to restore fire protection system operability of the affected spaces on September 2, 2012, and then completed replace-ment of the failed tank liquid level gage, a leak check of the tank and associated piping, and refilled the liquid CO2 tank to restore the CO2 tank to operable status on October 23, 2012.

The inspectors determined that PSEG’s preventative maintenance plan did not include appropriate vendor recommendations for maintenance on the CO2 level gage that was required to be operable to ensure that the plants fire protection equipment remained operable. The inspectors concluded that the inadequate preventative maintenance for this gage resulted in the inoperability of the fire protection system for EDG spaces, the diesel fuel oil transfer pump room, and the diesel fuel oil storage tank rooms for more than 30 days. PSEG entered the inadequate preventative maintenance issue into the CAP as notification 20573227. Because PSEG did not identify the failure to follow appropriate vendor recommendations as a contributor to the self-revealing gage failure in their corrective actions, the inspectors determined that this finding met the MC 0612 criteria for classification as NRC-identified.

Analysis: The inspectors determined that PSEG’s failure to perform adequate maintenance on the ten ton low pressure liquid CO2 tank was a performance deficiency. NFPA 12, "Carbon Dioxide Extinguishing Systems," Appendix A, states that proper operation of the liquid level gage should be verified as a part of system maintenance, and that this maintenance should be performed at least annually. PSEG had generated a PM to calibrate the liquid level gage in 2008, but this PM had not been implemented as of September 1, 2012. The finding was determined to be more than minor because it affected the protection against external factors attribute of the Mitigating Systems cornerstone, in that it impacted automatic fire suppression capability, and affected the cornerstone objective of ensuring the availability of systems that respond to external events. The finding was evaluated under IMC 0609, Appendix F, "Fire Protection Significance Determination Process." The finding was assigned to the fixed fire suppression system category with a degradation factor of High. Due to the exposure period, a duration factor of 1.0 was applied. The fire frequencies of IMC 0609, Appendix F, Table 1.4.2, "Generic Fire Area Frequencies," was compared to the frequencies in the licensee's Individual Plant Examinations for External Events (IPEEE) table 4.2. Since the frequencies in the IPEEE were more conservative, they were utilized in the evaluation. The plant damage state for a fire in any of the areas was determined to be no more severe than a general plant transient. Offsite power was determined not to be impacted. The conditional core damage probability was calculated utilizing SAPHIRE 8 for Salem Unit 1. Since the delta core damage frequency calculated in step 2.1.4 of Appendix F was less than the value specified in table 2.1.3, "Phase 2 Screening Step 1 Quantitative Screening Criteria," the finding was determined to be of very low safety significance (Green).

This finding has a cross-cutting aspect in the area of human performance, work control component because PSEG did not appropriately coordinate work activities by incorporating actions to plan work activities to support long-term equipment reliability by limiting safety system unavailability and reliance on manual actions. Specifically, a liquid level gage calibration PM to maintain operability of the ten ton CO2 tank was created in accordance with vendor guidance in 2008, but the PM had not been implemented as of September 1, 2012. (H.3(b))

<u>Enforcement</u>: Operating License Condition 2.C requires, in part, that PSEG shall implement and maintain in effect all provisions of the approved fire protection program as described in the UFSAR, and as approved in the NRC Safety Evaluation Report dated November 20, 1979. UFSAR, Section 9.5.1.1, "Fire Protection Program," states that the fire protection program consists of design features, equipment, personnel, and procedures that provide defense in depth protection, which is described in several documents. PSEG procedure FP-AA-005, "Fire Protection Surveillance and Periodic Test Program," section 4.7.10.3.2, states that each of the required CO2 systems shall be demonstrated operable at least once per seven days by verifying tank levels in the ten ton CO2 tank to be greater than or equal to 25 percent liquid level. Contrary to the above, between April 4, 2012 and September 2, 2012, PSEG did not demonstrate that each of the required CO2 systems was operable at least once per seven days by verifying levels in the ten ton CO2 tank to be greater than or equal to 25 percent liquid level. Specifically, because the CO2 tank level gage that PSEG used to verify level was stuck at an indicating level of 72 percent, but actual level was less than 72 percent, it could not be used to verify tank level. Because this finding was of very low safety significance (Green), PSEG established compensatory measures to restore fire protection system operability of the affected spaces until the failed gage was replaced and the CO2 tank was refilled. The issue was entered into PSEG's CAP as notification 20573227

and this violation is being treated as an NCV, consistent with the NRC Enforcement Policy. (**NCV 05000272/2012005-01, Failure to Maintain Adequate Liquid CO2 Inventory for Fire Suppression**)

1R07 Heat Sink Performance (71111.07A – 2 samples)

a. Inspection Scope

The inspectors reviewed the Unit 2 22 CCW HX and the Unit 2 safety injection (SI) pump room cooler to determine their readiness and availability to perform their safety functions. The inspectors reviewed the design basis for the component and verified PSEG's commitments to NRC Generic Letter 89-13. The inspectors walked down the HXs with the PSEG 89-13 engineer while they were open for maintenance. The inspectors discussed the results of the most recent inspection with engineering staff and reviewed pictures of the as-found and as-left conditions. The inspectors verified that PSEG initiated appropriate corrective actions for identified deficiencies. The inspectors also verified that the number of tubes plugged within the HX did not exceed the maximum amount allowed.

b. Findings

No findings were identified.

1R08 In-Service Inspection (71111.08 - 1 sample)

a. Inspection Scope

From October 15 - 26, 2012, the inspectors conducted a review of PSEG's implementation of in-service inspection (ISI) program activities for monitoring degradation of the reactor coolant system boundary, risk significant piping and components, and containment systems during the Salem Unit 2 refueling outage (2R19). The sample selection was based on the inspection procedure objectives and risk priority of those pressure retaining components in these systems where degradation would result in a significant increase in risk. The inspectors observed in-process non-destructive examinations (NDEs), reviewed documentation, and interviewed PSEG personnel to verify that the NDE activities were conducted in accordance with the requirements of the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code Section XI.

Non-Destructive Examination and Welding Activities (IMC Section 02.01)

The inspectors performed direct observations of NDE activities in process and reviewed records of NDEs listed below. Activities inspected included observations of manual ultrasonic testing (UT) techniques for UT calibration, UT in-progress on plant welds, and data review for components tested.

ASME Code Required Examinations

- The UT of the 22 steam generator tube sheet to shell stub barrel and upper head to shell welds performed in accordance with UT procedure 54-ISI-130-047.

- The UT calibration and examinations in progress for testing the main steam isolation valve bonnet studs per procedure 54-ISI-840-006.
- The UT of the main steam pipe to elbow weld 32-MS-2221-2 performed in accordance with procedure 54-ISI-835-014.
- The technique for ultrasonic examination UT procedure 54-ISI-132-011 of the steam generator feedwater nozzle to shell inner radius as implementation of the technique developed by Electric Power Research Institute (EPRI) modeling, IR-2006-250, was discussed with the UT technician and the completed examination data package was reviewed.
- The task work orders and test data for several ultrasonic and visual examinations were reviewed and confirmed to be evaluated by PSEG as part of the ISI process.
- A sample of visual inspection (VT) included the areas of the containment liner inner boundary where insulation panels temporarily removed for visual examination and thickness measurement using UT. The inspectors reviewed the visual examination method, scope, and results of the containment liner boundary examinations and observed a sample of these areas in the plant for comparison to the ASME Code Section XI IWE requirements.
- The video records of the VT examination of the 23 steam generator hot and cold leg lower head nozzle inner radii were reviewed. The visual video records of examinations of the steam generator lower head internal clad surfaces per the advisory letter NSAL-12-1 were also reviewed.
- The application of liquid penetrant testing (PT) for control rod drive mechanism (CRDM) housings number 73, 58, and 69 was evaluated by review of Work Order 50141316, the PT procedure OU-AA-335-002, and a discussion with the NDE technician scheduled to do the work to confirm he was prepared to do the PT examination per the procedural requirements and work order.
- Observed the inspection and seal installations of the joints in a portion of the underground 24-inch diameter concrete SW discharge piping to the circulating water system. The pipe joint inspection and coating parameters were reviewed and the seal type along with a section of the pipe inner diameter were also observed.

The inspectors reviewed certifications of the NDE technicians performing the examinations. The inspectors also verified that the inspections were performed in accordance with approved procedures and that the results were reviewed and evaluated by certified Level III NDE personnel.

<u>Review of Originally Rejectable Indications Accepted by Evaluation</u>

There were no ASME Section XI NDE indications from previous outages that required follow-up inspection during 2R19.

<u>Repair/Replacement Consisting of Welding Activities</u>

For component replacement work, the inspectors observed the installation and reviewed the work orders for the replacement of two of the charging pumps. The work instruction package including the requirements for welding, and related quality verifications were reviewed. Additionally, the radiographic testing procedure and radiographs for one of the new pipe welds (4-inch diameter, 0.531-inch thickness) were reviewed.

Pressurized-Water Reactor Vessel Upper Head Penetration Inspection Activities (IMC Section 02.02)

The Salem Unit 2 reactor pressure vessel head with CRDM penetrations was replaced in 2005 and inspected for leakage in 2009. The inspectors confirmed that the next visual inspection was scheduled in accordance with the requirements of the ASME Code Case N-729-1.

Boric Acid Corrosion Control Inspection Activities (IMC Section 02.03)

The inspectors confirmed the extent of plant boric acid walkdowns during the plant shutdown process and noted that identified problem areas were documented in the corrective action program for resolution. The welding modification of socket welds to a 2X1 slope in the boron injection tank room area as a fatigue failure mitigation activity per EPRI TR-113890 (PWRMRP-07) was also observed.

Steam Generator Tube Inspection Activities (IMC Section 02.04)

The inspectors reviewed various aspects of the steam generator tube eddy current testing (ECT) program, noting that ECT inspections in 2R19 were planned for all the tubes in each steam generator including the tube U-bend areas. The inspectors reviewed the Salem Unit 2 document 51-9164803, “Condition Monitoring for 2R18 and Final Operational Assessment for Cycle 19,” and document 51-9184395-000, “Steam Generator Degradation Assessment for 2R19.”

The inspectors confirmed that procedure ER-AP-420-0051, “Conduct of Steam Generator Management Activities,” and other documentation listed in the references were being properly implemented by conducting interviews with members of the ECT inspection team and review of computer based records. The inspectors noted that eddy current analysts were qualified and confirmed to be prepared for the site specific conditions of the Salem Unit 2 steam generators by applicable testing. The inspectors reviewed the Examination Technique Specification Sheets 1, 2, 3, 4, and 5 for the various ECT probes and techniques used in the ECT test process. The inspectors reviewed the ECT data flow and evaluation process, confirmatory verification of data, the process for resolving initial differences in ECT calls, and the data management final evaluation and closeout process. The acquisition of data and the data analysis process were observed. The independent quality data analyst work scope was reviewed to confirm the extent of independent oversight of the ECT process.

The overall level of tube degradation was assessed noting that while some tubes were plugged, no tube pulls or in-situ testing was required. At a mid-point in the ECT examination process, the inspectors participated in a telephone conference call between the Salem ECT staff and NRC Nuclear Reactor Regulation Steam Generator Branch.

Identification and Resolution of Problems (IMC Section 02.05)

The inspectors reviewed a sample of notifications, which identified NDE indications, deficiencies, and other nonconforming conditions since the previous refueling outage. The inspectors verified that nonconforming conditions were properly identified, characterized, evaluated, corrective actions identified and dispositioned, and appropriately entered into the CAP.

b. Findings

No findings were identified.

1R11 Licensed Operator Requalification Program (71111.11Q – 2 samples, 71111.11A – 1 sample)

.1 Quarterly Review of Licensed Operator Requalification Testing and Training

a. Inspection Scope

The inspectors observed licensed operator simulator training on December 6, 2012, which included a seismic event coincident with a fuel failure, steam generator tube rupture, stuck open steam generator safety valve and the failure of selected components to automatically start as required. The inspectors evaluated operator performance during the simulated event and verified completion of risk significant operator actions, including the use of abnormal and emergency operating procedures. The inspectors assessed the clarity and effectiveness of communications, implementation of actions in response to alarms and degrading plant conditions, and the oversight and direction provided by the control room supervisor. The inspectors verified the accuracy and timeliness of the emergency classification made by the shift manager and the technical specification action statements entered by the shift technical advisor. Additionally, the inspectors assessed the ability of the crew and training staff to identify and document crew performance problems.

b. Findings

No findings were identified.

.2 Quarterly Review of Licensed Operator Performance in the Main Control Room

a. Inspection Scope

The inspectors observed and reviewed the Unit 2 reactor shutdown for a refueling outage on October 14, 2012, Unit 2 B train mode operations test conducted on October 16, 2012, and the Unit 1 reactor startup transition from auxiliary feedwater to main feedwater conducted on November 2, 2012. The inspectors observed infrequently performed test or evolution briefings, procedure use, crew communications, coordination of activities between work groups, and the oversight and direction provided by the control room supervisor to ensure it met Operations

Fundamentals, OP-AA-101-111-1002, Steam Generator Feed Pump Operation, S2.OP-CN-0002, and Cold Shutdown to Hot Standby, S2.OP-IO.ZZ-0002.

b. Findings

No findings were identified.

.3 Annual In-Office Review by Regional Specialist

a. Inspection Scope

On December 27, 2012, a region-based inspector conducted an in-office review of results of the PSEG-administered comprehensive written exams and annual operating tests. The inspection assessed whether pass rates were consistent with the guidance of IMC 0609, Appendix I, "Operator Requalification Human Performance Significance Determination Process (SDP)." The inspector verified that:

- Individual pass rate on the dynamic simulator test was greater than 80 percent. (The pass rate was 97.1 percent.)
- Individual pass rate on the job performance measures of the operating exam was greater than 80 percent. (The pass rate was 100 percent.)
- Individual pass rate on the written examination was greater than 80 percent. (The pass rate was 95.7 percent.)
- More than 80 percent of the individuals passed all portions of the exam. (The pass rate was 92.8 percent.)
- Crew pass rate was greater than 80 percent. (The pass rate was 100 percent.)

b. Findings

No findings were identified.

1R12 Maintenance Effectiveness (71111.12 – 1 sample)

a. Inspection Scope

The inspectors reviewed the Unit 1 and Unit 2 SI pumps the week of December 17, 2012, to assess the effectiveness of maintenance activities on SSC performance and reliability. The inspectors reviewed system health reports, CAP documents, maintenance work orders, and maintenance rule basis documents to ensure that PSEG was identifying and properly evaluating performance problems within the scope of the maintenance rule. The inspectors verified that the SSC was properly scoped into the maintenance rule in accordance with 10 CFR 50.65 and verified that the (a)(2) performance criteria established by PSEG staff was reasonable. Additionally, the inspectors ensured that PSEG staff was identifying and addressing common cause failures that occurred within and across maintenance rule system boundaries.

b. Findings

No findings were identified.

1R13 Maintenance Risk Assessments and Emergent Work Control (71111.13 – 3 samples)

a. Inspection Scope

The inspectors reviewed station evaluation and management of plant risk for the maintenance and emergent work activities listed below to verify that PSEG performed the appropriate risk assessments prior to removing equipment for work. The inspectors selected these activities based on potential risk significance relative to the reactor safety cornerstones. As applicable for each activity, the inspectors verified that PSEG personnel performed risk assessments as required by 10 CFR 50.65(a)(4) and that the assessments were accurate and complete. When PSEG performed emergent work, the inspectors verified that operations personnel promptly assessed and managed plant risk. The inspectors reviewed the scope of maintenance work and discussed the results of the assessment with the station's probabilistic risk analyst to verify plant conditions were consistent with the risk assessment. The inspectors also reviewed the technical specification requirements and inspected portions of redundant safety systems, when applicable, to verify risk analysis assumptions were valid and applicable requirements were met.

- Unit 1, SSOP and 13 containment fan coil unit OOS for planned maintenance on November 15, 2012
- Unit 2, 23 Control area chiller, 23 CCW pump, 22 containment spray pump, and 2C1 125 VDC battery charger OOS for planned maintenance on December 12, 2012
- Unit 1, 12 CCW HX OOS for planned maintenance on December 17, 2012

b. Findings

No findings were identified.

1R15 Operability Determinations and Functionality Assessments (71111.15 – 5 samples)

a. Inspection Scope

The inspectors reviewed operability determinations for the following degraded or non-conforming conditions:

- SW intake structure degraded seal penetrations on September 20, 2012
- Unit 1, 1N31 Source range nuclear instrument spiking before reactor plant startup on November 1, 2012
- Unit 2, 2B 125 VDC Battery discharge test computer failure on November 6, 2012
- Unit 2, Containment sump level transmitter 2LT938 calibration identified out of specification voltages on November 6, 2012
- Unit 2, 21-24SJ16 stem height position change for containment sump recirculation on November 9, 2012

The inspectors selected these issues based on the risk significance of the associated components and systems. The inspectors evaluated the technical adequacy of the operability determinations to assess whether TS operability was properly justified and the subject component or system remained available such that no unrecognized increase in risk occurred. The inspectors compared the operability and design criteria in the appropriate sections of the TSs and UFSAR to PSEG's evaluations to determine whether the components or systems were operable. Where compensatory measures were required to maintain operability, the inspectors determined whether the measures in place would function as intended and were properly controlled by PSEG. The inspectors determined, where appropriate, compliance with bounding limitations associated with the evaluations.

b. Findings

No findings were identified.

1R18 Plant Modifications (71111.18 – 1 sample)

.1 Permanent Modifications

a. Inspection Scope

The inspectors evaluated a modification to replace the existing 22 centrifugal charging pump carbon steel casing, internal element, and mechanical seals. The inspectors verified that the design bases, licensing bases, and performance capability of the affected systems were not degraded by the modification. In addition, the inspectors reviewed modification documents associated with the upgrade and design change, including changing the pump casing from carbon steel to stainless steel, installation of mechanical seals that do not require an external source of water cooling, and the abandonment in place of the existing mechanical seal HXs and CCW piping. The inspectors also interviewed engineering personnel, and performed a walkdown of the completed modification to ensure the modification was installed as designed.

b. Findings

No findings were identified.

1R19 Post-Maintenance Testing (71111.19 – 5 samples)

a. Inspection Scope

The inspectors reviewed the post-maintenance tests for the maintenance activities listed below to verify that procedures and test activities ensured system operability and functional capability. The inspectors reviewed the test procedure to verify that the procedure adequately tested the safety functions that may have been affected by the maintenance activity, that the acceptance criteria in the procedure was consistent with the information in the applicable licensing basis and/or design basis documents, and that the procedure had been properly reviewed and approved. The inspectors also witnessed the test or reviewed test data to verify that the test results adequately demonstrated restoration of the affected safety functions.

- 21 charging pump replacement on November 5, 2012
- 2CV180 boric acid blender check valve replacement on November 6, 2012

- 21 SI pump motor replacement on November 14, 2012
- 22 containment spray pump casing corrective maintenance on November 11, 2012
- 12 CCW HX solenoid operated valve replacement on December 17, 2012

b. Findings

No findings were identified.

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

a. Inspection Scope

The inspectors reviewed the station's work schedule and outage risk plan for the Unit 2 maintenance and refueling outage (2R19), which was conducted October 14 through November 18, 2012. The inspectors reviewed PSEG's development and implementation of outage plans and schedules to verify that risk, industry experience, previous site-specific problems, and defense-in-depth were considered. During the outage, the inspectors observed portions of the shutdown and cooldown processes and monitored controls associated with the following outage activities:

- Configuration management, including maintenance of defense-in-depth, commensurate with the outage plan for the key safety functions and compliance with the applicable TSs when taking equipment OOS
- Implementation of clearance activities and confirmation that tags were properly hung and that equipment was appropriately configured to safely support the associated work or testing
- Installation and configuration of reactor coolant pressure, level, and temperature instruments to provide accurate indication and instrument error accounting
- Status and configuration of electrical systems and switchyard activities to ensure that TSs were met
- Monitoring of decay heat removal operations
- Impact of outage work on the ability of the operators to operate the spent fuel pool cooling system
- Reactor water inventory controls, including flow paths, configurations, alternative means for inventory additions, and controls to prevent inventory loss
- Activities that could affect reactivity
- Maintenance of containment as required by TSs
- Refueling activities, including fuel handling and fuel receipt inspections
- Fatigue management
- Identification and resolution of problems related to refueling outage activities

b. Findings

No findings were identified.

1R22 Surveillance Testing (71111.22 – 5 samples)

a. Inspection Scope

The inspectors observed performance of surveillance tests and/or reviewed test data of selected risk-significant SSCs to assess whether test results satisfied TSs, the UFSAR, and PSEG procedure requirements. The inspectors verified that test acceptance criteria were clear, tests demonstrated operational readiness and were consistent with design documentation, test instrumentation had current calibrations and the range and accuracy for the application, tests were performed as written, and applicable test prerequisites were satisfied. Upon test completion, the inspectors considered whether the test results supported that equipment was capable of performing the required safety functions. The inspectors reviewed the following surveillance tests:

- S2.OP-ST.DG-0013, 2B EDG Endurance Run on October 11, 2012
- S2.OP-ST.SSP-0004, SEC Mode Ops Testing for 2C vital bus on October 15, 2012
- S2.OP-ST.SSP-0003, SEC Mode Ops Testing for 2B vital bus on October 16, 2012
- S2.OP-LR.CVC-0001, 2CV3, letdown orifice isolation valve leak rate test on October 23, 2012
- S2.OP-ST.MS-0002, 21-24BF22, steam generator feed water stop check valves, in-service testing on November 16, 2012

b. Findings

No findings were identified.

Cornerstone: Emergency Preparedness

1EP6 Drill Evaluation (71114.06 – 1 sample)

.1 Emergency Preparedness Drill Observation

a. Inspection Scope

The inspectors evaluated the conduct of a routine PSEG emergency drill on December 6, 2012, to identify any weaknesses and deficiencies in the classification, notification, and protective action recommendation development activities. The inspectors observed emergency response operations in the simulator and technical support center to determine whether the event classification, notifications, and protective action recommendations were performed in accordance with procedures. The inspectors also attended the station drill critique to compare inspector observations with those identified by PSEG staff in order to evaluate PSEG's critique and to verify whether PSEG staff were properly identifying weaknesses and entering them into the CAP.

b. Findings

No findings were identified.

2. RADIATION SAFETY

Cornerstones: Public Radiation Safety and Occupational Radiation Safety

2RS1 Radiological Hazard Assessment and Exposure Controls (71124.01)

This area was inspected to: (1) review and assess PSEG's performance in assessing the radiological hazards in the workplace associated with licensed activities and the implementation of appropriate radiation monitoring and exposure control measures for both individual and collective exposures; (2) verify PSEG is properly identifying and reporting Occupational Radiation Safety cornerstone performance indicators; and (3) identify those performance deficiencies that were reportable as a performance indicator and which may have represented a substantial potential for overexposure of the worker.

During the weeks of October 8 and October 15, 2012, the inspectors interviewed the radiation protection manager, radiation protection supervisors, radiation protection technicians, and radiation workers. The inspectors performed walkdowns of various portions of the station, performed independent radiation dose rate measurements, observed work activities in radiological controlled areas (RCAs), and reviewed PSEG documents. The inspectors used the requirements in 10 CFR 20, guidance in Regulatory Guide (RG) 8.38, "Control of Access to High and Very High Radiation Areas for Nuclear Plants," the TSs, and PSEG procedures required by TSs as criteria for determining compliance.

a. Inspection Scope

Inspection Planning

The inspectors reviewed 2011 and 2012 PSEG performance indicators for the occupational exposure cornerstone for Salem Units 1 and 2. The inspectors reviewed the results of available radiation protection audits. The inspectors reviewed any reports of operational occurrences related to occupational radiation safety since the last inspection.

Radiological Hazard Assessment

The inspectors determined if there had been changes to plant operations since the last inspection that may have resulted in a significant new radiological hazard for onsite workers or members of the public. The inspectors evaluated whether PSEG assessed the potential impact of these changes and had implemented periodic monitoring, as appropriate, to detect and quantify the radiological hazard. Inspect

The inspectors reviewed various radiological surveys from radiological work locations within the Unit 1 and Unit 2 auxiliary building and Unit 2 reactor building. The inspectors evaluated whether the thoroughness and frequency of the surveys were appropriate for the given new radiological hazard.

The inspectors conducted walkdowns and independent radiation measurements in the facility, including radioactive waste processing, storage, and handling areas to evaluate material and radiological conditions.

The inspectors selectively reviewed radiologically risk-significant work activities (e.g., fuel transfer canal entry, reactor vessel head removal). For these work activities, the inspectors assessed whether the radiological surveys performed 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 radiological hazards were properly identified (e.g., discrete radioactive particles, transuranics, other hard to detect nuclides in air samples, transient dose rates, and large gradients in radiation dose rate).

The inspectors observed work in potential airborne areas and evaluated whether the air samples were representative of the breathing air zone and were properly evaluated. The inspectors evaluated whether continuous air monitors were located in areas with low background to minimize false alarms and provided air sample results representative of actual work areas. The inspectors evaluated PSEG's program for monitoring levels of loose surface contamination in areas of the plant with the potential for the contamination to become airborne.

Instructions to Workers

The inspectors selectively evaluated whether containers holding radioactive materials were labeled and controlled in accordance with 10 CFR Part 20 requirements.

The inspectors reviewed radiation work permits (RWPs) used to access high radiation areas (HRAs) and evaluated if the specified work control instructions and control barriers were consistent with TS requirements for HRAs (e.g., fuel transfer canal, reactor cavity).

For these RWPs, the inspectors assessed whether allowable stay times or permissible dose for radiologically significant work under each RWP were clearly identified and controls were consistent with TS requirements. The inspectors evaluated whether electronic personal dosimeter (EPD) alarm setpoints were reasonable and in conformance with survey indications and plant procedural requirements.

The inspectors reviewed instances where a worker's EPD noticeably malfunctioned or alarmed. The inspectors evaluated whether workers responded appropriately to the off-normal condition. The inspectors assessed whether the issue was included in the CAP and whether compensatory dose evaluations were conducted, as appropriate.

For work activities that could result in sudden increase in radiological conditions, the inspectors assessed PSEG's means to inform workers of these changes that could significantly impact their occupational dose.

Contamination and Radioactive Material Control

The inspectors observed locations where PSEG monitors potentially contaminated material leaving the RCA and inspected the methods used for control, survey, and release of these materials from these areas. The inspectors observed the performance of personnel surveying and releasing material for unrestricted use and evaluated whether the work was performed in accordance with plant procedures. The inspectors assessed whether radiation monitoring instrumentation used for equipment release and personnel contamination surveys had appropriate sensitivity for the type(s) of radiation present.

The inspectors reviewed PSEG's criteria for the survey and release of potentially contaminated material. The inspectors evaluated whether there was guidance on how to respond to an alarm that indicated the presence of licensed radioactive material.

The inspectors reviewed PSEG's procedures and records to verify that radiation detection instrumentation was used at its typical sensitivity level based on appropriate counting parameters.

Radiological Hazards Control and Work Coverage

The inspectors evaluated ambient radiological conditions and performed independent radiation measurements during the walkdowns of the facility, including the Unit 2 reactor building. The inspectors assessed whether the conditions were consistent with applicable posted surveys, RWPs, and associated worker briefings.

The inspectors evaluated the adequacy of radiological controls, such as required surveys, radiation protection job coverage, and contamination controls. The inspectors evaluated PSEG's use of EPDs in high noise areas that were also HRAs.

The inspectors assessed, during job observations, whether radiation monitoring devices were placed on the individual's body consistent with PSEG procedures. The inspectors assessed whether the dosimeter was placed in the location of highest expected dose or that PSEG properly implemented an NRC-approved method of determining effective dose equivalent.

The inspectors reviewed the application of dosimetry to effectively monitor exposure to personnel in high-radiation work areas with significant dose rate gradients.

The inspectors reviewed RWPs for work within potential airborne radioactivity areas (e.g., fuel transfer canal) with the potential for individual worker internal exposures.

For these RWPs, the inspectors evaluated airborne radioactive controls and monitoring, including potential for significant airborne levels. The inspectors assessed applicable containment barriers integrity and the operation of temporary high-efficiency particulate air ventilation system.

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 assessed whether appropriate controls were in place to preclude inadvertent removal of these materials from the pool.

The inspectors examined the posting and physical controls for selected HRAs and very high radiation areas (VHRAs) to verify conformance with the occupational performance indicator.

Risk-Significant HRA and VHRA Controls

The inspectors discussed the controls and procedures for high-risk HRAs and VHRAs with the radiation protection manager, radiation protection supervisors, and radiation protection technicians. The inspectors assessed whether any changes to

PSEG relevant procedures substantially reduced the effectiveness and level of worker protection.

The inspectors discussed with first-line health physics supervisors and technicians the controls in place for special areas that had the potential to become VHRAs during certain plant operations. The inspectors assessed whether these plant operations required communication beforehand with the health physics group, so as to allow corresponding timely actions to properly post, control, and monitor the radiation hazards including re-access authorization.

The inspectors evaluated PSEG controls for VHRAs and areas with the potential to become a VHRA to ensure that an individual was not able to gain unauthorized access to these VHRAs.

Radiation Worker

The inspectors observed the performance of radiation workers with respect to stated radiation protection work requirements. The inspectors assessed whether workers were aware of the radiological conditions in their workplace, RWP controls/limits in place, and whether their behavior reflected the level of radiological hazards present. The inspectors interviewed various workers during the Unit 2 refueling outage to assess their understanding of ambient radiological conditions or expected changes in conditions.

The inspectors reviewed available radiological problem reports since the last inspection. The inspectors evaluated whether there was an observable pattern traceable to a similar cause. The inspectors assessed whether this perspective matched the corrective action approach taken by PSEG to resolve the reported problems.

Radiation Protection Technician Proficiency

The inspectors observed the performance of the radiation protection technicians with respect to controlling radiation work. The inspectors evaluated whether technicians were aware of the radiological conditions in their workplace, the RWP controls/limits, and whether their behavior was consistent with their training and qualifications with respect to the radiological hazards and work activities.

The inspectors reviewed available radiological problem reports since the last inspection. The inspectors evaluated whether there was an observable pattern traceable to a similar cause. The inspectors assessed whether this perspective matched the corrective action approach taken by PSEG to resolve the reported problems.

Problem Identification and Resolution

The inspectors evaluated whether problems associated with radiation monitoring and exposure control were being identified by PSEG at an appropriate threshold and were properly addressed for resolution in their CAP. The inspectors assessed the appropriateness of the corrective actions for a selected sample of problems documented by PSEG that involved radiation monitoring and exposure controls. The inspectors assessed PSEG's process for applying operating experience to their plant.

b. Findings

No findings were identified.

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

This area was inspected during the weeks of October 8 and October 15, 2012, to assess performance with respect to maintaining occupational individual and collective radiation exposures as low as reasonably achievable (ALARA). The inspectors used the requirements in 10 CFR Part 20, RG 8.8, "Information Relevant to Ensuring that Occupational Radiation Exposures at Nuclear Power Plants will be As Low As Reasonably Achievable," RG 8.10, "Operating Philosophy for Maintaining Occupational Radiation Exposure As Low as Reasonably Achievable," the TSs, and PSEG's procedures required by TSs as criteria for determining compliance.

a. Inspection Scope

Inspection Planning

The inspectors reviewed pertinent information regarding Salem Unit 1 and Unit 2 collective dose history, current exposure trends, and ongoing or planned activities in order to assess current performance and exposure challenges. The inspectors also reviewed the plant's three year rolling average collective exposure.

The inspectors compared the site-specific trends in collective exposures against the industry average values and those values from similar vintage reactors. In addition, the inspectors reviewed any changes in the radioactive source term. The inspectors reviewed site-specific procedures associated with maintaining occupational exposures ALARA, which included a review of processes used to estimate and track exposures from specific work activities.

Radiological Work Planning

The inspectors selected various work activities that had the expected highest exposure significance and reviewed PSEG's planning and preparation for the work activities as well as ongoing work.

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

The inspectors assessed whether PSEG's planning identified appropriate dose reduction techniques; considered alternate dose reduction features; and estimated reasonable dose goals. The inspectors evaluated whether 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 whether 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 assessed the integration of ALARA requirements into work procedure and RWP documents.

The inspectors compared the results achieved (dose rate reductions, person-rem used), as available, 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 actual person-hours for the work activity time requirements, and evaluated the accuracy of these time estimates. The inspectors assessed the reasons for any inconsistencies between intended and actual work activity doses.

The inspectors determined whether work in progress reviews were conducted to identify lessons learned. If problems were identified, the inspectors verified that worker suggestions for improving dose/contamination reduction techniques were entered into PSEG's CAP.

Verification of Dose Estimates and Exposure Tracking Systems

The inspectors reviewed the assumptions and basis for the current annual collective exposure estimate for accuracy. The inspectors reviewed applicable procedures to determine the methodology for estimating exposures from specific work activities and for department and station dose goals.

The inspectors evaluated whether PSEG had established measures to track, trend, and if necessary, reduce occupational doses for ongoing work activities. The inspectors assessed whether dose threshold criteria was established to prompt additional reviews and/or additional ALARA planning and controls.

The inspectors evaluated PSEG's method of adjusting exposure estimates, or re-planning work, when unexpected changes in scope or emergent work were encountered. The inspectors assessed whether adjustments to exposure estimates were based on sound radiation protection and ALARA principles or if they were just adjusted to account for failures to plan/control work.

Source Term Reduction and Control

The inspectors discussed with PSEG staff and used PSEG records to determine the historical trends and current status of plant source term known to contribute to elevated facility collective exposure. The inspectors assessed whether PSEG had made allowances or developed contingency plans for expected changes in the source term as the result of changes in plant fuel performance issues or changes in plant primary chemistry. The inspectors reviewed chemistry data for evaluating source term clean-up. The inspectors made independent radiation measurements to evaluate source term clean-up efforts.

Radiation Worker Performance

The inspectors observed radiation worker and radiation protection technician performance during work activities performed in radiation areas, airborne radioactivity areas, and HRAs. The inspectors evaluated whether workers demonstrated the ALARA philosophy in practice (e.g., workers are familiar with the work activity scope and tools to be used, workers used ALARA low-dose waiting areas) and whether there were any procedure compliance issues.

Problem Identification and Resolution

The inspectors evaluated whether problems associated with ALARA planning and controls were being identified by PSEG at an appropriate threshold and were properly addressed for resolution in their CAP.

b. Findings

No findings were identified.

2RS3 In-Plant Airborne Radioactivity Control and Mitigation (71124.03)

This area was inspected during the weeks of October 8 and October 15, 2012, to verify in-plant airborne concentrations were being controlled consistent with ALARA principles and the use of respiratory protection devices onsite did not pose an undue risk to the wearer. The inspectors used the requirements in 10 CFR Part 20, the guidance in RG 8.15, "Acceptable Programs for Respiratory Protection," RG 8.25, "Air Sampling in the Workplace," NUREG-0041, "Manual of Respiratory Protection Against Airborne Radioactive Material," the TSs, and PSEG procedures required by TSs as criteria for determining compliance.

a. Inspection Scope

Inspection Planning

The inspectors reviewed the Salem Unit 1 and Unit 2 UFSAR to identify areas of the plant designed as potential airborne radiation areas and any associated ventilation systems or airborne monitoring instrumentation. This review included instruments used to identify changing airborne radiological conditions such that actions to prevent an internal uptake may be taken. The review included, as available, an overview of the respiratory protection program and a description of the types of devices used. The inspectors reviewed reported performance indicators to identify any related to unintended dose resulting from intakes of radioactive material.

Engineering Controls

The inspectors reviewed PSEG's use of permanent and temporary ventilation to determine whether PSEG used ventilation systems as part of its engineering controls to control and limit airborne radioactivity. The inspectors reviewed procedural guidance for use of installed plant systems to reduce dose and assessed whether the systems are used, to the extent practicable, during high-risk activities.

The inspectors selected various installed ventilation systems used to mitigate the potential for airborne radioactivity. The inspectors evaluated whether the ventilation system operating parameters were consistent with maintaining concentrations of airborne radioactivity in work areas below the concentrations of an airborne radioactive material area.

The inspectors selected various temporary ventilation system setups used to support work in contaminated areas. The inspectors assessed whether the use of these systems was consistent with PSEG procedural guidance and ALARA concept. The inspectors assessed whether PSEG had established threshold criteria for evaluating levels of airborne beta-emitting and alpha-emitting radionuclides.

Use of Respiratory Protection Devices

The inspectors selected Salem Unit 2 reactor cavity work activities and assessed whether PSEG performed an evaluation concluding that further engineering controls were not practical and if the use of respirators was appropriate. The inspectors also evaluated whether PSEG had established means (such as routine bioassay and passive monitoring) to determine if the level of protection (protection factor) provided by the respiratory protection devices during use was at least as good as that assumed in PSEG's work controls and dose assessment.

The inspectors assessed whether respiratory protection devices used to limit the intake of radioactive materials were certified by the National Institute for Occupational Safety and Health/Mine Safety and Health Administration (NIOSH/MSHA) or have been approved by the NRC. The inspectors evaluated whether the devices were used consistent with their NIOSH/MSHA certification or NRC approval.

The inspectors reviewed records of air testing for supplied-air devices to assess whether the air used in these devices meet or exceeds Grade D quality. The inspectors reviewed plant breathing air supply systems to determine whether they meet the minimum pressure and airflow requirements for the devices in use.

Problem Identification and Resolution

The inspectors evaluated whether problems associated with the control and mitigation of in-plant airborne radioactivity were being identified by PSEG at an appropriate threshold and were properly addressed for resolution in their CAP. The inspectors assessed whether the corrective actions were appropriate for a selected sample of problems involving airborne radioactivity and were appropriately documented by PSEG.

b. Findings

No findings were identified.

2RS4 Occupational Dose Assessment (71124.04)

This area was inspected during the weeks of October 8 and October 15, 2012, to ensure occupational dose was appropriately monitored and assessed. The inspectors used the requirements in 10 CFR Part 20, the guidance in RG 8.13, "Instructions Concerning Prenatal Radiation Exposures," RG 8.36, "Radiation Dose to Embryo Fetus," RG 8.40, "Methods for Measuring Effective Dose Equivalent from External Exposure," the TSs, and PSEG's procedures required by TSs as criteria for determining compliance.

a. Inspection Scope

Inspection Planning

The inspectors reviewed the results of available radiation protection program audits and self-assessments related to internal and external dosimetry. The inspectors reviewed the most recent National Voluntary Laboratory Accreditation Program (NVLAP) accreditation report on PSEG vendor's most recent results to determine the status of the accreditation.

A review was conducted of PSEG procedures associated with dosimetry operations, including issuance/use of external dosimetry, assessment of internal dose, and evaluation of and dose assessment for radiological incidents.

The inspectors evaluated whether PSEG had established procedural requirements for determining when external dosimetry and internal dose assessments were required.

External Dosimetry

The inspectors evaluated whether PSEG's dosimetry vendor was NVLAP accredited and if the approved irradiation test categories for each type of personnel dosimeter used are consistent with the types and energies of the radiation present and the way the dosimeter is being used.

The inspectors selectively evaluated the onsite storage of dosimeters before issuance, during use, and before processing/reading. The inspectors also reviewed the guidance provided to radiation workers with respect to care and storage of dosimeters.

The inspectors assessed the use of EPDs to determine if PSEG uses a "correction factor" to address the response of the EPD as compared to the dosimeter of legal record for situations when the EPD is used to assign dose and whether the correction factor is based on sound technical principles.

The inspectors reviewed various dosimeter occurrence reports or corrective action program documents for adverse trends related to EPDs. The inspectors assessed whether PSEG had identified any adverse trends and implemented appropriate corrective actions.

Internal Dosimetry

Routine Bioassay (In Vivo)

The inspectors reviewed procedures used to assess the dose from internally deposited radionuclides using whole body counting equipment. The inspectors evaluated whether the procedures addressed methods for differentiating between internal and external contamination, the release of contaminated individuals, determining the route of intake, and the assignment of dose.

The inspectors reviewed the whole body count process to determine if the frequency of measurements was consistent with the biological half-life of the radionuclides available for intake.

The inspectors reviewed PSEG's evaluation for use of its portal radiation monitors as a passive monitoring system. The inspectors assessed if instrument minimum detectable activities were adequate to determine the potential for internally deposited radionuclides sufficient to prompt an investigation.

Internal Dose Assessment - Airborne Monitoring

The inspectors reviewed PSEG's program for dose assessment based on airborne monitoring and calculations of derived air concentration calculations. The inspectors determined whether flow rates and collection times for air sampling equipment were adequate to allow appropriate lower limits of detection to be obtained. The inspectors also reviewed the adequacy of procedural guidance to assess internal dose if respiratory protection was used.

Internal Dose Assessment - Whole Body Counter Analyses

The inspectors discussed dose assessments performed by PSEG using the results of whole body counter analyses. The inspectors determined whether affected personnel were properly monitored with calibrated equipment and that internal exposures were assessed consistent with PSEG's procedures.

Special Dosimetric Situations

Declared Pregnant Workers

The inspectors assessed whether PSEG informed workers of the risks of radiation exposure to the embryo/fetus, the regulatory aspects of declaring a pregnancy, and the specific process to be used (voluntarily) declaring a pregnancy.

Dosimeter Placement and Assessment of Effective Dose Equivalent for External Exposures

The inspectors reviewed PSEG's methodology for monitoring external dose in non-uniform radiation fields or where large dose gradients exist. The inspectors evaluated PSEG's criteria for determining when alternate monitoring, such as use of multi-badges was to be implemented.

Shallow Dose Equivalent

The inspectors reviewed available dose assessments for shallow dose equivalent for adequacy. The inspectors evaluated PSEG's method (e.g., VARSKIN or similar code) for calculating shallow dose equivalent from distributed skin contamination or discrete radioactive particles.

Neutron Dose Assessment

The inspectors selectively evaluated PSEG's neutron dosimetry program, including dosimeter types and/or radiation survey instrumentation.

The inspectors reviewed available neutron exposure occurrences and assessed whether dosimetry and/or instrumentation was appropriate for the expected neutron spectra, there was sufficient sensitivity for low dose and/or dose rate measurement, and neutron dosimetry and/or neutron detection instruments were properly calibrated. The inspectors also assessed whether interference by gamma radiation had been accounted for in the calibration and whether time and motion evaluations were representative of actual neutron exposure events, as applicable.

Problem Identification and Resolution

The inspectors assessed whether problems associated with occupational dose assessment are being identified by PSEG at an appropriate threshold and are properly addressed for resolution in their CAP. The inspectors assessed the appropriateness of the corrective actions for a selected sample of problems documented by PSEG involving occupational dose assessment.

b. Findings

No findings were identified.

2RS5 Radiation Monitoring Instrumentation (71124.05)

This area was inspected during the weeks of October 8 and October 15, 2012, to verify PSEG was assuring the accuracy and operability of radiation monitoring instruments that are used to protect occupational workers and to protect the public from nuclear power plant operations. The inspectors used the requirements in 10 CFR Part 20, the TSs, applicable industry standards, and PSEG's procedures required by TSs as criteria for determining compliance.

a. Inspection Scope

Inspection Planning

The inspectors reviewed the Salem Unit 1 and Unit 2 UFSAR to identify radiation instruments associated with monitoring area radiation, airborne radioactivity, process streams, effluents, materials/articles, and workers. The inspectors reviewed a listing of in-service survey instrumentation including air samplers and small article monitors, along with radiation monitoring instruments used to detect and analyze workers' external contamination as well as external dose. Additionally, the inspectors reviewed personnel contamination monitors and portal monitors including whole body counters to detect to workers' surface and internal contamination. The inspectors assessed whether an adequate number and type of instruments were available to support operations.

The inspectors reviewed available PSEG and third-party evaluation reports of the radiation monitoring program since the last inspection, including evaluations of offsite calibration facilities or services, if applicable.

The inspectors reviewed procedures that govern instrument source checks and calibrations, focusing on instruments used for monitoring transient high radiological conditions, including instruments used for underwater surveys. The inspectors reviewed the calibration and source check procedures for adequacy. The inspectors selectively reviewed the area radiation monitor alarm setpoint values for portable units.

Walkdowns and Observations

The inspectors selected various portable survey instruments in use or available for issuance and assessed calibration and source check stickers for currency, as well as instrument material condition and operability.

The inspectors discussed source checks for various different types of portable survey instruments. The inspectors assessed whether high-range instruments were source checked on all appropriate scales.

The inspectors selectively assessed operation and placement of local area radiation monitors and continuous air monitors to determine whether they were appropriately positioned relative to the radiation sources or areas they were intended to monitor. The inspectors compared monitor response (via local readout or remote control room indications) with actual area radiological conditions for consistency.

The inspectors selected various personnel contamination monitors, portal monitors, and small article monitors and evaluated whether the periodic source checks were performed in accordance with the manufacturer's recommendations and PSEG procedures.

Laboratory Instrumentation

The inspectors selectively assessed laboratory analytical instruments used for radiological analyses to determine whether daily performance checks and calibration data indicate that the frequency of the calibrations was adequate and there were no indications of degraded performance.

Portal Monitors, Personnel Contamination Monitors, and Small Article Monitors

The inspectors selected various types of these instruments and verified that the alarm setpoint values were reasonable under the circumstances to ensure that licensed material was not released from the site.

The inspectors reviewed the calibration documentation for each selected instrument and reviewed the calibration methods to determine consistency with the manufacturer's recommendations.

Portable Survey Instruments, Area Radiation Monitors, Electronic Dosimetry, and Air Sampler/Continuous Air Monitors

The inspectors reviewed calibration documentation for various types of portable instruments. For portable survey instruments and area radiation monitors, the inspectors reviewed detector measurement geometry and calibration methods and reviewed the use of its instrument calibrator as applicable.

Instrument Calibrator

The inspectors selectively reviewed the current radiation output values for PSEG's portable survey instrument calibrator unit.

Calibration and Check Sources

The inspectors reviewed PSEG's source term or waste stream characterization per 10 CFR Part 61, "Licensing Requirements for Land Disposal of Radioactive Waste," to assess whether calibration sources used were representative of the types and energies of radiation encountered in the plant.

Problem Identification and Resolution

The inspectors evaluated whether problems associated with radiation monitoring instrumentation were being identified by PSEG at an appropriate threshold and were properly addressed for resolution in their CAP. The inspectors assessed the appropriateness of the corrective actions for a selected sample of problems documented by PSEG that involved radiation monitoring instrumentation.

b. Findings

No findings were identified.

Cornerstone: Public Radiation Safety

2RS6 Radioactive Gaseous and Liquid Effluent Treatment (71124.06)

This area was inspected during the week of October 15, 2012, to evaluate the adequacy of effluent release and public dose calculations resulting from radioactive effluent discharges.

The inspectors used the requirements in 10 CFR Part 20, 10 CFR 50.35(a), 10 CFR 50, Appendix I, "Numerical Guides for Design Objectives and Limiting Conditions for Operations to Meet the Criterion As Low As Reasonably Achievable (ALARA) for Radioactive Material in Light-Water - Cooled Nuclear Power Reactor Effluents," applicable industry standards, TSs, and PSEG procedures required by the TSs and Offsite Dose Calculation Manual (ODCM) as criteria for determining compliance.

a. Inspection Scope

Inspection Planning and Program Reviews

Event Report and Effluent Report Reviews

The inspectors reviewed the Salem Radiological Effluent Release Report for 2011 to determine if the report was submitted as required by the ODCM/TSs. The inspectors reviewed anomalous results, unexpected trends, or abnormal releases identified by

PSEG. The inspectors determined if these effluent results were evaluated, entered in the CAP, and adequately resolved.

Dose Calculations

The inspectors reviewed all significant changes in reported dose values compared to the previous radioactive effluent release report to evaluate the factors that may have resulted in the change.

The inspectors reviewed changes in PSEG's methodology for offsite dose calculations since the last inspection to verify the changes were consistent with the ODCM and RG 1.109. The inspectors reviewed meteorological dispersion and deposition factors used in the ODCM and effluent dose calculation to ensure appropriate dispersion/deposition factors were being used for public dose calculations.

The inspectors reviewed the latest Land Use Census to verify that changes in the local land use have been factored into the dose calculations and environmental sampling/analysis program.

The inspectors evaluated whether the calculated doses were within the 10 CFR Part 50, Appendix I and TS dose criteria.

Problem Identification and Resolution

The inspectors assessed whether problems associated with the effluent monitoring and control program were being identified by PSEG at an appropriate threshold and were properly addressed for resolution in their CAP.

b. Findings

No findings were identified.

4. OTHER ACTIVITIES

4OA1 Performance Indicator Verification (71151 – 6 samples)

.1 Mitigating Systems Performance Index

a. Inspection Scope

The inspectors reviewed PSEG's submittal of the Mitigating Systems Performance Index for the following systems for the period of October 1, 2011 through September 30, 2012:

- Unit 1 and Unit 2 Emergency AC Systems
- Unit 1 and Unit 2 High Pressure Injection Systems

To determine the accuracy of the performance indicator data reported during those periods, the inspectors used definitions and guidance contained in Nuclear Energy Institute (NEI) Document 99-02, "Regulatory Assessment Performance Indicator G

Guideline," Revision 6. The inspectors also reviewed PSEG's operator narrative logs, condition reports, mitigating systems performance index derivation reports, event reports, and NRC integrated inspection reports to validate the accuracy of the submittals.

b. Findings

No findings were identified.

.2 Occupational Exposure Control Effectiveness

a. Inspection Scope

The inspectors sampled PSEG submittals for the occupational radiological occurrences performance indicator for the period of October 1, 2011 through September 30, 2012. The inspectors used performance indicator definitions and guidance contained in NEI Document 99-02, "Regulatory Assessment Performance Indicator Guideline," Revision 6, to determine the accuracy of the performance indicator data reported during those periods. The inspectors reviewed PSEG's assessment of the performance indicator for occupational radiation safety to determine if the related data was adequately assessed and reported.

To assess the adequacy of PSEG's performance indicator data collection and analyses, the inspectors discussed with radiation protection staff the scope and breadth of its data review and the results of those reviews. The inspectors independently reviewed EPD accumulated dose alarms, dose reports, and dose assignments for any intakes that occurred during the time period reviewed to determine if there were potentially unrecognized performance indicator occurrences. The inspectors also conducted walkdowns of various locked HRA and VHRA entrances to determine the adequacy of the controls in place for these areas.

b. Findings

No findings were identified.

.3 Radiological Effluent TS/ODCM Radiological Effluent Occurrences

a. Inspection Scope

The inspectors sampled PSEG submittals for the radiological effluent TS/ODCM radiological effluent occurrences performance indicator for the period of October 1, 2011 through September 30, 2012. The inspectors used performance indicator definitions and guidance contained in NEI Document 99-02, "Regulatory Assessment Performance Indicator Guideline," Revision 6, to determine if the performance indicator data was reported properly during this period. The inspectors reviewed the public dose assessments for the performance indicator for public radiation safety to determine if related data was accurately calculated and reported.

The inspectors reviewed PSEG's issue report database and selected individual reports generated since this indicator was last reviewed to identify any potential occurrences such as unmonitored, uncontrolled, or improperly calculated effluent releases that may have impacted offsite dose. The inspectors reviewed gaseous and liquid effluent summary data and the results of associated offsite dose calculations during those periods to determine if indicator results were accurately reported.

b. Findings

No findings were identified.

4OA2 Problem Identification and Resolution (71152 – 4 samples)

.1 Routine Review of Problem Identification and Resolution Activities

a. Inspection Scope

As required by Inspection Procedure 71152, "Problem Identification and Resolution," the inspectors routinely reviewed issues during baseline inspection activities and plant status reviews to verify that PSEG entered issues into the CAP at an appropriate threshold, gave adequate attention to timely corrective actions, and identified and addressed adverse trends. In order to assist with the identification of repetitive equipment failures and specific human performance issues for follow-up, the inspectors performed a daily screening of items entered into the CAP and periodically attended condition report screening meetings.

b. Findings

No findings were identified.

.2 Semi-Annual Trend Review

a. Inspection Scope

The inspectors performed a semi-annual review of site issues, as required by Inspection Procedure 71152, "Problem Identification and Resolution," to identify trends that might indicate the existence of more significant safety issues. In this review, the inspectors included repetitive or closely-related issues that may have been documented by PSEG outside of the CAP, such as trend reports, performance indicators, major equipment problem lists, system health reports, maintenance rule assessments, and maintenance or CAP backlogs. The inspectors also reviewed PSEG's CAP database for the six-month period of June 1, 2012 through November 30, 2012, to assess condition reports written on equipment problems and human performance issues, as well as individual issues identified during the NRCs daily condition report review (Section 4OA2.1). The inspectors reviewed the PSEG nuclear oversight report for the period of May through August 2012 to verify that PSEG personnel were appropriately evaluating and trending adverse conditions in accordance with applicable procedures.

b. Findings and Observations

No findings were identified.

The inspectors noted a negative trend in the reliability and availability of the chemical and volume control (CVC) positive displacement pumps (PDPs) on Units 1 and 2. Both 13 and 23 CVC PDPs had a significant amount of unavailability over the review period which included a loss of all charging and seal injection flow in July 2012, when the 13 CVC PDP failed in service. PSEG placed both the CVC PDPs in maintenance rule condition (a)(1) and performed repairs to 13 CVC PDP relief valve and pulsation dampeners and realigned the fluid head of the 23 CVC PDP after several unsuccessful packing replacements of the pump. Both the 13 and 23 CVC PDPs have a monitoring plan and goals in place. The inspectors verified that all the issues with the CVC PDPs were addressed within the scope of the CAP and in system health reports and that appropriate corrective actions have been accomplished.

The inspectors noted an apparent significant increase in the number of foreign material exclusion (FME) issues that have occurred. Over 95 percent of FME related notifications were written during the Unit 2 refueling outage and many of these notifications involved actual foreign material entry or foreign material discovery in a plant system as compared to a missing or incorrectly installed FME barrier. The inspectors noted that these FME issues were not recognized by PSEG staff as a specific emerging or adverse trend, but concluded that the issue was not more than minor in accordance with IMC 0612, because none of the individual FME issues associated with the identified trend had adversely impacted the affected system's safety function. PSEG entered this issue into the CAP as notification 20588922 for further review.

Additionally, the inspectors noted an increase in the number of maintenance tagging events over the review period including several during the Unit 2 refueling outage. PSEG has also identified this issue in trending their adverse conditions, has entered this issue into the CAP as notification 20573275, and is in the process of conducting a root cause evaluation on the issue. The inspectors reviewed each individual tagging issue and the aggregate of the issues and concluded that no issue was more than minor, in accordance with IMC 0612, because no safety functions were adversely impacted by the tagging errors.

.3 Annual Sample: Emergency Core Cooling System (ECCS) Check Valve Mechanical Agitation

a. Inspection Scope

The inspectors performed an in-depth review of PSEG's technical evaluations, process controls, and corrective actions associated with their use of mechanical agitation to seat emergency core cooling system (ECCS) check valves during leakage testing. Specifically, in November 2010, PSEG initiated corrective action notification 20484075 to develop a technical evaluation to support existing engineering memorandums and vendor guidance on the mechanical agitation of ECCS check valves. Subsequently, in March 2011, engineering developed technical evaluation 70115963 to formally document, review and approve, and establish appropriate process controls for ECCS check valve mechanical agitation.

The inspectors assessed PSEG's problem identification threshold, associated engineering evaluations, extent-of-condition reviews, compensatory actions, and the prioritization and timeliness of corrective actions to determine whether PSEG was appropriately identifying, characterizing, and correcting problems associated with ECCS check valve leakage and whether the planned or completed corrective actions were appropriate. The inspectors compared the actions taken to the requirements of PSEG's CAP, TSs, PSEG's Inservice Test Program, NRC Inspection Manual Part 9900 Technical Guidance, and 10 CFR Part 50, Appendix B. In addition, the inspectors performed field walkdowns and interviewed operations and engineering personnel to assess the effectiveness of the implemented corrective actions. Specifically, the inspectors walked down accessible Unit 1 and Unit 2 SI piping and components (including in-plant and control room instrumentation) to independently assess the material condition and PSEG's problem identification. The inspectors also reviewed a sample of maintenance work orders, leakage test results, condition monitoring plans, historical valve leakage trends, and operating procedures to verify that PSEG adequately maintained ECCS check valves in accordance with the TSs, operating procedures, vendor recommendations, and NRC guidelines.

b. Findings and Observations

No findings were identified.

The inspectors noted that periodic check valve leakage testing is controlled by PSEG procedure OP-ST.SJ-0020, "Periodic Leakage Test RCS Pressure Isolation Valves," and performed at a lower pressure than design operating pressure (leakage results are corrected to reflect the leakage at the design operating conditions). Typically, operators perform the testing at a pressure of 1000 psi to 1700 psi, whereas the normal operating line pressure is 2485 psi. Engineering determined that the lower pressure drop across the ECCS check valves under test conditions may not provide sufficient differential pressure to properly seat the check valve. To preclude unacceptable preconditioning, operators documented as-found leakage results and compared them to TS acceptance criteria before any additional troubleshooting or mechanical agitation was permitted. Any additional troubleshooting and/or mechanical agitation occurred outside of the leakage testing procedure and were controlled within PSEG's CAP. On occasion, technicians used mechanical agitation to ascertain the condition of the valve seat. However, prior to using mechanical agitation, technicians used other measures, where possible, such as varying the pressure or flushing, to fully seat the check valve.

Based on vendor input and operational experience, engineering incorporated detailed guidance into their mechanical agitation technical evaluation that was specific to each respective check valve. If mechanical agitation was used to troubleshoot a check valve with as-found leakage above the TS requirement, PSEG's procedure required the check valve to be exercised open (forward flow test) or internally inspected prior to re-performing the leakage test, or required engineering to evaluate the respective valve's maintenance and leakage history to determine if the leakage test results obtained following mechanical agitation were acceptable. When an engineering technical evaluation accepted the test results after mechanical agitation without any follow-up forward flow testing, PSEG's procedures required an internal inspection of the check valve during the next refueling outage.

Based on a review of leakage test results and maintenance history, the inspectors noted that PSEG infrequently exercised the mechanical agitation option; and when they did, they performed technical evaluations as required and appropriately tracked and implemented actions to open and inspect the affected check valves during the next refueling outage. For example, for Unit 1, no check valves were mechanically agitated in 1R19, three were agitated in 1R20 (and subsequently inspected in 1R21), and none were agitated in 1R21 in November 2011. For Unit 2, no check valves were mechanically agitated in 2R17, three were agitated in 2R18 (and subsequently inspected in 2R19), and one was agitated in 2R19 in November 2012 (notification 20583764 initiated to open and inspect in 2R20). Based on interviews and a maintenance history review, the inspectors noted that mechanical agitation did not adversely impact ECCS check valve operation or result in any internal check valve damage. The inspectors noted that procedure OP-ST.SJ-0020 also required operators to initiate a corrective action notification on any check valve leakage greater than 0.0 gpm regardless if the actual leak rate was acceptable or not. PSEG uses such notifications to drive an in-service testing program engineer trend analysis to determine appropriate corrective actions.

The inspectors concluded that PSEG had taken timely and appropriate action in accordance with TSs, operating and administrative procedures, and PSEG's CAP. Based on the work orders and CAP documents reviewed, and interviews with engineering and operations personnel, the inspectors noted that PSEG personnel demonstrated an increased sensitivity to potential preconditioning and an appropriate safety focus regarding the mechanical agitation of ECCS check valves and did so only as a last resort to fully seat check valves with minimal seat leakage. The inspectors determined that PSEG's technical evaluations associated with ECCS check valve leakage and mechanical agitation were sufficiently thorough and based on the best available information, troubleshooting, sound engineering judgment, and relevant operating history. PSEG's assigned corrective actions were aligned with operating and program procedure requirements, adequately tracked, appropriately documented, and completed as scheduled. Based on the documents reviewed, plant walkdowns, and discussions with engineering and operations personnel, the inspectors noted that PSEG personnel identified problems and entered them into their CAP at a low threshold.

.4 Annual Sample: Degraded Voltage Relay

a. Inspection Scope

The inspectors performed an in-depth review of PSEG's root cause analysis and corrective actions associated with issues related to the degraded voltage relay (DVR) setpoint calculations. The issues were the result of inspection findings 05000272; 311/2008007-01 and 05000272; 311/2011007-01 as captured in notifications 20494513, 20497060, and 20497062. Specifically, PSEG had not adequately verified that safety-related equipment would operate under all voltages afforded by the DVR.

The inspectors assessed PSEG's problem identification threshold, cause analyses, extent of condition reviews, compensatory actions, and the prioritization and timeliness of PSEG's corrective actions to determine whether PSEG was appropriately identifying, characterizing, and correcting problems associated with this issue and whether the planned and completed corrective actions were appropriate. The inspectors compared the actions taken to the requirements of PSEG's corrective action program and 10 CFR Part 50, Appendix B. In addition, the inspectors interviewed engineering personnel to assess the effectiveness of the implemented corrective actions.

b. Findings and Observations

No findings were identified.

In response to NRC findings and self-identified issues with the DVR setpoint calculations, PSEG performed a root cause evaluation, operability evaluations for bounding and worst-case equipment, and revised the DVR setpoint calculations.

PSEG's root cause evaluation performed a thorough review of the current and historical issues related to the DVR setpoint calculations. PSEG determined that the root and contributing causes for the inadequacies were: human error with data collection; lack of technical standard for DVR setpoint calculations; and an insufficient understanding of the regulatory requirements. In response, PSEG performed an extent of condition review for incorrect data, revised the Design Engineering Technical Standard with the correct method to establish the DVR settings, and revised the DVR setpoint calculations.

Currently, PSEG has finished the primary DVR setpoint calculations and verified operability for safety-related equipment. PSEG has future actions to finalize the review of some control circuits and most motor-operated valves (MOVs). PSEG has reviewed the worst case control circuits and MOVs. The remaining control circuits are bounded by the current analysis so no issues are expected with the future reviews. The full review of MOVs required the completion of the DVR setpoint calculations to accurately calculate the expected bus voltage for each of the MOVs. Since the DVR setpoint calculations were completed at the end of November 2012, actions have been implemented, but are still ongoing for performing the full MOV review.

The inspectors reviewed the completed DVR setpoint calculations and operability evaluations and did not identify any additional issues. The inspectors determined PSEG's overall response to the issue was commensurate with the safety significance and was timely. The inspectors determined that the actions taken were reasonable to resolve the issues as identified in the NRC findings and PSEG's self assessments.

However, the inspectors' review did identify that several conclusions in the revised calculation ES-15.017, Salem Unit 1 and 2 Analytical Voltage Analysis, included statements that further reviews were required with no clear documentation that the reviews were completed. PSEG presented information to the inspectors that showed the reviews were in fact completed as part of the design change request review process, but PSEG agreed that referencing undocumented reviews in the conclusions section was not in accordance with site procedures and generated notification 20587296 to address the issue. This issue was determined to be minor because the reviews had been performed.

.5 Annual Sample: Intermediate Range Nuclear Instrument Trip Setpoints

a. Inspection Scope

The inspectors reviewed the apparent cause evaluation for the incorrectly calculated intermediate range trip setpoints which occurred on November 23, 2011. The inspectors reviewed the corrective actions assigned and the effectiveness of these corrective actions. The inspectors interviewed the Reactor Engineering Manager and one Reactor Engineer involved in the event.

b. Findings and Observations

No findings were identified.

The inspectors observed that actions have been taken by the Reactor Engineering Department to revise Reactor Engineering procedures to incorporate human factors enhancements and specifically to require a concurrent verification for the data collection steps. This specifically addresses the apparent cause of the intermediate range trip setpoint calculation during which the reactor engineer misread a meter in the control room and subsequently used incorrect values in the calculations.

In addition, a common cause evaluation for post-maintenance testing revealed deficiencies in the work package preparation. Changes in the work package development process have been implemented to enhance the required post-maintenance testing requirements. Proper post-maintenance testing following the intermediate range trip setpoint adjustment would have alerted the operations staff to the mistake in the calculation.

The inspectors reviewed the remaining corrective actions determined by the apparent cause evaluation and found that the changes implemented were effective and reasonable.

4OA3 Follow-Up of Events and Notices of Enforcement Discretion (71153 – 1 sample)

.1 Plant Events

a. Inspection Scope

For the plant event listed below, the inspectors reviewed and/or observed plant parameters, reviewed personnel performance, and evaluated performance of mitigating systems. The inspectors communicated the plant events to appropriate regional personnel, and compared the event details with criteria contained in IMC 0309, “Reactive Inspection Decision Basis for Reactors,” for consideration of potential reactive inspection activities. As applicable, the inspectors verified that PSEG made appropriate emergency classification assessments and properly reported the event in accordance with 10 CFR Parts 50.72 and 50.73. The inspectors reviewed PSEG’s follow-up actions related to the event to assure that

PSEG implemented appropriate corrective actions commensurate with their safety significance.

- Unit 1 reactor plant trip on October 30, 2012, due to the loss of four circulating water pumps during Hurricane Sandy

b. Findings

No findings were identified.

4OA5 Other Activities

.1 Temporary Instruction 2515/187 - Inspection of Near-Term Task Force Recommendation 2.3 - Flooding Walkdowns

a. Inspection Scope

The inspectors verified that PSEG's walkdown package, Unit 1 and 2 Auxiliary Buildings, contained the elements as specified in NEI 12-07 (Revision 0-A), May 2012, "Guidelines for Performing Verification Walkdowns of Plant Flood Protection Features" (ADAMS Accession No. ML12173A215).

The inspectors accompanied PSEG on their walkdown of the Unit 2 electrical penetration room and containment spray room, and the Unit 1 EDG fuel oil storage tank area and verified that PSEG confirmed the following flooding protection features:

- Visual inspection of penetration seals, surfaces and doors was performed. External visual inspection for indications of degradation that would prevent its credited function from being performed was performed.
- Available physical margin, where applicable, was determined.
- Flood protection feature functionality was determined using either visual observation or by review of other documents.

The inspectors independently performed their walkdown of the Unit 1 fuel handling building and verified that the following flood protection features were in place:

- Penetration seals in walls and floors
- Water tight doors functioned
- Wall and floor surfaces conditions

The inspectors verified that noncompliances with current licensing requirements, and issues identified in accordance with the 10 CFR 50.54(f) letter, Item 2.g of Enclosure 4, were entered into PSEG's CAP. In addition, issues identified in response to Item 2.g that could challenge risk significant equipment and PSEG's ability to mitigate the consequences will be subject to additional NRC evaluation.

b. Findings

No findings were identified.

.2 Temporary Instruction 2515/188 - Inspection of Near-Term Task Force Recommendation 2.3 - Seismic Walkdowns

a. Inspection Scope

The inspectors accompanied PSEG on their seismic walkdowns of the:

- Unit 1 chill water pump area including: 13CW92 (chiller condenser SW control valve), 13 chiller compressor, 13 chiller, 1 emergency control air compressor aftercooler, 13 chiller condenser recirculation pump, 11 chill water pump, 11 chiller, and 11 chiller compressor on September 21, 2012;
- Unit 2, 84' vital bus electrical area including: 2A 230 V vital bus, transformer to 2A 460 Vac vital bus, and vital switchgear room vent panel on September 19, 2012;
- Units 1 and 2 125 Vdc battery rooms including the 1A 125 Vdc battery and the 2A 125 Vdc battery on September 26, 2012; and
- Unit 1 Control Room including pressurizer level channel 2 indicator, refueling water storage tank level indicator, temperature indicator loop 11 indicator, and main steam pressure loop 12 indicator on September 24, 2012.

The inspectors also verified that PSEG confirmed that the following seismic features were free of potential adverse seismic conditions:

- Anchorage was free of bent, broken, missing, or loose hardware
- Anchorage was free of corrosion that was more than mild surface oxidation
- Anchorage was free of visible cracks in the concrete near the anchors
- SSCs would not be damaged from impact by nearby equipment or structures
- Overhead equipment, distribution systems, ceiling tiles and lighting, and masonry block walls were secure and not likely to collapse onto the equipment
- Attached lines had adequate flexibility to avoid damage
- The area was free of potentially adverse seismic interactions that could cause flooding or spray in the area
- The area was free of potentially adverse seismic interactions that could cause a fire in the area
- The area was free of potentially adverse seismic interactions associated with housekeeping practices, storage of portable equipment, and temporary installations.

The inspectors independently performed their walkdowns of:

- 22 auxiliary feedwater pump in the 84' level of the Unit 2 auxiliary building on December 12, 2012.
- 11 SI pump in the 84' level of the Unit 1 auxiliary building on December 13, 2012.
- 22 SW pump discharge header cross-connect valve, 22SW17 in the SW intake structure on December 13, 2012.
- 1C EDG in the 100' level of the Unit 1 auxiliary building on December 18, 2012.

The inspectors verified that the following seismic features were free of potential adverse seismic conditions:

- Anchorage was free of bent, broken, missing, or loose hardware
- Anchorage was free of corrosion that was more than mild surface oxidation
- Anchorage was free of visible cracks in the concrete near the anchors
- SSCs would not be damaged from impact by nearby equipment or structures
- Overhead equipment, distribution systems, ceiling tiles and lighting, and masonry block walls were secure and not likely to collapse onto the equipment
- Attached lines had adequate flexibility to avoid damage
- The area was free of potentially adverse seismic interactions associated with housekeeping practices, storage of portable equipment, and temporary installations.

Observations made during the walkdown that could not be determined to be acceptable were entered into PSEG's CAP for evaluation.

Additionally, inspectors verified that items that could allow the spent fuel pool to drain down rapidly were added to the seismic walkdown equipment list and were walked down by PSEG.

b. Findings

No findings were identified.

4OA6 Meetings, Including Exit

On January 10, 2013, the inspectors presented the inspection results to Mr. Wagner, Plant Manager of Salem, and other members of PSEG management. The inspectors verified that no proprietary information was retained by the inspectors or documented in this report.

ATTACHMENT: SUPPLEMENTARY INFORMATION

SUPPLEMENTARY INFORMATION

KEY POINTS OF CONTACT

Licensee Personnel
C. Fricker, Site Vice President
L. Wagner, Plant Manager
T. Cachaza, Regulatory Assurance
J. Garecht, Director, Work Management
R. Denight Jr., Operations Director
K. Chambliss, Regulatory Affairs Manager
T. Neufang, Radiation Protection Superintendent
S. Taylor, Radiation Protection Manager
J. Stavely, Nuclear Oversight Manager
J. Pantazes, Nuclear Environmental Affairs Manager
M. Richers, Engineering Manager, Electrical/I&C
J. Russell, Nuclear Environmental Specialist
P. Fabian, Steam Generator Program Manager
T. Giles, ISI Program Manager
T. Oliveri, NDE Project Manager
S. Elkhiamy, Reactor Engineering Manager
C. Dahms, Regulatory Assurance
L. Curran, Senior Manager, Plant Engineering
B. Ketterer, System Engineer
D. Lafleur, Senior Regulatory Compliance Engineer
G. Sosson, Director, Engineering
W. Wikoff, Check Valve Program Engineer

LIST OF ITEMS OPENED, CLOSED, DISCUSSED, AND UPDATED

Opened/Closed

05000272/2012005-01	NCV	Failure to Maintain Adequate Liquid CO2 Inventory for Fire Suppression (Section 1R05)

LIST OF DOCUMENTS REVIEWED

Section 1R01: Adverse Weather Protection

Procedures
ER-AA-310-1009, Condition Monitoring of Structures, Revision 2
LS-AA-119, Fatigue Management and Work Hour Limits, Revision 10
OP-AA-108-111-1001, Severe Weather and Natural Disaster Guidelines, Revision 7
SC.OP-AB.ZZ-0001, Adverse Environmental Conditions, Revision 15
SY-AA-101-109-1003, Security during Hazardous Exterior Conditions, Revision 5

Notifications

20580674	20580768	20580958	20580989	20581048	20581137
20581056	20581065				

Drawings

219507 233677

Section 1R04: Equipment Alignment

Procedures

S1.OP-SO.SW-0001, Service Water Pump Operation, Revision 26
S1.OP-SO.SW-0005, Service Water System Operation, Revision 39
S2.OP-SO.CC-0001, Component Cooling System Operations, Revision 14
S2.OP-SO.CC-0002, 21&22 Component Cooling Heat Exchanger Operations, Revision 22

Notifications (*NRC-identified)

20586019 20586218 20586428 20586483 20586674*

Drawings

205242

Other Documents

Work Clearance Document: 4325358

Section 1R05: Fire Protection

Procedures

FP-SA-003, Actions for Inoperable Fire Protection - Salem Station, Revision 1
FRS-II-435, Salem Unit 1 (Unit 2) Pre-Fire Plan, Diesel Fuel Oil Storage Area, Elevation 84', Revision 5
FRS-II-511, Salem Unit 1 (Unit 2) Pre-Fire Plan, Electrical Penetration Area, Elevations: 78', Revision 5
FRS-II-611, Salem Unit 1 (Unit 2) Pre-Fire Plan, Reactor Containment, Elevations: 78', 100' and 130', Revision 5
FRS-II-912, Salem Unit 1 (Unit 2) Pre-Fire Plan, Service Water Pipe Trench & Tunnel, Revision 2

Notifications (*NRC-identified)

20571951	20575636	20585304	20586356	20586299	20586579*
20586580*					

Other Documents

Salem and Hope Creek Fire Impairment Log Book, dated 12/5/12

Section 1R07: Heat Sink Performance

Procedures

S2.OP-PT.SW-0027, 22 Component Cooling Heat Exchanger Heat Transfer Performance Data Collection, Revision 15

Other Documents
22 CCHX Performance Test, dated 10/15/2012

Section 1R08: In-Service Inspection

Procedures
54-ISI-836- (Rev) 013, UT of Austenitic Piping Welds
54-ISI-132, 011, Pressurizer Surge Line Nozzle UT Procedure
54-ISI-130-047, UT of Ferritic Vessel Welds Greater than 2.0" in Thickness
54-ISI-365-003- Visual Inspection of Pressure Vessel Internals, Attachments, and Internal Surfaces
54-ISI-835-014, UT of Ferritic Piping Welds
54-ISI-840-006, Straight beam UT of Studs and Bolts
ER-AP-331, Boric Acid Corrosion Control (BACC) Program, Revision 5
ER-AP-331-1001, Boric Acid Corrosion Control Inspection Locations, Implementation and Inspection Guidelines, Revision 6
ER-AP-331-1002, Boric Acid Corrosion Control Program Identification, Screening, and Evaluation, Revision 6
OU-AA-335-018, VT1 and VT3 Visual Examination of ASME Class MC and CC Containment Surfaces and Components, Revision 5
OU-AA-335-005, Radiographic Examination, Revision 1
OU-AA-335-002, Liquid Penetrant Examination, Revision 2
OU-AA-335-043, Bare Metal Visual Examination, Penetration welds on lower RPV head, Revision 1
OU-AA 335-1008, Acceptance Criteria, Revision 0

Drawings
NFPMG-08-0014, Salem U2, 61/19T RSG, Channel Head general view and details, Revision C
Salem U2 SG No. 22, Weld / Hanger Identification, ISI Drawing, PI&D 205301, Revision 2
D-3052-619, Rev A, Main Steam Stop Valve Stud UT Cal Block by SwRI, Revision A
Salem U2, S2-ISI-334-1 Safety Injection ISI Boundary Drawing, sheet 1 of 4
201448, Salem U2 Reactor Containment Bottom Liner

Notifications

20578406	20578408	20578505	20578608	20578833	20578915
20579944	20580525	20580541	20582690		

Steam Generator Tube Integrity, Eddy Current Reports/Assessments
Salem Unit 2 Technical Specifications for Steam Generator Tube Integrity
AREVA Document 51-9184395-000, Salem 2R19 Steam Generator Degradation Assessment, dated October 2012
AREVA Document 51-9044781-001, Technical Summary of Salem Unit 2 Replacement Steam Generator Eddy Current Pre-service Inspection January/February 2007
AREVA Document 51-9164803-000, Salem Unit 2 61/19T SG Condition Monitoring for 2R18 and Final Operational Assessment for Cycle 19, dated 7/29/2011
AREVA Examination Technique Specification Sheet (ETSS) 1, bobbin MIZ80, Salem U2, Outage 2R19, Revision 0
AREVA ETSS 2, RPC 3-coil MIZ80, Salem Unit 2, Outage 2R19, Revision 0
AREVA ETSS 3, RPC 1 coil MIZ80, Salem Unit 2, Outage 2R19, Revision 0
AREVA ETSS 4, x-probe MIZ80, Salem Unit 2, Outage 2R19, Revision 0
AREVA ETSS 5, RPC Sizing, Salem Unit 2, Outage 2R19, Revision 0

EPRI Steam Generator Management Program, Pressurized Water Reactor Steam Generator Examination Guidelines, Document 1013706, Revision 7
EPRI Steam Generator Management Program, Steam Generator Integrity Assessment Guidelines, Document 1019038, Revision 3

NDE DATA Sheets/Reports
Radiographic Examination Report for Weld S2-CVC-189-4, ref drawing CV-2-2, SHT-11
Report VT-12-081 for Visual Examination of Penetration welds on the lower RPV Head, per Code Case N-722-1
Steam Generator 22 Tubesheet to Shell Barrel Weld UT, Report UT-12-041
Steam Generator 22 Upper Head to Shell D Weld UT, Report UT-12-023
Main Steam Pipe to Elbow UT of Weld 32-MS-2221-2, Report UT-12-017
Main Steam Valve 23MS167 Studs, Line 34-MS-2231, UT, Report UT-12-021

Other Documents
EPRI Report IR-2006-250, dated December 2006, Salem Unit 2 Replacement Steam Generator Feedwater Nozzle Inner Corner Region Examinations
EPRI Report TR-113890 (PWRMRP-07), Vibration Fatigue Testing of Socket Welds
Boric Acid Corrosion Control (BACC) Discovery List for RFO 2R19
NASL-12-1 Letter dated 1/6/2012 regarding Steam Generator Channel Head Degradation
Salem SAP Order 70133103 addressing NASL 12-1
Salem U1 &U2, Alloy 600 Management Plan, Order 70106866, Revision 3
Follow-up to EPRI Letters 2012-02 and 03, NDE alert for examiners qualified to Appendix VIII, Supplement 10 on dissimilar metal welds, a training and certification action

Section 1R11: Licensed Operator Requalification Program

Procedures
NC.EP-EP.ZZ-0102, Emergency Coordinator Response, Revision 16
SC.OP-AB.ZZ-0004, Earthquake, Revision 4
S2.OP-AB.RC-0002, High Activity in the Reactor Coolant System, Revision 8
2-EOP-LOSC-1, Loss of Secondary Coolant, Revision 23
2-EOP-SGTR-1, Steam Generator Tube Rupture, Revision 27
2-EOP-TRIP-1, Reactor Trip or Safety Injection, Revision 28

Other Documents
PSEG Nuclear, LLC, Salem - Onsite Training Drill (S12-03) Scenario Synopsis, dated 12/06/2012

Section 1R12: Maintenance Effectiveness

Procedures
ER-SA-310-1009, Salem Generating Station – Maintenance Rule Scoping, Revision 3

Notifications (*NRC-identified)

20574198	20543017	20568682	20570436	20543888	20548778
20568588	20568762	20579422	20582389		

Work Orders

60105103	60105064	60080965	60097458

Other Documents
Salem Unit 1, Safety Injection System Health Report 2012 Q-3
Salem Unit 2, Safety Injection System Health Report 2012 Q-3

Section 1R13: Maintenance Risk Assessments and Emergent Work Control

Procedures
OP-AA-101-112-1002, On-Line Risk Management, Revision 6
OP-AA-108-116, Protected Equipment Program, Revision 7
WC-AA-101, On-Line Work Management Process, Revision 19

Other Documents
Salem Generating Station, Unit 2 Risk Assessment, dated 11/15/2012
Salem Generating Station, Unit 1 Risk Assessment, dated 11/15/2012
Salem Generating Station, Unit 2 Risk Assessment, dated 12/12/2012
Salem Generating Station, Unit 1 Risk Assessment, dated 12/12/2012
Work Clearance Documents: 4259088, 4323406, 4323512 and 4326140

Section 1R15: Operability Determinations and Functionality Assessments

Procedures
S2.OP-ST.SJ-0016, High Head Cold Leg Throttling Valve Flow Balance Verification, Revision 30

Notifications

20576548	20574115	20574136	20574138	20574016	20582938

Work Orders

60105092	60104113	60104114	50100171	70145949

Other Documents
S-C-RHR-MEE-1883, GSI-191 Downsteam Effects – Flow Clearances, Revision 1
70144771-0010, Technical Evaluation, Containment Sump Level Transmitter 2LT938 Calibration
70145203-0010, Technical Evaluation, 2B 125 VDC Battery Test Performance Complete with Broken Computer
70142908-0010, Technical Evaluation, Service Water Bay 1 Penetration Seals

Section 1R18: Plant Modifications

Procedures
S2.OP-ST.CVC-0004, Inservice Testing – 22 Charging Pump, Revision 26

Notifications

20578915	20579166	20579630	20579724	20582387	20581903
20582446	20582461	20582461	20582505	20582538	20582823
20583258					

Drawings

205328	218202	232166

Work Orders

60106872	80102631

Other Documents

902163, Vendor Technical Drawing on S-2-CVC-MDS-0493, Salem 22 Charging and Safety Injection Pump, Revision 1

DE-CB.CVC-0037, Chemical and Volume Control, Revision 4

S2011-025, 50.59 Screening for Salem 21 and 22 Centrifugal Charging Pump Casing, Internal Element and Mechanical Seal, Revision 1

Section 1R19: Post-Maintenance Testing

Procedures

MA-AA-716-012, Post Maintenance Testing, Revision 18

S2.OP-ST.SJ-0001, Inservice Testing - 21 Safety Injection Pump, Revision 20

S2.OP-ST.CS-0002, Inservice Testing - 22 Containment Spray Pump, Revision 21

S2.OP-ST.CVC-0003, Inservice Testing – 21 Charging Pump, Revision 25

S1.OP-SO.CC-001, Component Cooling System Operation, Revision 17

SC.IC-PM.ZZ-0002, Disassembly, Inspection, Assembly and Testing of Copes Vulcan Diaphragm Air Operated Actuator Models D100-60, 100, 160, Revision 13

Notifications

20582389	20576262	20583258	20585180	20586583	20588328

Work Orders

30089040	30107916	60106093	60106757	60106872	80102631

Other Documents

80107692-0690, Technical Evaluation, Retest Requirements for 21 Safety Injection Pump Motor Replacement

60106112-0120, Evaluation of Corrosion of 22 Containment Spray Pump Casing Studs in the 2R19 Outage

Section 1R20: Refueling and Other Outage Activities

Procedures

OP-AA-108-108, Unit Restart Review, Revision 11

SC.MD-FR.FH-0012, Reactor Vessel Head Stud Detensioning, Unthreading, Tensioning and Threading, Revision 14

S2.OP-IO.ZZ-0005, Minimum Load to Hot Standby, Revision 22

S2.OP-IO.ZZ-0006, Hot Standby to Cold Shutdown, Revision 43

S2.OP-SO.RC-0005, Draining the Reactor Coolant System to $\geq$ 101 Foot Elevation, Revision 41

Notifications (*NRC-identified)

20578810	20579011	20579123	20579237	20579249	20579751
20583565*	20578597	20581349	20581402	20581576	20582240
20582389	20582491	20582574	20582913	20582917	20583008
20583122	20583569	20583574	20583858	20583935	20584022
20584046	20584055	20584134	20584221	20584238	20584528
20584529	20584537				

Work Orders

60106757	60106965	70123042	70132679	70145098	70145563
80103085					

Other Documents
S2R19 Message, 21SW21 Human Performance Error, dated 11/4/2012
2R19 Major Work Scope Packet
2R19 ORAM Windows Graph, Revision 0
S2R19 T-3 Outage Readiness Assessment
ORAM Contingency Plan, 2R19 Refueling Outage
ORAM Contingency Plan, 2R19 Refueling Outage RCS at mid-loop post refueling
2R19 Outage Risk Assessment Report, Initial Schedule Approval, Revision 0
OU-AA-103, Attachment 1, Shutdown Safety Approval, dated 9/28/2012
OP-SA-108-114-1001, Attachment 3, Post Trip Review - Planned Reactor Trip, dated 10/14/2012
OP-SA-108-114-1001, Form - 2, Sequence of Events Checklist
2-EOP-CFST-1, CFST Status Log Sheet
Fatigue Management Common Solution Worksheets, from 10/15/2012 to 11/11/2012
2R19 Union Manning Worksheets
Salem Operations 2012 Shift Schedule

Section 1R22: Surveillance Testing

Procedures
S2.OP-LR.CVC-0001, Type C Leak Rate Test 2CV3, 2CV4, 2CV5, 2CV6 and 2CV7, Revision 2
S2.OP-ST.DG-0002, 2B EDG Surveillance Test, Revision 47
S2.OP-ST.DG-0013, 2B EDG Endurance Run, Revision 26
S2.OP-ST.MS-0002, S2.OP-ST.MS-0002, Inservice Testing Main Steam and Feedwater Valves, Revision 21
S2.OP-ST.SSP-0003, SEC Mode Ops Testing 2B Vital Bus, Revision 40
S2.OP-ST.SSP-0004, SEC Mode Ops Testing 2C Vital Bus, Revision 36

Notifications

20506475	20579037	20580071

Work Orders

30165704	50100171	50138665	50140603	50140907	50151493
50152729	60100318				

Section 1EP6: Drill Evaluation

Procedures
NC.EP-EP.ZZ-0102, Emergency Coordinator Response, Revision 16
NC.EP-EP.ZZ-0202, Operational Support Center Activation and Operations, Revision 19
SC.OP-AB.ZZ-0004, Earthquake, Revision 4
S2.OP-AB.RC-0002, High Activity in the Reactor Coolant System, Revision 8
2-EOP-LOSC-1, Loss of Secondary Coolant, Revision 23
2-EOP-SGTR-1, Steam Generator Tube Rupture, Revision 27
2-EOP-TRIP-1, Reactor Trip or Safety Injection, Revision 28

Notifications

20586565	20586574	20586836	20587549

Other Documents
PSEG Nuclear, LLC, Salem - Onsite Training Drill (S12-03) Scenario Synopsis, dated 12/06/2012

Section 2RS1: Radiological Hazard Assessment and Exposure Controls

Procedures
RP-AA-200, Access Control Point Management, Revision 0
RP-AA-211, Personnel Dosimetry Performance Verification, Revision 7
RP-AA-281, Comparison of Personnel Dosimeter Results, Revision 2
RP-AA-302, Determination of ALPHA Monitoring Levels, Revision 3
RP-AA-376, Radiological Posting, Labeling and Marking, Revision 6
RP-AA-350, Response to Potentially Contaminated Personnel, Revision 10
RP-AA-401-1001, Special Instructions for Highly Radioactive Incore Components, Revision 0
RP-AA-403, Administration of the Radiation Work Permit Program, Revision 3
RP-AA-460, Control for High and Very High Radiation Areas, Revision 15
RP-AA-605, 10 CFR61 Program, Revision 1
NC.RP-TI.ZZ-0206, Dose Assessment for Airborne Radioactive Material Exposure, Revision 4
SC.RP-TI.ZZ-0105, RP Shift Log Maintenance and Turnover Responsibilities, Revision 4

Notifications

20559185	20559294	20561427	20567861	20567861	20571156
20568233	20574032	20575772	20579080	20579308	20579372
20579463					

Other Documents
Radiological Survey data (various)
Dosimeter - NVLAP certification data
Contamination Control – Personnel Contamination Data
Technical Report No. 2000-01, Evaluation of Portal and Personnel Monitor Sensitivity to Internal Gamma Emitting Radionuclides at PSEG

Section 2RS2: Occupational ALARA Planning and Controls

Procedures
RP-AA-400, ALARA Program, Revision 6
RP-AA-401, Operational ALARA Planning and Control, Revision 12
RP-AA-403, Administration of the Radiation Work Permit Program, Revision 3
CY-AP-120-3000, PWR Shutdown Chemistry for Recirculating Steam generators, Revision 10
S1.CH-IO.ZZ-111, Salem Unit 1 Shutdown Chemistry Plan, Revision 7

Other Documents
ALARA Plans; reactor disassembly (30), transfer canal (31), head lift (31), steam generator activities (38, 40,53) cavity decontamination (60), scaffolding(44)
TEDE ALARA Reviews (transfer canal, steam generator bowel)
SAC Meeting Minutes – Station Goals
Five year ALARA Plan
Salem 1 R21 Outage Dose Report

Section 2RS3: In-plant Airborne Radioactivity Control and Mitigation

Procedures
NC.RP.TI.ZZ-0504, Control and Use of Portable Vacuum Cleaners, Revision 5
RP-AA-825, Maintenance, Care and Inspection of Respiratory Protection Equipment, Revision 4
RP-AA-441, Evaluation and Selection Process for Radiological Respirator Use, Revision 4
NC.RP.-TI.ZZ-0404, Testing and Evaluation of Compressed Breathing Air, Revision 1
NC.RP-TI.ZZ-403, Operation of Breathing Air System, Revision 3

Other Documents
Occupational Dose Summary
Radiological Source Term Data
Airborne Radioactivity Intake Assessments
Corrective Action Documents (various)
Breathing air quality data

Section 2RS4: Occupational Dose Assessment

Procedures
RP-AA-210, Dosimetry Issue, Usage, and Control, Revision 11
RP-AA-211, Personnel Dosimetry Performance Verification, Revision 7
RP-AA-220, Bioassay Program, Revision 7
RP-AA-221, Whole Body Count Data Review, Revision 3
RP-AA-222, Methods for Estimating Internal Exposure from IN Vivo and In Vitro Bioassay, Revision 5
RP-AA-250, External Dose Assessment from Contamination, Revision 6
RP-AA-302, Determination of ALPHA Monitoring Levels, Revision 3
RP-AA-350, Response to Potentially Contaminated Personnel, Revision 10
NC.RP-TI.ZZ-0206, Dose Assessment for Airborne Radioactive Material Exposure, Revision 4

Other Documents
Radiation Protection Technical Bases Document- Plant Radionuclide Mix Evaluation for Dosimetry Performance
2012 Annual Bioassay Program Review
Salem EPD correction factors
NVLAP Scope of Accreditation
Exposure Control and Dose Records
General Source Term Data
Personnel Contamination Event Logs
Personnel Intake Investigations
Notification 20577991

Section 2RS5: Radiation Monitoring Instrumentation

Procedures
RP-AA-302, Determination of ALPHA Monitoring Levels, Revision 3
RP-AA-350, Response to Potentially Contaminated Personnel, Revision 10
RP-AA-401-1001, Special Instructions for Highly Radioactive Incore Components, Revision 0
NC.RP-TI.ZZ-0206, Dose Assessment for Airborne Radioactive Material Exposure, Revision 4
RP-AA-503, Unconditional Release Survey Method, Revision 7

Other Documents

Instrumentation Calibration and Check Data: EPDs 052641, 065152, 064564; IPM8/9 359, 950183; SPM-906 906124; SAM9 0062; AMS3 1111, RAS1 7723, 210961; E-140N 1365; RO2 4387; Telepole 023, 024

Audits and Assessments (FASA 70133618, Check-in 70106827, 70118260, Audit NOSA-SLM-11-07980104891)

Survey Maps - 2213018, 2213019

Section 2RS6: Radioactive Gaseous and Liquid Effluent Treatment

Other Documents

2011 Annual Effluents and Environmental Reports

Offsite Dose Calculation Manual, Revision 26

Section 4OA1: Performance Indicator Verification

Notifications

20513948 20530764 20557652 20584574

Other Documents

Salem 1 Narrative Log, S1 CVC, from 10/1/2011 to 9/30/2012

Salem 1 Narrative Log, S1 EDG, from 10/1/2011 to 9/30/2012

Salem 2 Narrative Log, S2 EDG, from 10/1/2011 to 9/30/2012

Salem 2 Narrative Log, S2 CVC, from 10/1/2011 to 9/30/2012

3Q/2012 Performance Indicators, Salem 1, Mitigating Systems Performance Index, Emergency AC Power System, dated 11/19/2012

3Q/2012 Performance Indicators, Salem 1, Mitigating Systems Performance Index, High Pressure Injection System, dated 11/19/2012

3Q/2012 Performance Indicators, Salem 2, Mitigating Systems Performance Index, Emergency AC Power System, dated 11/19/2012

3Q/2012 Performance Indicators, Salem 2, Mitigating Systems Performance Index, High Pressure Injection System, dated 11/19/2012

Section 4OA2: Problem Identification and Resolution

Procedures

ER-AA-2009, Managing Gas Accumulation, Revision 0

LS-AA-125, Corrective Action Program, Revision 16

PP-AA-3001, Position Paper on Preconditioning, Revision 0

S1.OP-ST.SJ-0020, Periodic Leakage Test RCS Pressure Isolation Valves, Revision 20

S2.OP-SO.SJ-0003, RCS Pressure Isolation Valves Check Valve Reseating, Revision 6

S2.OP-ST.SJ-0009, Emergency Core Cooling ECCS Subsystems - Tavg ≥ 350°F, Revision 20

S2.OP-ST.SJ-0015, Intermediate Head Hot Leg Throttling Valve Flow Balance Verification, Revision 24

S2.OP-ST.SJ-0020, Periodic Leakage Test RCS Pressure Isolation Valves, Revision 20

SC.MD-PM.ZZ-0120, Disassembly, Inspection and Reassembly of Edward Unwelded Check Valve Mark #'s FA-43, FA-45, FA-92, FA-182, FA-184, FA-186, FA-187, FA-188, FA-189, FA-192 and FA-203, Revision 3

S1.MD-FT.4KV-0001, ESFAS Instrumentation Monthly Functional Test, Revision 26

ND.DE-TS.ZZ-2014, Technical Standard for Protective Relaying for 4.16KV and 7.2KV Buses, Revision 3

SC.RE-RA.NIS-0016, Intermediate Range NIS Setpoint Evaluation and Determination, Revision 6
S1.IC-DC.NIS-0034, Intermediate Range 1N35 Bistable Adjustment, Revision 10
S1,IC-DC.NIS-0035, Intermediate Range 1N36 Bistable Adjustment, Revision 10
OP-AA-111-1001, Use and Development of Operating Logs
MA-AA-716-012, Post Maintenance Testing
AD-AA-101-1003, Implementing Procedure Writers Guide
S2.OP-DL.ZZ-0003, Control Room Log-Modes 1-4, Revision 91

Notifications (*NRC-identified)

20494513	20497060	20497062	20587296*	20441927	20484075
20503860	20508879	20508898	20508899	20508997	20509053
20521996	20524342	20524343	20524733	20534866	20558388
20568767	20571389	20574198	20583764	20583935	20584022
20586208	20586238	20586285	20586429	20586469	20586656
20586670	20538425	20557491	20588922*		

Calculations
ES-15.008, Salem Unit 1 & 2 Degraded Grid Study, Revision 0
ES-15.012, Bus Transfer Calculation, Revision 0
ES-15.017, Salem Unit 1 & 2 Analytical Voltage Analysis, Revision 1
S-C-4KV-JDC-959, Sheet 26, Degraded Vital Bus Undervoltage Setpoint, Revision 5

Work Orders

30193593	30193394	30218608	30222185	30223577,	30224050
30224051	50146070	50146188	50146500	50147558	50146459
50147841	60094090	60094833	60096634	60096825	60096828
60097277	60100309	60105551	60100552	70087831	70118887
70142656	70143135	70116455	70127231		

Drawings

205328	205334

Miscellaneous
DCR 80106516, Issue Analytical Voltage Analysis Calculation ES-15.017, Revision 0
DCR 80106477, Revise Calculations ES-15.017, 004, 008, 012, and 014, Revision 0
70096971, Air-Entrained Water Observed While Venting 1SJ170, dated 4/20/09
70115963, Mechanical Agitation of RCS Pressure Isolation Check Valves, dated 5/6/11
70123632, 22SJ144 Back Leakage/Mechanical Agitation, dated 5/5/11
70126422, ECCS Check Valve Leakage, dated 8/23/11
70127990, SI Pump Discharge Header Pressure Increasing Technical Evaluation, dated 9/7/11
70142241, SI Pump Discharge Header Pressure Increasing Technical Evaluation, dated 8/21/12
ECCS Check Valve Notification Trend Data, dated 1/5/06 - 11/25/12
Letter from Valve Engineering Supervisor to Reliability Engineering Manager, Mechanical Agitation of ECCS Check Valves, Salem 1 and Salem 2 Generating Stations, dated 6/17/01
Letter from Valve Engineering Supervisor to Salem OCC, Mechanical Agitation of SJ156 and SJ139 Valves, dated 10/7/01
NOSPA-SA-12-2C, Nuclear Oversight Assessment Report Salem Generating Station May through August 2012, September 26, 2012

NE-97-03462, Letter from Salem Mechanical/Civil Manager to Salem Maintenance Manager, Mechanical Agitation of ECCS Check Valves 21-24SJ43, 21-24SJ55 and 21-24SJ56, Salem Generating Station, Unit 2, dated 7/1/97
NRC Generic letter 87-06: Periodic Verification of Leak Tight Integrity of Pressure Isolation Valves, dated 3/13/87
NRC Generic letter 89-04: Guidance on Developing Acceptable Inservice Testing Programs, dated 4/3/89
NRC Information Notice 97-16: Preconditioning of Plant Structures, Systems, and Components before ASME Code Inservice Testing or Technical Specification Surveillance Testing, dated 9/28/98
NRC Inspection Manual Part 9900: Technical Guidance, Maintenance – Preconditioning of Structures, Systems, and Components Before Determining Operability, dated 4/4/97
NRC NUREG-1482, Guidelines for Inservice Testing at Nuclear Power Plants, Revision 1
Salem Generating Station - Units 1 and 2 Inservice Testing Manual for Pumps and Valves Interval 4 Program, Revision 0
SC.MD-PM.ZZ-0052, Disassembly, Inspection and Reassembly of Velan Swing Check Valves, performed 11/10/11
SC.MD-PM.ZZ-0071, Disassembly, Inspection and Reassembly of Edward Unwelded Check Valve Mark #FA-31 and FA-32 Check Valves, performed 11/2/11 & 10/25/12
SC.MD-PM.ZZ-0075, Disassembly, Inspection and Reassembly of Edward Unwelded Check Valve Mark #FA-35 Check Valve, performed 10/25/12
SC.MD-PM.ZZ-0087, Disassembly, Inspection and Reassembly of 2” Class 1500 Rockwell Edwards Lift Check Mark #FA-146 (21SJ144), performed 10/23/12
SC.MD-PM.ZZ-0087, Disassembly, Inspection and Reassembly of 2” Class 1500 Rockwell Edwards Lift Check Mark #FA-146 (22SJ144), performed 10/24/12
SC.MD-PM.ZZ-0087, Disassembly, Inspection and Reassembly of 2” Class 1500 Rockwell Edwards Lift Check Mark #FA-146 (23SJ144), performed 10/24/12
SC.MD-PM.ZZ-0087, Disassembly, Inspection and Reassembly of 2” Class 1500 Rockwell Edwards Lift Check Mark #FA-146 (24SJ144), performed 10/24/12
SC.MD-PM.ZZ-0120, Disassembly, Inspection and Reassembly of Edward Unwelded Check Valve Mark #'s FA-43, FA-45, FA-92, FA-182, FA-184, FA-186, FA-187, FA-188, FA-189, FA-192 & FA-203 (11SJ17), performed 11/2/11
SC.MD-PM.ZZ-0120, Disassembly, Inspection and Reassembly of Edward Unwelded Check Valve Mark #’s FA-43, FA-45, FA-92, FA-182, FA-184, FA-186, FA-187, FA-188, FA-189, FA-192 and FA-203 (12SJ17), performed 11/3/11
SGS-TRM, Salem Generating Station Units 1 and 2 Technical Requirements Manual, Revision 0
SRE12-001, Salem Unit 2 fuel Reliability Memorandum
SRE12-002, Info for DCS Loading Salem 2 Campaign #1 Fuel Characterization
VLV-98-0002, Letter from Salem Valve Group Supervisor to Plant Maintenance Manager, Mechanical Agitation of ECCS Check Valves, Salem Generating Station, Units 1 and 2, dated 3/5/98
VTD 106252, 6” Swing Check Valve (Velan Drawing No. 78704), Revision 11
VTD 127775, Instruction Manual for Darling Manual Valves, Issue 2
VTD 140285, Instruction Manual for Motor Operated & Manual Valves, Revision 7
Unit 1 and Unit 2 ECCS Check Valve Leakage History, dated 4/18/07 - 11/15/12
Unit 1 Safety Injection System Health Report, Q3-2012
Unit 2 Safety Injection System Health Report, Q3-2012
2012 Salem Operations Department Excellence Plan
Salem Common Station Standing Order, Operations Department Retest, 8/5/12

Salem Common Station Standing Order, Salem Unit 2 Outage Enhanced Control Board Monitoring, 10/15/12
Apparent Cause Evaluation, Tech Spec 3.0.3 Entry for Incorrect Trip Setpoints Installed in 1N35 and 1N36
LER 2011-005-00, Incorrect NIS Trip Setpoints Results in TS 3.0.3 Entry

Section 4OA3: Follow-up of Events and Notices of Enforcement Discretion

Procedures
OP-SA-108-114-1001, Post-Trip Data Collection Guidelines - Salem, Revision 3
OP-AA-108-108, Unit Restart Review, Revision 11
SC.OP-AB.ZZ-0001, Adverse Environmental Conditions, Revision 15

Notifications

20581000	20581001	20581003	20581108	20581071	20581079
20581080	20581091	20581112	20581163	20581257	20581308
20581310	20581208				

Work Orders

70145215	70145413

Other Documents
OTDM S-12-011, 1N31 Source Range Detector Reliability

Section 4OA5: Other Activities

Procedures
MA-AA-796-024, Scaffold Installation, Inspection, and Removal, Revision 11

Notifications (*NRC-identified)

20477765	20574016	20574115	20574136	20574138	20574220
20574407	20574410	20574411	20574412	20574413	20574510
20574511	20574521	20574830	20575862	20576464	20577091
20585541	20568967	20588282*	20585542	20590280*	

Other Documents
1025286, EPRI Seismic Walkdown Guidance for Resolution of Fukushima Near-Term Task Force Recommendation 2.3: Seismic, Jun 2012
A-0-ZZ-SEE-1160, Establishment of Requirements for Monitoring the Condition of Structures, Revision 1
LR-N12-0370, Salem Generating Station Walkdown Report, November 26, 2012
NEI 12-07, Guidelines for Performing Verification Walkdowns of Plant Flood Protection Features, Revision 0-A
S-C-ZZ-SEE-0578, Development of Procedures for Assessment and Evaluation of Deterioration in Concrete Structures Salem Generating Station Units 1 and 2, Revision 0
S-C-ZZ-SEE-1035, Evaluation of Deteriorated Concrete Areas in Plant Structures Salem Generating Station Units 1 and 2, Revision 0
S-C-ZZ-SEE-1143, Evaluation of Seismic Gap Violations, Revision 1
SL-2012-11168, SGS Walkdown Record Forms, Revision 0

LIST OF ACRONYMS

ADAMS	Agencywide Documents Access and Management System
ALARA	as low as reasonably achievable
ASME	American Society of Mechanical Engineers
CAP	corrective action program
CCW	component cooling water
CFR	Code of Federal Regulations
CRDM	control rod drive mechanism
CVC	chemical and volume control
DVR	degraded voltage relay
ECCS	emergency core cooling system
ECT	eddy current testing
EDG	emergency diesel generator
EPD	electronic personal dosimeter
EPRI	Electric Power Research Institute
FME	foreign material exclusion
HRA	high radiation area
HX	heat exchanger
IMC	Inspection Manual Chapter
INPO	Institute of Nuclear Power Operations
IPEEE	Individual Plant Examination for External Events
ISI	in-service inspection
MOV	motor-operated valve
MSHA	Mine Safety and Health Administration
NCV	non-cited violation
NDE	non-destructive examination
NEI	Nuclear Energy Institute
NIOSH	National Institute for Occupational Safety and Health
NRC	Nuclear Regulatory Commission
NVLAP	National Voluntary Laboratory Accreditation Program
ODCM	Offsite Dose Calculation Manual
OOS	out of service
PARS	Publicly Available Records
PDP	positive displacement pump
PM	preventive maintenance
PSEG	Public Service Enterprise Group Nuclear LLC
PT	penetrant testing
RCA	radiological controlled area
RG	Regulatory Guide
RWP	radiation work permit
SDP	Significance Determination Process
SI	safety injection
SSC	structure, system, or component
SSOP	single source of offsite power
SW	service water
TS	Technical Specification
UFSAR	Updated Final Safety Analysis Report
UT	ultrasonic testing
VHRA	very high radiation area
VT	visual inspection