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

May 9, 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 05000272/2013002 AND 05000311/2013002

Dear Mr. Joyce:

On March 31, 2013, 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 April 4, 2013 with Mr. Fricker, Vice President of Salem Operations, 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 and four self-revealing findings of very low safety significance (Green). Three of these findings were determined to involve violations of NRC requirements. However, because of the very low safety significance, and because they are entered into your corrective action program, the NRC is treating these findings as non-cited violations (NCVs), consistent with Section 2.3.2 of the NRC Enforcement Policy. If you contest any NCVs 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's Public Document Room or from the Publicly Available Records component of the NRC's Agencywide Documents Access Management 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/

Glenn T. Dentel, Chief
Reactor Projects Branch 3
Division of Reactor Projects

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

Enclosure: Inspection Report 05000272/2013002 and 05000311/2013002
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.:	05000272/2013002 and 05000311/2013002
Licensee:	PSEG Nuclear LLC (PSEG)
Facility:	Salem Nuclear Generating Station, Units 1 and 2
Location:	P.O. Box 236 Hancocks Bridge, NJ 08038
Dates:	January 1, 2013 through March 31, 2013
Inspectors:	E. Bonney, Acting Senior Resident Inspector P. McKenna, Resident Inspector R. Rolph, Acting Resident Inspector S. Barr, Senior Emergency Preparedness Specialist E. Burket, Emergency Preparedness Specialist J. Laughlin, Emergency Preparedness Specialist
Approved By:	Glenn T. Dentel, Chief Reactor Projects Branch 3 Division of Reactor Projects

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SUMMARY

IR 05000272/2013002, 05000311/2013002; 01/01/2013 - 03/31/2013; Salem Nuclear Generating Station Units 1 and 2; Maintenance Effectiveness and Follow-up of Events and Notices of Enforcement Discretion.

This report covered a three-month period of inspection by resident inspectors and announced inspections performed by regional inspectors. Three non-cited violations (NCVs) and two findings of very low safety significance (Green) were identified. The significance of most findings is indicated by their color (i.e., greater than Green, or Green, White, Yellow, Red) and determined using Inspection Manual Chapter (IMC) 0609, "Significance Determination Process" (SDP), dated June 2, 2011. Cross-cutting aspects are determined using IMC 0310, "Components Within Cross-Cutting Areas," dated October 28, 2011. All violations of NRC requirements are dispositioned in accordance with the NRC's Enforcement Policy, dated January 28, 2013. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG-1649, "Reactor Oversight Process," Revision 4.

Cornerstone: Initiating Events

- Green. A self-revealing finding was identified because the work instructions used to perform relay testing on January 21, 2013, did not include the level of detail required by site work planning standards. Specifically, they did not specify the test switches that needed to be open to isolate the transformer for the testing. This caused the loss of #4 station power transformer (SPT), which caused both units to align the 4160 Vac vital buses to a single source of offsite power and Unit 2 to reduce power to 95 percent when it lost half of its running circulating water pumps. Planned corrective actions include updating relay procedures and reevaluating risk assignment of relay work.

  The performance deficiency was determined to be more than minor because it is associated with the procedure quality attribute of the Initiating Events cornerstone and affected the cornerstone objective to limit the likelihood of those events that upset plant stability and challenge critical safety functions during shut-down as well as power operations. Specifically, PSEG work instructions did not include which test switches were required to be opened prior to testing, which led to the loss of one source of offsite power at each unit and Unit 2 down-powering due to the loss of circulating water pumps. In accordance with IMC 0609.04, "Initial Screening and Characterization," and Exhibit 1 of IMC 0609, Appendix A, "The Significance Determination Process for Findings At-Power," issued June 19, 2012, the inspectors determined that this finding is of very low safety significance (Green) because the performance deficiency did not cause both a reactor trip and the loss of mitigation equipment relied upon to transition the plant from the onset of the trip to a stable shutdown condition. This finding had a cross-cutting aspect in the area of Human Performance, Work Control, because PSEG did not plan and coordinate work activities consistent with nuclear safety. Specifically, PSEG did not incorporate risk insights on the potential impact on offsite power during #4 SPT maintenance. As a result, PSEG did not plan and coordinate work activities to minimize the probability or consequences of a loss of off-site power. [H.3(a)] (Section 1R12)

- Green. A self-revealing finding was identified because PSEG did not implement timely and effective corrective actions to address feedwater control valve (FCV) positioner malfunctions that occurred between 2004 and 2012. The inspectors determined that minor malfunctions between 2007 and 2012 provided PSEG indication that the ability of FCVs to properly respond to plant transients remained adversely affected and that actions completed to date may not have been effective. As a result of PSEG's ineffective and untimely action, on November 25, 2012, Unit 2 tripped from 92 percent power due to a malfunction of FCV 24BF19. Planned corrective actions include replacing the FCV positioners with digital controllers during the next refueling outage at each unit.

  The performance deficiency was determined to be more than minor because it affected the equipment performance attribute of the Initiating Events cornerstone and affected the cornerstone objective to limit the likelihood of events that upset plant stability and challenge critical safety functions during shutdown as well as at power operations. Specifically, the failure of the FCV to reposition as demanded resulted in a low steam generator water level and subsequent plant trip. In accordance with IMC 0609.04 "Initial Screening and Characterization," and Exhibit 1 of IMC 0609, Appendix A, "The Significance Determination Process for Findings At-Power," issued June 19, 2012, the inspectors determined that this finding is of very low safety significance (Green) because the performance deficiency did not cause both a reactor trip and the loss of mitigation equipment relied upon to transition the plant from the onset of the trip to a stable shutdown condition. This finding has a cross-cutting aspect in the area of Human Performance, Decision Making, because PSEG decisions did not demonstrate that nuclear safety was an overriding priority. Specifically, PSEG did not demonstrate conservative assumptions in decision making by postponing corrective actions to prevent recurrence over an eight year time span, despite numerous issues with the feedwater regulating valves that culminated in the plant tripping. [H.1(b)] (Section 4OA3)

Cornerstone: Mitigating Systems

- Green. The inspectors identified an NCV of 10 CFR Part 50, Appendix B, Criterion VII, "Control of Purchased Material, Equipment, and Services," because, PSEG did not assure that replacement zinc anodes procured for the service water (SW) strainers conformed to procurement documents. Specifically, PSEG did not confirm the critical characteristics of the SW replacement zinc anodes before they were installed in the SW system. As a result, a zinc anode that did not meet procurement standards, which was installed in the 11 SW strainer, degraded over time, fell into the strainer and stopped it from rotating. PSEG repaired the strainer and corrected the part procurement code as immediate corrective actions.

  The performance deficiency was determined to be more than minor because it was associated with the equipment performance attribute of the Mitigating Systems cornerstone and it adversely affected the cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. The issue was also similar to IMC 0612, Appendix E, Example 5.c, in that, an incorrect and

inadequate part was installed in 11 SW strainer and the strainer was returned to service. The inspectors evaluated the finding in accordance with IMC 0609, Appendix A, "Determining the Significance of Reactor Inspection Findings for At-Power Situations," and determined that the finding was of very low safety significance (Green) because the deficiency did not affect the design or qualification of the SW system, did not represent a loss of system safety function and did not represent an actual loss of function of a single train for greater than its TS allowed outage time. This finding has a cross-cutting aspect in the area of Human Performance, Resources, because PSEG did not ensure that complete, accurate, and up-to-date design documentation, procedures, and work packages, and correct labeling of components. Specifically, neither the SW strainer maintenance procedure, the strainer design drawing, nor the material master for the SW strainer zinc anode part identified critical dimensions or physical characteristics for the zinc anode that could have been used by technicians to ensure the correct replacement anode was installed in the 11 SW strainer. [H.2(c)] (Section 1R12)

- <u>Green</u>. A self-revealing NCV of Technical Specification (TS) 6.8.1, "Procedures and Programs," was identified because PSEG personnel did not use the documentation required by site procedures to verify component position during removal of a clearance tagout. As a result, on November 4, 2012, PSEG personnel isolated SW to all emergency diesel generators (EDGs) at Unit 2 while in Mode 6 with fuel movement in progress. As corrective actions, PSEG conducted valve line-up training for field operators and initiated additional field oversight of in-plant activities.

  The performance deficiency was determined to be more than minor because it affected the configuration control attribute of the Mitigating Systems cornerstone to ensure the availability, reliability and capability of systems that respond to initiating events to prevent undesirable consequences. Specifically, a SW valve was incorrectly positioned, isolating all cooling water to the EDGs. The inspectors evaluated the finding using IMC 0609.04, "Initial Characterization of Findings," Attachment 1 of IMC 0609, and Appendix G, "Shutdown Operations Significance Determination Process Phase 1 Operational Checklists for Both PWRs and BWRs – Attachment 4 PWR Refueling Operation: RCS level >23' or PWR Shutdown Operation with Time to Boil >2 hours and Inventory in the Pressurizer." Because no loss of control occurred and all mitigating capabilities were available, a Phase 2 quantitative assessment was not required. Therefore, the inspectors determined the finding to be of very low safety significance (Green). This finding had a cross-cutting aspect in the area of Human Performance, Work Practices, in that PSEG did not effectively communicate human error prevention techniques commensurate with the risk of the assigned task. Specifically, the pre-job brief did not enforce the expectation to contact supervision when an unexpected condition was identified, personnel did not perform self checking prior to component manipulation, and personnel proceeded in the face of uncertainty. [H.4(a)] (Section 4OA3)

Cornerstone: Barrier Integrity

- <u>Green</u>. A self-revealing NCV of 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Action," was identified because PSEG did not complete corrective actions to address degraded valve bearings (i.e., installing new bearings) identified by technicians during SW check valve maintenance in 2010. As a result, binding of the valve disk occurred, which allowed silt accumulation to occur on the valve seat, which prevented the check valve from

closing during testing on October 23, 2012. Corrective actions included updating the procedure and ensuring detailed explanations of unsatisfactory conditions that will result in the appropriate use of “mode holds” during outages that ensures completion of significant corrective action items.

The performance deficiency was determined to be more than minor because it affected the containment configuration control attribute of the Barrier Integrity cornerstone and adversely affected the cornerstone objective to provide reasonable assurance that physical design barriers (fuel cladding, reactor coolant system, and containment) protect the public from radionuclide releases caused by accidents or events. Specifically, the failure of the check valve to fully close due to silt accumulation, impacted operability of a containment fan cooling unit (CFCU) SW accumulator, which degraded the affected CFCUs’ cooling water flow, reducing their containment heat removal capacity, which could affect containment integrity if the affected CFCUs were relied upon for containment cooling during an event. In accordance with IMC 0609.04, “Initial Screening and Characterization,” and Exhibit 3 of IMC 0609, Appendix A, “The Significance Determination Process for Findings At-Power,” issued June 19, 2012, the inspectors determined that this finding is of very low safety significance (Green) because the performance deficiency did not represent an actual pathway in the physical integrity of the reactor containment, containment isolation system, or heat removal components. This finding has a cross-cutting aspect in the area of Human Performance, Work Practices, because PSEG did not effectively communicate expectations regarding compliance with procedures. Specifically, PSEG did not install parts required by the internal inspection procedure that led to the check valve being inoperable. [H.4(b)] (Section 1R12)

REPORT DETAILS

Summary of Plant Status

Unit 1 began the inspection period at 100 percent power and remained at or near 100 percent power throughout the inspection period.

Unit 2 began the inspection period at 100 percent power and remained at or near 100 percent power throughout the inspection period.

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, and Barrier Integrity

1R01 Adverse Weather Protection (71111.01 – 1 sample)

Readiness for Impending Adverse Weather Conditions

a. Inspection Scope

The inspectors performed a review of PSEG's readiness for the onset of seasonal high levels of river detritus. The inspectors reviewed PSEG's weather preparation activities related to potential river grass intrusion conditions. The inspectors assessed implementation of PSEG's grassing readiness plan through plant walkdowns, corrective action program review, and discussion with cognizant managers and engineers. Documents reviewed for each section of this inspection report are listed in the Attachment.

b. Findings

No findings were identified.

1R04 Equipment Alignment

.1 Partial System Walkdowns (71111.04 – 3 samples)

a. Inspection Scope

The inspectors performed partial walkdowns of the following systems:

- 12 and 13 component cooling water (CC) pump lineup with 11 CC pump out of service (OOS) on January 4, 2013
- 12 containment spray (CS) pump lineup with 11 CS pump OOS on January 31, 2013
- 12 charging pump lineup with 11 charging pump OOS on March 5, 2013

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 updated final safety analysis report (UFSAR), TSs, work orders, notifications, 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 corrective action program for resolution with the appropriate significance characterization.

b. Findings

No findings were identified.

.2 Full System Walkdown (71111.04S – 1 sample)

a. Inspection Scope

On February 19 and March 4, 2013, the inspectors performed a complete system walkdown of accessible portions of the Unit 1 C EDG and the engineered safety feature actuation system to verify the existing equipment lineups were correct. The inspectors reviewed operating procedures, surveillance tests, drawings, equipment line-up check-off lists, and the UFSAR to verify the system was aligned to perform its required safety functions. The inspectors also reviewed electrical power availability, component lubrication and equipment cooling, hangar and support functionality, and operability of support systems. The inspectors performed field walkdowns of accessible portions of the systems to verify system components and support equipment were aligned correctly and operable. The inspectors examined the material condition of the components and observed operating parameters of equipment to verify that there were no deficiencies. Additionally, the inspectors reviewed a sample of related notifications and work orders to ensure PSEG appropriately evaluated and resolved any deficiencies.

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 were 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 OOS, degraded, or inoperable fire protection equipment, as applicable, in accordance with procedures.

- Unit 1, auxiliary feedwater pump, 84' elevation, on February 1, 2013
- Unit 2, auxiliary feedwater pump, 84' elevation, on February 1, 2013
- Unit 1, fuel handling building, 130' elevation, on February 5, 2013
- Unit 1, SW intake structure, 92' and 112' elevation, on February 5, 2013
- Unit 2, SW intake structure, 92' and 112' elevation, on February 5, 2013

b. Findings

No findings were identified.

1R06 Flood Protection Measures (71111.06 – 1 sample)

Internal Flooding Review

a. Inspection Scope

The inspectors reviewed the UFSAR, the site flooding analysis, and plant procedures to assess susceptibilities involving internal flooding. The inspectors also reviewed the corrective action program to determine if PSEG identified and corrected flooding problems and whether operator actions for coping with flooding were adequate. The inspectors also focused on the Unit 1 EDG room areas to verify the adequacy of equipment seals located below the flood line, floor and water penetration seals, common drain lines and temporary or removable flood barriers.

b. Findings

No findings were identified.

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

.1 Quarterly Review of Licensed Operator Requalification Testing and Training

a. Inspection Scope

The inspectors observed licensed operator simulator training on March 19, 2013, which included an anticipated transient without a trip, a loss of coolant accident and the failure of select 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 the Unit 2 2C main power transformer temporary modification, classified as an infrequent plant activity, on February 21, 2013 and the Unit 2 calibration of the 21 steam generator narrow range level transmitter on March 27, 2013. The inspectors observed pre-shift briefings and reactivity control briefings to verify that the briefings met the criteria specified in procedure HU-AA-1211, “Pre-job Briefings.” Additionally, the inspectors verified that procedure use, crew communications, and coordination of activities between work groups similarly met established expectations and standards.

b. Findings

No findings were identified.

1R12 Maintenance Effectiveness (71111.12Q – 2 samples)

a. Inspection Scope

The inspectors reviewed the samples listed below to assess the effectiveness of maintenance activities on structure, system, and component (SSC) performance and reliability. The inspectors reviewed system health reports, corrective action program 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. For each sample selected, 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. As applicable, for SSCs classified as (a)(1), the inspectors assessed the adequacy of goals and corrective actions to return these SSCs to (a)(2). Additionally, the inspectors ensured that PSEG staff was identifying and addressing common cause failures that occurred within and across maintenance rule system boundaries.

- 11 SW strainer 3-year periodic maintenance during the week of January 21, 2013
- Unit 2 FCV performance during the week of February 4, 2013

b. Findings

1. Introduction: A self-revealing Green NCV of 10 CFR Part 50, Appendix B, Criterion XVI, “Corrective Action,” was identified because PSEG did not complete corrective actions to address degraded valve bearings (i.e., installing new bearings) identified by technicians during SW check valve 11SW536 valve maintenance in 2010. As a result, binding of the valve disk occurred, which allowed silt accumulation to occur on the valve seat, which prevented the check valve from closing during testing on October 23, 2012.

Description: During an accident, CFCUs provide heat removal from the containment. The heat sink for these units is the SW system. Each unit is equipped with a normally isolated SW accumulator. The purpose of these accumulators is to maintain CFCU SW

piping solid following a loss of offsite power. Each CFCU SW accumulator has a check valve that has a safety function in the open and closed position. The check valve is required to remain closed during conditions other than a loss of offsite power to prevent diversion of SW from the CFCUs to the accumulators. During a loss of offsite power, the valve is required to open to maintain SW to the CFCUs. A failure of the check valve in the reverse flow direction would result in a loss of function of the CFCUs, because it would starve cooling water flow to the CFCU during accidents that do not include a loss of offsite power.

On October 23, 2012, during S1.OP-ST.SW-0015, “In-Service Test of the Service Water System CFCU Accumulator Check Valves,” 11SW536 check valve failed the reverse flow portion of the surveillance test. In response, operators immediately completed all required TS action statement actions for the loss of the two CFCU SW accumulators whose service water cooling flow was affected by the valve failure. The 11SW536 check valve was repaired and the system was returned to its normal line-up on October 24 within the TS allowed outage time requirements.

On October 24, 2012, PSEG completed an internal inspection of 11SW536 per SC.MD-PM.ZZ-0123, “Disassembly, Inspection and Reassembly of Dual Plated Check Valves.” The inspection identified silt buildup on the upstream side of the check valve, which prevented the valve plates from properly seating. The internal inspection identified four body lug bearings missing, which caused the valve plates to bind and stick. Body lug bearings allow for even distribution of compression in the check valve hinges. Without the body lug bearings installed, over a two year time period, degradation of the valve internals occurred resulting in the valve improperly seating during the quarterly reverse flow test. Failure of the valve to seat 1/8” off the valve seat allowed silt to accumulate and prevented the valve from fully closing.

PSEG’s apparent cause evaluation identified that the valve was previously disassembled on April 14, 2010, when an internal inspection of 11SW536 check valve was performed. The inspection documented that the as-found condition of the bearings in the check valve was unsatisfactory; however, Work Order 50104557 noted that 11SW536 passed the post maintenance test, a valve stroke test. No documentation of the specific unsatisfactory condition of the bearings or how that condition was corrected was identified. The procedure used to perform the maintenance in 2010 did not direct the actions required to correct the condition and PSEG did not identify a notification written as a result of the identified unsatisfactory condition of the bearings. A task in work order 50104557 stated that no new internal parts were used in the reassembly and no documentation of body lug bearing replacement was identified. Therefore, based on the 2012 surveillance test failure and subsequent internal inspection results, the inspectors concluded that the unsatisfactory body lug bearing issue identified in 2010 was not adequately addressed. Available documentation for the 2010 maintenance indicated that 11SW536 was reassembled without all of the required parts and then returned to service. The history showed that although technicians identified the bearings as unsatisfactory and three new bearings and two gaskets were removed from the warehouse for the repair, the final work order status indicated that disassembly/repair of the valve was not required and the parts from the warehouse were not used.

PSEG entered the issue into their corrective action program under notification 20580117 on October 23, 2012. An extent of condition evaluation for the other CFCU SW accumulator check valves was performed, and ultrasonic testing confirmed that no silt

accumulation was present in the other check valves. PSEG updated the internal inspection procedure SC.MD-PM.ZZ-0123 to require a detailed explanation of any unsatisfactory conditions identified during the inspection. A notification of uncorrected conditions should be written, which requires a senior reactor operator review for operability concerns and the use of "mode holds" during outages to ensure completion of significant corrective action items.

Analysis: The inspectors determined that PSEG maintenance personnel did not correct a condition adverse to quality, degraded body lug bearings, which was identified during preventative maintenance performed on SW valve 11SW536 in April 2010. This resulted in the same valve failing a reverse flow surveillance test on October 23, 2012. The inspectors determined that this was a performance deficiency within PSEG's ability to foresee and correct, and should have been prevented. The performance deficiency was determined to be more than minor because it affected the containment configuration control attribute of the Barrier Integrity cornerstone objective to provide reasonable assurance that physical design barriers (fuel cladding, reactor coolant system, and containment) protect the public from radionuclide releases caused by accidents or events. Specifically, the failure of 11SW536 to fully close due to silt accumulation, impacted operability of a CFCU SW accumulator, which degraded the affected CFCUs' cooling water flow, reducing their containment heat removal capacity, which could affect containment integrity if the affected CFCUs were relied upon for containment cooling during an event.

In accordance with IMC 0609.04, "Initial Screening and Characterization," and Exhibit 3 of IMC 0609, Appendix A, "The Significance Determination Process for Findings At-Power," issued June 19, 2012, the inspectors determined that this finding is of very low safety significance (Green) because the performance deficiency did not represent an actual pathway in the physical integrity of the reactor containment, containment isolation system, or heat removal components.

This finding has a cross-cutting aspect in the area of Human Performance, Work Practices, in that PSEG did not effectively communicate expectations. Specifically, PSEG failed to install parts required by the internal inspection procedure that led to the 11SW536 valve being inoperable [H.4(b)].

Enforcement: 10 CFR 50, Appendix B, Criterion XVI, "Corrective Actions," requires, in part, that conditions adverse to quality, such as deficiencies, are promptly identified and corrected. Contrary to the above, PSEG did not promptly correct a condition adverse to quality associated with the SW system. Specifically, PSEG did not correct the degraded check valve bearings technicians identified in service water check valve 11SW536 during preventative maintenance on April 14, 2010, and subsequently the check valve failed reverse flow testing on October 23, 2012. Because this deficiency is considered to be of very low safety significance (Green) and was entered into the corrective action program as notification 20580117, this violation is being treated as a NCV, consistent with Section 2.3.2 of the NRC Enforcement Policy. **(NCV 0500272/2013002-01, Failure to Correct Condition Adverse to Quality in Service Water Check Valve)**

2. Introduction: The inspectors identified a Green NCV of 10 CFR Part 50, Appendix B, Criterion VII, "Control of Purchased Material, Equipment, and Services," because, PSEG did not assure that replacement zinc anodes procured for the SW strainers conformed to procurement documents. Specifically, PSEG did not confirm the critical characteristics

of the SW replacement zinc anodes before they were installed in the SW system. As a result, a zinc anode that did not meet procurement standards, which was installed in the 11 SW strainer, degraded over time, fell into the strainer and stopped it from rotating.

Description: On October 29, 2012, approximately two hours after Hurricane Sandy made landfall in New Jersey, the 11 SW strainer drive motor breaker tripped on thermal overload. Salem entered TS 3.7.4.1, a 72 hour limiting condition for operation (LCO), because the 11 SW pump was the lead "C" bus vital pump. The LCO was exited 10 minutes later when the 12 SW pump was started and the 125 volts direct current (Vdc) control power was removed from the 11 SW pump.

While investigating the cause of the tripped breaker, PSEG's attempts to manually rotate the 11 SW strainer drum were unsuccessful. Further inspection identified that one of the six zinc body anodes and associated bolting attached to the strainer body hand hole had come loose and jammed the strainer drum, preventing it from rotating. There are ten zinc anodes installed inside the 11 SW strainer, six on the body and four on the drum.

PSEG conducted an apparent cause evaluation and identified by visual inspection that the dislodged zinc anode was different in appearance and style than the other nine installed zinc anodes. Specifically, the retaining hole in the center of the zinc had a larger diameter that allowed the zinc anode to spin in place during pump operation. A visual inspection of the retaining stud showed that the center area of the stud was significantly worn and that there were grinding marks on the side of the nut secured to the zinc anode. Based on these observations, PSEG determined that the zinc anode had spun in place over a period of time and eventually loosened the retaining nut and stud from the strainer body. This allowed the zinc to fall off and jam in the strainer. PSEG reviewed the work orders of the 11 SW strainer and determined that the zinc anodes were last replaced on October 17, 2011. PSEG also noted that the zinc anodes were classified as purchase class (PC) 4 and that PC4 procurement items do not have a quality assurance receipt inspection performed when they are received from the vendor.

PSEG contacted the strainer vendor who stated that the zinc anodes installed in the SW strainers should have a 0.5 inch diameter center hole with a metal insert to prevent corrosion and loosening. Inspection of the 11 SW zinc anode that fell off identified that it had a center hole that was larger than 0.5 inch and also did not have a metal insert. A review of the in-stock zincs from the same vendor found that 21 of 22 in stock anodes had the 0.5 inch correct center hole dimension, but all were missing the metal insert. As such, PSEG concluded that the apparent cause of the 11 SW strainer failure to rotate on October 29, 2012, was that a zinc anode that did not meet design specifications was supplied by the vendor, installed in the strainer, corroded over time and then fell off jamming the strainer.

The inspectors reviewed all PSEG documentation associated with the procurement, maintenance (installation and replacement), and design of the zinc anodes used in the Salem SW strainers. None of the documentation reviewed identified critical dimensions or critical physical characteristics for the anode center hole dimension or metal insert. The documentation reviewed included the SW strainer maintenance procedure, SC.MD-PM.SW-003; the strainer design drawing, VTD 304931; and the material master for the SW strainer zinc anode part, x377189. The inspectors also reviewed PSEG procedure SM-AA-3000-1001, "Procurement Activities and Responsibilities," to verify the procurement classification code for the zinc anodes used in the SW strainers. The

procurement classification code determines the type of receipt inspection performed. PSEG's procedure stated that an item assigned a classification code of PC4 was one whose failure would not impact the function of important to safety components or systems, while a PC3 classification was assigned to non-safety related items that required PSEG quality assurance involvement because of their potential to impact safety equipment. As stated above, PSEG had classified the SW strainer zinc anodes as PC4. The inspectors determined that due to the size and location of the zinc anodes installed in the SW strainer rotating drum assemblies, it was reasonable to conclude that the failure of a zinc anode (i.e., falling off) could impact the strainer's function and, therefore, the PC3 procurement classification code was the appropriate procurement code. This would have required a quality check of the zinc anode when it was received at PSEG; which would have verified that the received component had the dimensions and physical characteristics required to meet its design before it was installed in a safety-related component. The inspectors determined that had this type of receipt inspection been completed for the zinc anode that failed, or had the procedure used to install the zinc anode directed technicians to confirm critical dimensions or characteristics of the replacement anode, it was reasonable to conclude that the faulty anode would not have been installed into the system. NRC inspectors identified that the zinc anodes were incorrectly coded PC4 and that critical dimensions were not included in the work package to install the zinc anodes.

As immediate corrective actions for the failed SW strainer, PSEG completed repairs to the SW strainer included replacing the failed zinc anode with a correctly sized zinc anode. The 11 SW strainer was returned to operable status at 4:02 a.m. on November 3, 2012. The 11 SW strainer was unavailable for 4 days and 5.5 hours due to the zinc anode failure. The other SW strainers have been inspected for correct parts. PSEG entered the issue into their corrective action program as notification 20581163.

<u>Analysis</u>: The inspectors determined not conducting a quality check and not having documentation available for zinc anode critical characterictics, resulted in not conforming to SW strainer procurement standards. This was a performance deficiency that was within PSEG's ability to foresee and correct. The performance deficiency was determined to be more than minor because it is associated with the equipment performance attribute of the Mitigating Systems cornerstone, and it adversely affected the cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. The issue is also similar to IMC 0612, Appendix E, Example 5.c, in that, an incorrect and inadequate part was installed in the 11 SW strainer and the strainer was returned to service. Specifically, PSEG did not assign the proper procurement code to the SW replacement zincs in accordance with PSEG procedure SM-AA-3000-1001, "Procurement Activities and Responsibilities." This prevented the zincs from receiving the detailed receipt inspection intended to identify material deficiencies before procured material is installed in its associated system. As a result, a zinc anode that did not meet procurement standards, which was installed in the 11 SW strainer, degraded over time, fell into the strainer and stopped it from rotating. The inspectors evaluated the finding in accordance with IMC 0609, Appendix A, "Determining the Significance of Reactor Inspection Findings for At-Power Situations" (IMC 0609A). The inspectors determined that the finding was of very low safety significance (Green) because the deficiency did not affect the design or qualification of the SW system, did not represent a loss of system safety function, and did not represent an actual loss of function of a single train for greater than its TS allowed outage time.

This finding has a cross-cutting aspect in the area of Human Performance, Resources component, because PSEG did not ensure that complete, accurate, and up-to-date design documentation, procedures, and work packages, and correct labeling of components. Specifically, neither the SW strainer maintenance procedure, SC.MD-PM.SW-003; the strainer design drawing, VTD 304931; nor the material master for the SW strainer zinc anode part, x377189, identified critical dimensions or physical characteristics for the zinc anode that could have been used by technicians to ensure the correct replacement anode was installed in the 11 SW strainer. [H.2(c)]

Enforcement: 10 CFR Part 50, Appendix B, Criterion VII, "Control of Purchased Material, Equipment, and Services," requires in part, that measures shall be established to assure that purchased material, equipment, and services, whether purchased directly or through contractors and subcontractors, conform to the procurement documents. Contrary to the above, PSEG did not assure that replacement zinc anodes procured for the SW strainers conformed to the procurement documents. Specifically, PSEG did not confirm the critical characteristics of the SW replacement zinc anodes before they were installed in the SW system. Subsequently, a zinc anode installed in the 11 SW strainer that did not conform to the procurement standards, degraded over time, fell into the strainer and stopped it from rotating. This made the 11 SW strainer inoperable and required operators to take action in accordance with TS to compensate for the damaged safety-related equipment. Because this issue is of very low safety significance (Green) and was entered into the corrective action program as notification 20581163, this finding is being treated as an NCV, consistent with Section 2.3.2 of the NRC Enforcement Policy. **(NCV 0500272/2013002-02, Failure to Install the Correct Size Zinc Anode in 11 Service Water Strainer Results in Strainer Trip)**

3. Introduction. A self-revealing Green finding was identified because the work instructions used to perform relay testing on January 21, 2013, did not include the level of detail required by site work planning standards. Specifically, they did not specify the test switches that needed to be open to isolate the transformer for the testing. This caused the loss of #4 SPT, which caused both units to align the 4160 Vac vital buses to a single source of offsite power and Unit 2 to reduce power to 95 percent when it lost half of its running circulating water pumps.

   Description. The #4 SPT is located in the Salem switchyard, and provides a source of offsite power to Unit 1 and Unit 2. The #4 SPT has protective relays installed that prevent damage to the equipment, and the relays require periodic testing to ensure protective features work as expected. The ground detection relays are tested by isolating the circuit though opening test switches, then inputting a test signal to determine if the relay would isolate the transformer. If all of the test switches in the circuit are not opened, the test signal is seen as a valid ground signal by the relay, and breakers in the switchyard will automatically open to prevent a fault from damaging equipment. When the #4 SPT is isolated, that source of offsite power is removed from service and no longer available to power safety related 4160 Vac vital buses. Portions of the safety-related 4160 Vac buses and half of the circulating water pumps are affected by the power loss. The safety-related buses automatically transfer to the alternate source of power; however, the circulating water pumps must be manually restarted.

On January 21, 2013 at 2:16 p.m., Salem Station experienced a loss of the #4 SPT during ground detection relay testing of the transformer. In response operators at both units entered the abnormal operating procedures for circulating water system malfunction and partial loss of off-site power. The loss caused both units to align the 4160 Vac vital buses to a single source of offsite power and Unit 2 reduced power to 95 percent due to a loss of half of that unit's circulating water pumps. The #4 SPT was returned to service at 11:00 p.m. on January 21, 2013, after PSEG concluded that a human performance error caused the transformer isolation.

PSEG reviewed the circumstances that led to the loss of the #4 SPT and determined that PSEG technicians did not properly isolate the relays during the testing of the 86-4GR grounding relay on the #4 SPT. The technicians documented in the relay testing procedure that they reviewed the drawings and opened all test switches for the relay, but no specific listing of switches was made during the technicians' review of the drawings. A review of the system alignment in the field determined that only one of the two test switches (TS2) that needed to be opened for the testing was opened. As a result, when the test signal was introduced, the switch that was left closed in error (TS1) introduced the grounding signal to the #4 SPT protection circuitry and isolated the transformer. As a result of the transformer isolation, one of two off-site power sources at Salem was removed from service and operators declared that source inoperable at 2:16 p.m. on January 21, 2013, in accordance with TS.

PSEG determined that the work instructions in work order 30189190 did not identify which test switches needed to be opened to prepare for testing. Instead technicians were directed by the instructions to review the six drawings listed in the work order to determine the switches to be used to isolate the protective circuitry. In addition the instructions used a generic relay test procedure rather than specific detailed instructions to perform the work.

PSEG procedure MA-AA-716-010-1009, "Written Work Instruction for Planners," defined a Level 1, Detailed Work Package, as a work package for non-routine tasks that were fairly complex and performed infrequently. It further stated that if, due to the complexity of the work, detailed instructions were needed but not available in existing instructions or procedures, they should be communicated to the craft in the work package if the work presents a high risk of lost generation, entry into an LCO, trip of the unit/generator, personnel safety, or radiological exposure. The inspectors determined that, because the relay testing represented a risk for entry into an LCO or trip of the unit/generator due to the potential loss of one or more circulating water pumps if the maintenance was performed incorrectly, the work instructions used to perform the relay testing on #4 SPT on January 21, 2013, did not comply with this standard.

PSEG entered the issue into the corrective action program under notification 20592250 and 20594628. Work by the distribution relay group was stopped until more specific work instructions could be written. PSEG also determined that the internal risk assessment associated with the relay testing of the #4 SPT had not been screened correctly, in accordance with WC-AA-105, "Work Activity Risk Management." The screening should have assessed the risk as a potential high production risk activity, based on the system energy (13 kilovolts) and location in the switchyard, which implements review of the work package for adequacy of instructions and additional oversight during the maintenance. Higher risk work requires more detailed work

instructions, to reduce potential impact of the work on the station. PSEG is in the process of reviewing the risk assessments for other relay work performed in the switchyard.

Analysis. The inspectors determined that not providing detailed work instructions for #4 SPT relay testing, which adhered to the site's work planning standards, was a performance deficiency reasonably within the licensee's ability to foresee and correct and should have been prevented. The performance deficiency was determined to be more than minor because it is associated with the procedure quality attribute of the Initiating Events cornerstone and directly affected the cornerstone objective to limit the likelihood of those events that upset plant stability and challenge critical safety functions during shut-down as well as power operations. Specifically, PSEG work instructions did not include which test switches were required to be opened prior to testing, which led to the loss of one source of offsite power at each unit and Unit 2 down powering due to the loss of circulating water pumps. In accordance with IMC 0609.04, "Initial Screening and Characterization," and Exhibit 1 of IMC 0609, Appendix A, "The Significance Determination Process for Findings At-Power," issued June 19, 2012, the inspectors determined that this finding is of very low safety significance (Green) because the performance deficiency did not cause both a reactor trip and the loss of mitigation equipment relied upon to transition the plant from the onset of the trip to a stable shutdown condition.

This finding had a cross-cutting aspect in the area of Human Performance, Work Control, because PSEG did not plan and coordinate work activities consistent with nuclear safety. Specifically, in accordance with site work planning standards, PSEG did not incorporate risk insights on the potential impact on offsite power during #4 SPT maintenance. As a result, PSEG did not plan and coordinate work activities to minimize the probability or consequences of a loss of off-site power. [H.3(a)]

Enforcement. This finding does not involve enforcement action because no violation of a regulatory requirement was identified. Because this finding does not involve a violation and is of very low safety significance, it is identified as a finding. **(FIN 05000272, 311/2013002-03, Inadequate Relay Testing Instructions Cause Loss of One Offsite Power Source)**

1R13 Maintenance Risk Assessments and Emergent Work Control (71111.13 – 5 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 TS requirements

and inspected portions of redundant safety systems, when applicable, to verify risk analysis assumptions were valid and applicable requirements were met.

- Planned maintenance on power operated relief valve (PORV) block valve 1PS-7 on January 9, 2013
- Corrective maintenance on the 2A 125 Vdc battery on January 11, 2013
- Planned PORV (1PR-1 and 1PR-2) restoration and leakage monitoring on January 15, 2013
- Emergent elevated risked due to the loss of #4 SPT on January 21, 2013
- Emergent elevated risk due to the failure of 13 switchgear penetration area ventilation (SPAV) fan during planned maintenance on the 12 SPAV fan on February 4, 2013

b. Findings

No findings were identified.

1R15 Operability Determinations and Functionality Assessments (71111.15 – 4 samples)

a. Inspection Scope

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

- 2A 125 Vdc battery cell 36 inspection on January 8, 2013
- 23 chiller high vibrations on January 23, 2013
- 1C EDG air start system start time trending towards TS limit on February 19, 2013
- 700-2K and 700-2J air leaks affecting operation of auxiliary feedwater to steam generator level control valves on March 11, 2013

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.

1R19 Post-Maintenance Testing (71111.19 – 4 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.

- 2A 125 Vdc battery cell 36 replacement on January 11, 2013
- 2C safeguard equipment control sequencer emergent card replacement on January 22, 2013
- 2R45 plant vent noble gas high range process radiation monitor on February 25, 2013
- 2N43 power range nuclear instrument meter and switch replacement on March 13-14, 2013

b. Findings

No findings were identified.

1R22 Surveillance Testing (71111.22 – 6 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:

- S1.OP-ST.DG-0001, 1A EDG surveillance test on January 3, 2013
- S2.OP-ST.CVC-0003, Inservice Testing – 21 charging pump on January 5, 2013 (in-service test)
- S1.OP-ST.RC-0008, Reactor Coolant System (RCS) Inventory Balance for the week of January 14, 2013 (leak rate)
- SC.RE-ST.ZZ-0007, Moderator Temperature Coefficient Measurement on February 10, 2013
- S2.OP-ST.SW-0001, Inservice Testing – 21 SW Pump on March 20, 2013 (in-service test)
- S2.IC-SC.RCP-0034, 2LT-518 #21 Steam Generator Level Protection Channel III on March 27, 2013

b. Findings

No findings were identified.

Cornerstone: Emergency Preparedness

1EP2 Alert and Notification System Evaluation (71114.02 - 1 sample)

a. Inspection Scope

An onsite review was conducted to assess the maintenance and testing of the Alert and Notification System (ANS). During this inspection, the inspectors conducted a review of the ANS testing and maintenance programs. The inspectors reviewed the associated ANS procedures and the Federal Emergency Management Agency approved ANS Design Report to ensure compliance with design report commitments for system maintenance and testing. The inspection was conducted in accordance with NRC Inspection Procedure 71114, Attachment 2. 10 CFR 50.47(b)(5) and the related requirements of 10 CFR Part 50, Appendix E, were used as reference criteria.

b. Findings

No findings were identified.

1EP3 Emergency Response Organization Staffing and Augmentation System (71114.03 - 1 sample)

a. Inspection Scope

The inspectors conducted a review of the Salem Emergency Response Organization (ERO) augmentation staffing requirements and the process for notifying and augmenting the ERO. The review was performed to verify the readiness of key PSEG staff to respond to an emergency event and to verify PSEG's ability to activate their emergency response facilities (ERFs) in a timely manner. The inspectors reviewed the PSEG Emergency Plan for ERF activation and ERO staffing requirements, the ERO duty roster, applicable station procedures, augmentation test reports, the most recent drive-in drill report, and corrective action reports (notifications) related to this inspection area. The inspectors also reviewed a sample of ERO responder training records to verify training and qualifications were up to date. The inspection was conducted in accordance with NRC Inspection Procedure 71114, Attachment 3. 10 CFR 50.47(b)(2) and related requirements of 10 CFR Part 50, Appendix E, were used as reference criteria.

b. Findings

No findings were identified.

1EP4 Emergency Action Level and Emergency Plan Changes (71114.04 - 1 sample)

a. Inspection Scope

NRC staff from the Office of Nuclear Security and Incident Response performed an in-office review of the latest revisions of various Emergency Plan Implementing Procedures

and the Emergency Plan located under ADAMS accession number ML123250117 and ML12348A140 as listed in the Attachment.

PSEG determined that in accordance with 10 CFR 50.54(q), the changes made in the revisions resulted in no reduction in the effectiveness of the Emergency Plan, and that the revised Emergency Plan continued to meet the requirements of 10 CFR 50.47(b) and Appendix E to 10 CFR Part 50. The NRC review was not documented in a safety evaluation report and did not constitute approval of PSEG-generated changes; therefore, this revision is subject to future inspection.

b. Findings

No findings were identified.

1EP5 Maintaining Emergency Preparedness (71114.05 - 1 sample)

a. Inspection Scope

The inspectors reviewed a number of activities to evaluate the efficacy of PSEG's efforts to maintain the Salem emergency preparedness (EP) program. The inspectors reviewed: memorandums of understanding with offsite agencies; the 10 CFR 50.54(q) Emergency Plan change process and practice; PSEG maintenance of equipment important to EP; records of evacuation time estimate population evaluation; and provisions for, and implementation of, primary, backup, and alternate ERF maintenance. The inspectors also verified PSEG's compliance at Salem with new NRC EP regulations regarding: emergency action levels for hostile action events; protective actions for onsite personnel during events; emergency declaration timeliness; ERO augmentation and alternate facility capability; evacuation time estimate updates; on-shift ERO staffing analysis; and ANS back-up means.

The inspectors further evaluated PSEG's ability to maintain their EP program through their identification and correction of EP weaknesses, by reviewing a sample of drill reports, actual event reports, self-assessments, 10 CFR 50.54(t) audits, and EP-related notifications. The inspectors reviewed a sample of EP-related notifications initiated at Salem from March 2011 through March 2013. The inspection was conducted in accordance with NRC Inspection Procedure 71114.05. 10 CFR 50.47(b) and the related requirements of 10 CFR Part 50, Appendix E, were used as reference criteria.

b. Findings

No findings were identified.

1EP6 Drill Evaluation (71114.06 – 1 sample)

Training Observation

a. Inspection Scope

The inspectors observed a simulator training evolution for Unit 2 licensed operators on March 19, 2013, which required emergency plan implementation by an operations crew. PSEG planned for this evolution to be evaluated and included in performance indicator

data regarding drill and exercise performance. The inspectors observed event classification and notification activities performed by the crew. The inspectors also attended the post-evolution critique for the scenario. The focus of the inspectors' activities was to note any weaknesses and deficiencies in the crew's performance and ensure that PSEG evaluators noted the same issues and entered them into the corrective action program.

b. Findings

No findings were identified.

4. OTHER ACTIVITIES

4OA1 Performance Indicator Verification (71151)

.1 Safety System Functional Failures (2 samples)

a. Inspection Scope

The inspectors sampled PSEG's submittals for the Safety System Functional Failures performance indicator for both Unit 1 and Unit 2 for the period of January 1, 2012, through December 31, 2012. To determine the accuracy of the performance indicator data reported during those periods, inspectors used definitions and guidance contained in Nuclear Energy Institute (NEI) Document 99-02, "Regulatory Assessment Performance Indicator Guideline," Revision 6, and NUREG-1022, "Event Reporting Guidelines 10 CFR 50.72 and 10 CFR 50.73." The inspectors reviewed PSEG's operator narrative logs, operability assessments, maintenance rule records, condition reports, event reports and NRC integrated inspection reports to validate the accuracy of the submittals.

b. Findings

No findings were identified.

.2 RCS Specific Activity and RCS Leak Rate (4 samples)

a. Inspection Scope

The inspectors reviewed PSEG's submittal for the RCS specific activity and RCS leak rate performance indicators for both Unit 1 and Unit 2 for the period of January 1, 2012, through December 31, 2012. To determine the accuracy of the performance indicator data reported during those periods, the inspectors used definitions and guidance contained in NEI Document 99-02, "Regulatory Assessment Performance Indicator Guideline," Revision 6. The inspectors also reviewed RCS sample analysis and control room logs of daily measurements of RCS leakage, and compared that information to the data reported by the performance indicator. Additionally, the inspectors observed surveillance activities that determined the RCS identified leakage rate and chemistry personnel acquiring and analyzing an RCS sample.

b. Findings

No findings were identified.

.3 Emergency Preparedness (3 samples)

a. Inspection Scope

The inspectors reviewed data for the following EP performance indicators:

- Drill and Exercise Performance
- ERO Drill Participation
- ANS Reliability

The last NRC EP inspection at Salem was conducted in the second calendar quarter of 2012. Therefore, the inspectors reviewed supporting documentation from EP drills and equipment tests from the second calendar quarter of 2012 through the fourth calendar quarter of 2012 to verify the accuracy of the reported performance indicator data. The review of the performance indicators was conducted in accordance with NRC Inspection Procedure 71151. The acceptance criteria documented in NEI 99-02, "Regulatory Assessment Performance Indicator Guidelines," Revision 6, was used as reference criteria.

b. Findings

No findings were identified.

4OA2 Problem Identification and Resolution (71152 – 1 sample)

.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 corrective action program 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 corrective action program and periodically attended condition report screening meetings.

b. Findings

No findings were identified.

.2 Annual Sample: 28 Vdc and 125 Vdc Battery System Performance

a. Inspection Scope

The inspectors performed an in-depth performance review of PSEG's Unit 1 and Unit 2 28 Vdc and 125 Vdc batteries. Specifically, inspectors reviewed battery maintenance scope, frequency of testing, and overall battery performance to assess PSEG's battery monitoring program. The inspectors reviewed notifications documented in the corrective action program from 2010 to 2013 on 28 Vdc and 125 Vdc batteries. The inspectors assessed the effectiveness of corrective actions for the notifications. In addition, the inspectors interviewed engineering personnel to assess the effectiveness of the battery monitoring program.

b. Findings and Observations

No findings were identified.

The inspectors reviewed the performance of the Unit 1 and Unit 2 safety-related batteries due to the large number of notifications documenting issues with the performance of the batteries. Each unit has two 28 Vdc batteries and three 125 Vdc batteries. The batteries are C&D Technology batteries with an expected 17-year useful service life. The oldest batteries onsite have been in service for 14 years, with replacements planned in 2013 (28 Vdc) and 2014 (125 Vdc). Capacity testing and performance testing data indicate the batteries are capable of performing their required safety function. Inspectors also reviewed PSEG's long term replacement plan for aging batteries.

A significant portion of battery related notifications in the corrective action program involved battery cell specific gravity and lid cracks. In discussions with the system engineer, regular monitoring of the battery is performed by maintenance on a weekly and monthly inspection, in addition to routine engineering system walk downs. Battery cells are inspected for cracking of the cell lids, a known issue with C&D Technology battery cell lids manufactured between 1999 and 2009. Six 125 Vdc and three 28 Vdc batteries onsite manufactured between 1999 and 2009 exhibited lid cracking. Battery cell lids experience hairline fractures in the cell lids that over time progress into cracks that require repair using a vendor approved material to seal the cracks. The repair sealant on the lids and continuous ventilation of the room mitigate potential hydrogen buildup in the battery rooms during a battery discharge. In addition the inspectors confirmed that the fan that provides ventilation for the room alarms in the control room if ventilation is secured. This allows operators to take prompt action to address lost ventilation that could result in excessive hydrogen build-up due to cell cracking.

The inspectors reviewed specific gravity data for the 125 Vdc and 28 Vdc batteries, including technical evaluation 70137178, dated July 31, 2012. This evaluation discussed high specific gravities observed in 13 of 60 battery cells during surveillance test, SC.MD-ST.125-0003, "Quarterly Inspection and Preventive Maintenance of Units 1, 2 and 3 125 Volt Station Batteries." The specific gravity in the cells remained above the TS required minimum value and there is no TS upper limit on specific gravity. The inspectors verified that battery performance data was acceptable and that the higher than expected specific gravity levels did not negatively impact the last performance test and capacity test.

On December 30, 2012, during SC.MD-ST.125-0005, "Annual Inspection and Surveillance of Unit 1 and 2 125 Volt Vital Batteries," maintenance personnel identified a bulged cell post on the 2A 125 Vdc battery cell 36 that resulted in an online cell

replacement. The location of the post bulge did not affect the post's connection to the bus bar, cell 36's connection resistance (28 micro-ohms) was below the limit of 150 micro-ohms, and was consistent with the other 2A 125 Vdc cell resistances. An operability evaluation was completed on January 8, 2013, discussing the ability of the operable but degraded status of the cell. The cell was replaced on January 11, 2013. The inspectors observed the bulged post on cell 36 and the cell replacement. Inspectors determined that adequate plans to ensure operability and long term care of the batteries are in place. PSEG's corrective action program appropriately addressed issues identified with the safety related 128 Vdc and 28 Vdc batteries.

4OA3 Follow-Up of Events and Notices of Enforcement Discretion (71153 – 3 samples)

.1 (Closed) Licensee Event Report (LER) 05000311/2012-004-00: Isolation of Service Water to the Emergency Diesel Generators While in Mode 6

a. Inspection Scope

On November 4, 2012, Unit 2 isolated both SW headers to the EDG credited for TS 3.8.1.2. The operator isolated the incorrect header, resulting in all EDGs being inoperable for approximately five minutes while in Mode 6 during fuel movement. The control room received an alarm that alerted the control room operators of the valve closure and the valve was immediately ordered open by the control room. The control room had remote capability to open the valve if needed, but did not reposition the valve due to personnel safety concerns. The inspectors completed a review of this LER and identified one violation of regulatory requirements. This LER is closed.

b. Findings

Introduction: A self-revealing Green NCV of TS 6.8.1, "Procedures and Programs," was identified because PSEG personnel did not use the documentation required by site procedures to verify component position during removal of a clearance tagout. As a result on November 4, 2012, PSEG personnel isolated SW to all EDGs at Unit 2 while in Mode 6 with fuel movement in progress.

Description: Cooling water flow for the Unit 2 EDGs is supplied by two 100 percent capacity SW headers. In mode 6 only one header is required to be operable to consider the EDGs operable. With all SW flow to the EDGs isolated, the EDGs cannot perform their required safety function.

On November 4, 2012, Unit 2 was in Mode 6 with fuel movement in progress, when, as part of restoration from maintenance, a field operator was directed to remove clearance tags from the 22 SW isolation valve electrical supply breakers and then verify that the SW isolation valves 22SW21 and 22SW22 were in the closed position. The operator was not provided nor did he take documentation into the field to control the lineup that he was directed to perform. At 8:49 a.m., while field operators completed restoration from the 22 SW header maintenance, SW flow was unexpectedly isolated to all EDGs and the EDGs were declared inoperable until 8:55 a.m., when SW flow was restored.

PSEG completed an evaluation for this event and determined that after removing the clearance tags from the 22 SW isolation valve breaker the field operator proceeded to check the position of 22SW21. However, PSEG determined that because the operator

did not have documentation that identified the valve positions that he was to verify with him in the field, he mistakenly went to the valve labeled 21SW21 on the in-service SW header instead of 22SW21. The 21 SW header was in service and supplying cooling water flow to the EDGs at that time therefore 21SW21 was open. Because the operator thought he was checking 22SW21, and expected that valve to be closed, he began to move the 21SW21 valve to the closed position. This caused an alarm in the control room and isolated all SW cooling to the EDGs making them all inoperable. Upon receipt of the alarm, control room operators immediately stopped fuel movement in progress and directed the operator to reopen 21SW21. This restored cooling water to the EDGs and returned them to an operable status. After independent verification of the valve's position was completed, operators declared the EDGs operable at 8:55 a.m.

PSEG determined during the evaluation that OP-AA-108-101-1002, "Component Configuration Control," requires that individuals performing component verification shall be provided a valve lineup sheet or written procedure that lists the valves to be manipulated or verified and the valve's required position. As stated above, for the 22 SW valve position verification performed on November 4, 2012, no valve line-up sheet or written procedure was used to control the status of the SW system. HU-AA-1211, "Pre-job Briefings," also requires that the worker immediately report any unexpected conditions to the job supervisor. When the valve was found in a position unexpected to the operator, based on information in the pre-job brief, he did not contact the job supervisor to receive additional guidance before manipulating the valve.

During its review of the significance of this event, PSEG determined that the 21SW21 could be remotely operated from the control room, and, therefore, the SW header was considered available during the inadvertent isolation on November 4 because simple operator action could have restored SW if necessary. On November 4, operators, being aware of plant conditions, and in particular, the fact that the EDGs were not operating, did not open the valve immediately upon receipt of the control room alarm due to concern with the safety of personnel. The valve was manually opened by an operator and, as a result, all three EDGs were inoperable for approximately five minutes.

PSEG entered this issue into their corrective action program under notification 20582240. To address the deficiencies noted with the pre-job brief and operator non-compliance with the configuration control standards, PSEG conducted human performance training with operations department supervisors and field operators. Licensed senior reactor operators also conducted human performance field observations once per shift during the remainder of the outage.

Analysis: The inspectors determined that not using a procedure or valve line-up sheet for the SW valve position verifications completed on November 4 was a performance deficiency that, based on the existence of PSEG procedure OP-AA-108-101-1002, was within the capability of PSEG to foresee and correct and should have been prevented. Specifically, PSEG personnel did not implement the requirements of component configuration control procedure, OP-AA-108-101-1002, and, as a result, isolated SW to the all of the EDGs. The performance deficiency was determined to be more than minor because it affected the configuration control attribute of the Mitigating Systems cornerstone to ensure the availability, reliability and capability of systems that respond to initiating events to prevent undesirable consequences. Specifically, a SW valve was incorrectly positioned isolating all cooling water to the EDGs. The inspectors evaluated the finding using IMC 0609.04, "Initial Characterization of Findings," and Attachment 1 of

IMC 0609, Appendix G, "Shutdown Operations Significance Determination Process Phase 1 Operational Checklists for Both PWRs and BWRs – Attachment 4 PWR Refueling Operation: RCS level >23' or PWR Shutdown Operation with Time to Boil >2 hours and Inventory in the Pressurizer." Because no loss of control occurred and all mitigating capabilities were available, a Phase 2 quantitative assessment was not required. Therefore, the inspectors determined the finding to be of very low safety significance (Green).

This finding had a cross-cutting aspect in the area of Human Performance, Work Practices, in that PSEG did not effectively utilize human error prevention techniques commensurate with the risk of the assigned task. Specifically, the pre-job brief did not enforce the expectation to contact supervision when an unexpected condition was identified, personnel did not perform self checking prior to component manipulation, and personnel proceeded in the face of uncertainty. [H.4(a)]

Enforcement: TS 6.8.1, "Procedures and Programs", requires that procedures be implemented as recommended in Appendix A of Regulatory Guide 1.33. Regulatory Guide 1.33, Section 1.c requires administrative procedures for equipment control to be implemented. Component Configuration Control procedure OP-AA-108-101-1002 requires use of a valve lineup sheet or written procedure when verifying a valve position. Contrary to the above, on November 4, 2013, PSEG did not use of a valve lineup sheet or written procedure when verifying a valve position in the service water system. Specifically, operators did not use documents required to be used in the field by the configuration control procedure, and inadvertently isolated the wrong EDG service water supply header, which made all of the Unit 2 EDGs inoperable. Because this deficiency was considered to be of very low safety significance (Green) and was entered into the corrective action program as notification 20582240, this violation is being treated as a NCV, consistent with Section 2.3.2 of the NRC Enforcement Policy. **(NCV 0500311/ 2013002-04, Inadvertent Isolation of Service Water to all EDGs in Mode 6)**

.2 (Closed) LER 05000311/2012-005-00: Reactor Trip Due to Failure of a Feedwater Control Valve

a. Inspection Scope

On November 25, 2012, Unit 2 tripped from 92 percent power due to the failure of a FCV to respond to the demanded position. The reactor operator attempted to manually control FCV 24BF19, but manual control did not result in the valve repositioning. Debris was identified in the positioner of the FCV, and prevented the FCV from responding to the required position. The inspectors completed a review of this LER and one finding was identified. This LER is closed.

b. Findings

Introduction: A self-revealing Green finding was identified because PSEG did not implement timely and effective corrective actions to address FCV positioner malfunctions that occurred between 2004 and 2012. The inspectors determined that minor malfunctions between 2007 and 2012 provided PSEG indication that the ability of FCVs to properly respond to plant transients remained adversely affected and that actions completed to date may not have been effective. As a result of PSEG's ineffective and

untimely action, on November 25, 2012, Unit 2 tripped from 92 percent power due to a malfunction of FCV 24BF19.

Description: FCV (BF19s) are non-safety related components installed in the feedwater lines for each steam generator. FCVs are placed in automatic or manual control, and adjust the level of water in the associated steam generator. Steam generator water level is determined based on the feed control system inputs, and FCVs reposition as demanded through the current to pneumatic (I/P) positioners. I/P positioners have small internal clearances and can fail to reposition the FCV when a blockage of the air pathway occurs. A signal is sent to the reactor protection system for a trip when a steam generator water level is too high or low.

On November 25, 2012, Unit 2 was ascending in power from a refueling outage when the unit tripped from 92 percent power due to a malfunction of FCV 24BF19. A control room alarm for the feedwater control system trouble was received and operators observed that 24BF19 actual position remained at 51 percent open while demand position was 71 percent open. Operators took manual control of the valve, but were unable to reposition the valve and the 24 steam generator water level continued to lower. Operators then entered S2.OP-AB.CN-001, "Main Feedwater/Condensate System Abnormality," and established manual reactor trip criteria of steam generator narrow range level <16 percent. Operators initiated actions to trip the plant when level reached 16%, but before the manual trip action could be completed, an automatic trip of the unit occurred at 14 percent steam generator water level. PSEG investigated the November 25, 2012, failure of 24BF19 and determined that debris, potentially from the manufacturing process, entered the FCV positioner, blocked the air pathway and caused the valve to remain at 51 percent open despite a higher demand by the system.

Unit 2 experienced a FCV positioner issue in 2004 that created corrective actions to replace the positioners. On July 13, 2004, and July 15, 2004, Unit 2 tripped from a 23BF19 FCV positioner failure and a root cause evaluation was performed. The 2004 root cause determined vendor quality issues existed with the shuttle inside of the positioners. The shuttles did not travel smoothly in the positioners, which caused the positioners to stick. PSEG addressed the vendor quality issues associated with the shuttles through the corrective action program, but also created a corrective action to prevent recurrence by replacing the FCV I/P positioners with digital controllers. Digital controllers were selected because they could handle large air volume changes, vibration and frequent cycling, which PSEG determined contributed to performance issues with the FCV I/P positioners at Salem. PSEG postponed installation of the digital controllers selected to replace the FCV positioners in 2008 due to concerns generated by industry experience with the model PSEG had selected.

Between 2007 and 2010, the station had experienced fourteen minor positioner malfunctions associated with positioners sticking. On May 7, 2010, a positioner issue with 13BF19 FCV was identified at Unit 1, resulting in Unit 1 down powering from 100 percent to 2 percent power on June 15, 2010, to replace a malfunctioning positioner. On June 17, 2010, Unit 1 down powered again and removed the main turbine from service to repair the 12BF19 FRV positioner. A root cause evaluation was performed and determined that the currently installed ABB AV2 series FCV positioners at both Salem units were susceptible to contaminants (debris). PSEG believed debris was entering the system through the air supply to the positioners. The root cause evaluation, dated August 16, 2010, determined that replacing the positioners with remote mounted digital

valve controllers would prevent recurrence of the FCV positioner failure, and this was designated as a corrective action to prevent recurrence. In February 2011, as part of the digital controller upgrade, PSEG developed an air filter system, and later that year decided to install the air filters first as an interim corrective action, and then at a later date install the digital controllers. Five minor positioner malfunctions associated with debris occurred between the filter installations in 2011 and the failure of 24BF19 on November 25, 2012. The inspectors determined that the five minor positioner malfunctions provided PSEG indication that the interim corrective actions taken were potentially not fully effective. The minor malfunctions were not recognized as a challenge to the effectiveness of the interim corrective actions, and the digital controller installation was rescheduled to a later outage. The controllers were scheduled for installation in October 2012, and then deferred to the next outage.

LS-AA-125, “Corrective Action Program,” in part, requires corrective actions designated to prevent recurrence be completed in a timely, effective, and complete manner, and that interim corrective actions are required when additional time is needed to implement final action to prevent recurrence. The procedure requires that the quality of interim actions must be such that they provide reasonable expectation of preventing recurrence until final action can be fully implemented. PSEG conducted a root cause evaluation (70146562) on the failure to replace the FCV pneumatic positioners with digital controllers in a timely manner. The root cause determined that the station did not properly apply appropriate decision making, problem identification and resolution and risk assessment processes when the station delayed the replacement of the FCV positioners. PSEG identified a project management risk assessment that was not implemented for the digital controller modification that may have provided additional insight on properly prioritizing the positioner replacement. In addition, the decision to delay the installation of the digital controller was not reviewed by the management review committee, which oversees the corrective action program, or the plant health committee, which provides a technical review for system improvements to the plant. Digital controller installation is scheduled for implementation in the next refueling outage at each unit. PSEG is currently developing additional training to target programmatic failures that led to gaps in established processes to ensure corrective actions are completed in a timely manner and that in cases where final corrective actions to prevent recurrence are delayed, effective interim corrective actions are identified and implemented.

Analysis: The inspectors determined that PSEG’s failure to address deficiencies with the pneumatic positioners for the FCVs in a timely manner in accordance with LS-AA-125, “Corrective Action Program,” was a performance deficiency. Specifically, PSEG did not implement effective corrective actions to prevent recurrence of FCV malfunctions that led to plant trips in both a 2010 and 2004. This led to the failure of the positioner and led to a plant trip on November 25, 2012. The inspectors determined, based on the results of PSEG’s cause evaluation and given the number of minor positioner malfunctions that occured between 2011, when in-line filters were installed as an interim measure, and November 2012 when the most recent trip occurred, that the basis for delaying the corrective action implementation was not reasonable. The performance deficiency was determined to be more than minor because it affected the equipment performance attribute of the Initiating Events cornerstone objective to limit the likelihood of events that upset plant stability and challenge critical safety functions during shutdown as well as at power operations. Specifically, the failure of the FCV to reposition as demanded resulted in a low steam generator water level and subsequent plant trip. In

accordance with IMC 0609.04, "Initial Screening and Characterization," and Exhibit 1 of IMC 0609, Appendix A, "The Significance Determination Process for Findings At-Power," issued June 19, 2012, the inspectors determined that this finding is of very low safety significance (Green) because the performance deficiency did not cause both a reactor trip and the loss of mitigation equipment relied upon to transition the plant from the onset of the trip to a stable shutdown condition.

This finding has a cross-cutting aspect in the area of Human Performance, Decision Making, because PSEG decisions did not demonstrate that nuclear safety is an overriding priority. Specifically, PSEG did not demonstrate conservative assumptions in decision making by postponing corrective actions to prevent recurrence over an eight year time span, despite numerous issues with the feedwater regulating valves that culminated in the plant tripping. [H.1(b)]

Enforcement: This finding does not involve enforcement action because no violation of a regulatory requirement was identified. Because this finding does not involve a violation and is of very low safety significance, it is identified as a finding. **(FIN 05000311/ 2013002-05, Failure to Implement Feedwater Control Valve Corrective Actions)**

.3 (Closed) LER 05000272/2012-005-00: Reactor Trip Due to Failure of the Main Power Transformer Overexcitation Relay

On December 21, 2012, Salem Unit 1 was operating at 100 percent power and automatically tripped due to a turbine trip. An overexcitation signal for the main generator tripped the main generator and caused the turbine to trip. The overexcitation relay does not input into the reactor protection system, and serves to preserve the main generator from damage. The overexcitation relay actuated below setpoint and has been removed from the system. Two other means of overexcitation protection remain in place for the Unit 1 main generator. Testing and calibration were performed on the overexcitation relay prior to its installation March 27, 2009. The inspectors completed a review of this LER and did not identify a violation of regulatory requirements. This LER is closed.

b. Findings

No findings were identified.

4OA6 Meetings, Including Exit

On April 4, 2013, the inspectors presented the inspection results to Mr. Fricker, Vice President of Salem Operations, and other members of the PSEG staff. 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
J. Garecht, Work Managment Director
R. Denight Jr., Operations Director
K. Chambliss, Regulatory Affairs Manager
T. Cachaza, Regulatory Assurance
K. King, Regulatory Assurance
D. LaFleur, Regulatory Assurance
C. Dahms, Regulatory Assurance
M. Rahmani, Engineer, Batteries
J. Ridgeway, Engineer, Cathodic Protection
R. Wegner, Maintenance Director
G. Sosson, Engineering Director
S. Taylor, Radiation Protection Manager
J. Stavely, Nuclear Oversight Manager
M. Pyle, Chemistry Manager
J. Pantazes, Manager, Nuclear Environmental Affairs
J. Gibley, Salem Fire Marshal
A. Lawrence, Seasonal Readiness Coordinator
T. Frye, Distribution Relay Supervisor
C. Banner, Emergency Preparedness Manager
S. Thomassen, Emergency Preparedness Station Manager

LIST OF ITEMS OPENED, CLOSED, DISCUSSED, AND UPDATED

Opened/Closed

05000272/2013002-01	NCV	Failure to Correct Condition Adverse to Quality in Service Water Check Valve (Section 1R12)
05000272/2013002-02	NCV	Failure to Install the Correct Size Zinc Anode in 11 Service Water Strainer Results in Strainer Trip (Section 1R12)
05000272, 311/2013002-03	FIN	Inadequate Relay Testing Instructions Cause Loss of One Offsite Power Source (Section 1R12)
05000311/2013002-04	NCV	Inadvertent Isolation of Service Water to all EDGs in Mode 6 (Section 4OA3)

05000311/2013002-05	FIN	Failure to Implement Feedwater Control Valve Corrective Actions (Section 4OA3)

Closed

05000311/2012-004-0	LER	Isolation of Service Water to the Emergency Diesel Generators While in Mode 6 (Section 4OA3)
05000311/2012-005-0	LER	Reactor Trip Due to Failure of a Feedwater Control Valve (Section 4OA3)
05000272/2012-005-0	LER	Reactor Trip Due to Failure of the Main Power Transformer Overexcitation Relay (Section 4OA3)

LIST OF DOCUMENTS REVIEWED

Section 1R01: Adverse Weather Protection

Procedures
WC-AA-107, Seasonal Readiness, Revision 12
SC.OP-AB.ZZ-0003, Component Fouling, Revision 14
SC.MD-PM.SW-0003, Service Water Auto Strainer Adjustment, Inspection, Repair, and Replacement, Revision 38
SC.OP-PT.ZZ-0002, Station Preparations for Seasonal Conditions, Revision 11
SVP-2012-025, 2013 Salem Grassing Seasonal Readiness Affirmation, dated 12/28/12

Notifications
20600459 20600526

Maintenance Orders/Work Orders

70146343	70135747	60098773	60104507	60102501	30220322
30222921	30225749	30129048	30215212	80105928	

Section 1R04: Equipment Alignment

Procedures
S1.OP-SO.CC-0001, Component Cooling System Operation, Revision 17
S1.OP-ST.CS-0001, In-service Testing – 11 Containment Spray Pump, Revision 18
S1.OP-ST.DG-0004, 11 Fuel Oil Transfer System Operability Test, Revision 24
S1.OP-ST.DG-0008, 1C Diesel Generator Auxiliaries Air Start Valve Test, Revision 9
S1.OP-ST.CVC-0003, In-service Testing – 11 Charging Pump, Revision 23

Notifications (*denotes NRC-identified)
20564020 20589740 20589673*

Drawings
205231, No. 1 Unit Component Cooling – Sheet 1, Revision 66
205235, No. 1 Unit Containment Spray, Revision 48
205241, No. 1 & 2 Units Diesel Engine Auxiliaries, Revision 43
205242, No. 1 Unit Service Water Nuclear Area, Revision 93
205228, No. 1 Unit Chemical and Volume Control Operation, Revision 81

Other Documents
WCM Lineup Template #1077, Diesel Auxiliaries
WCM Lineup Template #775, 1C Diesel Electrical Systems

Section 1R05: Fire Protection

Procedures
CC-AA-211, Fire Protection Program, Revision 4
FRS-II-433, Salem Unit 1 (Unit 2) Pre-Fire Plan, Auxiliary Feed Water Pumps Area, Elevation 84', Revision 6
FRS-II-721, Salem Unit 1 (Unit 2) Pre-Fire Plan, Fuel Handling Building, Elevation 130', Revision 2
FRS-II-911, Salem Unit 1 (Unit 2) Pre-Fire Plan, Service Water Intake Structure, Elevations 92' & 112', Revision 2

Notifications (*denotes NRC-identified)
20586579* 20586580* 20594235* 20594397*

Section 1R06: Flood Protection Measures

Procedures
ND.DE-PS.ZZ-0010(Q)-A5, Internal Hazards Program / Flooding Analysis, Revision 1
SC.FP-SV.FBR-0026(Q), Flood & Fire Barrier Penetration Seal Inspection, Revision 5
SI.OP-AB.SW-0001, Loss of Service Water Header Pressure, Revision 17
SI.OP-AB.SW-0002, Flooding, Revision 3

Notifications
20538021 20580010

Drawings
602107, Unit 1&2 Penetration Seal Locations, 100' elevation, Sheet 1, Revision 1

Other Documents
Design Calculation S-1-A900-MDC-0017

Section 1R11: Licensed Operator Requalification Program

Procedures
1-EOP-LOCA-1, Loss of Reactor Coolant, Revision 25
1-EOP-TRIP-1, Reactor Trip or Safety Injection, Revision 27
HU-AA-1211, Pre-job Briefings, Revision 10

Maintenance Orders/Work Orders
60108664

Other Documents
MA-AA-716-004, Unit 2 Neutral Bushing Troubleshooting Plan, dated 2/20/13

Section 1R12: Maintenance Effectiveness

Procedures
SM-AA-300-1001, Procurement Activities and Responsibilities, Revision 9
SC.MD-PM.SW-0003, Service Water Auto Strainer Adjustment, Inspection, Repair and Replacement, Revision 32
ER-AA-310, Implementation of the Maintenance Rule, Revision 11
ER-SA-310-1009, Salem Generating Station – Maintenance Rule Scoping, Revision 3
DE-CB.SW-0047, Configuration Baseline Documentation for Service Water System, Revision 7
SC.MD-PM.ZZ-0123, Disassembly, Inspection and Reassembly of Dual Plate Check Valves, Revision 14
MA-AA-1000, Conduct of Maintenance Manual, Revision 14
MA-AA-716-010-1009, Written Work Instruction for Planners, Revision 0
MA-AA-716-011, Work Execution and Closeout, Revision 13
MA-AA-723-307, Relay Testing, Revision 2
WC-AA-10, Work Management Process Description, Revision 2
WC-AA-101, Online Work Management Process, Revision 19
WC-AA-8000, Salem and Hope Creek 500 KV Switchyard Construction and Maintenance Activities Interface Procedure, Revision 2

Notifications

20384681	20543480	20545994	20548227	20569597	20570434
20581163	20585570	20585571	20585572	20585573	20585574
20585575	20588373	20588375	20588376	20588377	20588378
20588379	20460028	20504289	20473451	20466861	20377849
20435570	20439313	20448279	20585353	20592184	20580655
20580653	20580117	20592069	20592250	20592351	20592354
20594628					

Maintenance Orders/Work Orders

30198882	60106377	70090278	70120961	70146343	70111537
70145771	50151794	50104557	30189190		

Other Documents
EPRI Plant Support Engineering: Guidelines for the Technical Evaluation of Replacement Items in Nuclear Power Plants, Revision 1
Material Master x369698, Anode-Zinc, MTLO Cooler, Switch Side
Material Master x377189, Anode-(Zinc) Belmont Metals Style B
Salem 1, 11 SW Pump Unavailability (Cumulative) Chart, 12/2009 - 12/2012
Salem 1, 11 SW Pump Unavailability a(1) Goal Unavailability (Cumulative) Chart, 12/2009 - 12/2012
Salem 1, SW System Health Report, Q4-2012
Salem 2, CN System Health Report, Q1-2013
Salem Maintenance Rule Functional Failures 2012, dated 2/27/13

S-C-SW-MEE-1910, Salem Units 1&2 CFCU Accumulator Injection Piping-Allowable Levels of Silt Accumulation during Plant Operations, Revision 1
Salem 1, Narrative Log, January 12, 2013
Salem 2, Narrative Log, January 12, 2013
Drawing, #219386, Revision 10

Section 1R13: Maintenance Risk Assessments and Emergent Work Control

Procedures
S1.OP-SO.PC-0001, Switchgear and Penetration Areas Ventilation Operation, Revision 19

Notifications (*denotes NRC-identified)
20592451* 20593608 20596303

Maintenance Orders/Work Orders
70146983

Drawings
205239, Unit 1 Waste Disposal Liquid – Sheet 3, Revision 46
205201, Unit 1 Reactor Coolant – Sheet 1, Revision 63
205248, Unit 1 Control Area Air Conditioning & Ventilation, Revision 36

Other Documents
Salem Generating Station, Unit 2 Risk Assessment, dated 1/5/13
Salem Generating Station, Unit 2 Narrative Logs, dated 1/11/13
Salem Generating Station, Unit 1 Narrative Logs, dated 2/4/13
Salem Generating Station, Unit 1 Risk Assessment, dated 1/5/2013
Salem Generating Station, Unit 1 Risk Assessment, dated 2/4/2013
Salem Generating Station, Unit 2 Risk Assessment, dated 12/12/2012
Salem Generating Station, Unit 1 Control Room Logs, dated 2/4/13
Salem Unit 1, Adverse Condition Monitoring Plan – 1PR1/1PR2 Leakage Monitoring, dated 1/15/13
OTDM 12-006, 1PR1 & 1PR2 Pressurizer Power Operated Relief Valves, Revision 3

Section 1R15: Operability Determinations and Functionality Assessments

Procedures
MA-AA-716-230-1002, Vibration Analysis/Acceptance Guideline, Revision 3

Notifications (*denotes NRC-identified)
20594275* 20597765 20597943 20598565*

Maintenance Orders/Work Orders
60105092 60104113 60104114 50100171 70149731

Drawings
229988, Redundant Air Supply Assembly in Control Panels, Revision 7
205343, No.2 Unit – Auxiliary Building Control Air, Revision 41
205336, No. 2 Unit Auxiliary Feedwater, Revision 50

Other Documents
Advanced Nuclear Technology: Startup Program Guideline, 2011 Technical Report
23 Chiller, 2CHE19-M1A and M2A, vibration trends, dated January 29, 2013

Section 1R19: Post-Maintenance Testing

Procedures
MA-AA-716-012, Post Maintenance Testing, Revision 18
SC.MD-CM.125-0005, 125VDC Vital Bus Battery Cell Replacement, Revision 8
SC.MD-CM.SEC-0001, Safeguard Equipment Control Troubleshooting, Revision 12
S2. MD-FT.SEC-0003, 2C Safeguard Equipment Control Sequencer Surveillance Test Procedure, Revision 24
SC.IC-CC.RM-0076, R45 Plant Vent Noble Gas High Range Process Radiation Monitor, Revision 29
S2.OP-ST.RM-0001, Radiation Monitors – Check Sources, Revision 28
SH.IC-TI.ZZ-0001, Electronic Soldering/Desoldering, Revision 5
SC.IC-ST.NIS-0003, N43 Power Range, Revision 17

Notifications (*denotes NRC-identified)
20589172 20589393 20592354 20599170*

Maintenance Orders/Work Orders
60062787 60071063 60109000 50142355

Other Documents
SCT-1200 Capacity Test Report, 2A 125VDC battery cell 36, dated 1/11/13

Section 1R22: Surveillance Testing

Procedures
S1.OP-ST.DG-0001, 1A Diesel Generator Surveillance Test, Revision 44
S2.OP-ST.CVC-0003, Inservice Testing – 21 charging pump, Revision 25
S1.OP-ST.RC-0008, RCS Inventory Balance, Revision 24
SC.RE-ST.ZZ-0007(Q), Moderator Temperature Coefficient Measurement, Revision 15
S2.OP-ST.SW-0001(Q), Inservice Testing – 21 Service Water Pump, Revision 32
S2.IC-SC.RCP-0034, 2LT-518 #21 Steam Generator Level Protection Channel III, Revision 11
S2.IC-SC.RCP-0054, 2LT-538 #23 Steam Generator Level Protection Channel III, Revision 10

Notifications (*denotes NRC-identified)
20585176 20589916* 20600516

Maintenance Orders/Work Orders
50153141 50154715 50146149 50146298

Section 1EP2: Alert and Notification System Evaluation

Procedures
EP-AA-121-1002, PSEG Alert Notification System (ANS) Program, Revision 0
EP-AA-121-1004, PSEG ANS Corrective Maintenance, Revision 1
EP-AA-121-1005, PSEG ANS Preventive Maintenance, Revision 2

EP-AA-121-1006, PSEG ANS Siren Monitoring, Troubleshooting, and Testing, Revision 1

Other Documents
ANS maintenance records, January 2012 – December 2012
ANS test records, April 2011 – February 2013
Final REP-10 Design Review Report, PSEG Salem and Hope Creek Generating Stations, dated 1/6/2006
Letter from FEMA Region II to NJ OEM, REP Unit, Status of Provisions for Back-up Alert and Notification for the Salem Hope Creek Nuclear Power Station Emergency Planning Zone, dated 12/6/2012
Letter from FEMA Region III to Delaware Emergency Management Agency, Status of Provisions for Back-up Alert and Notification for the Salem Hope Creek Nuclear Power Station Emergency Planning Zone, dated 11/28/2012
Letter from PSEG Nuclear LLC to NJ RERP &Technical Unit Emergency Response, Incorporation of Back-up Means of ANS Into Siren Design Report, dated 10/5/2012

Section 1EP3: Emergency Response Organization Staffing and Augmentation System

Procedures
EP-AA-120-1007, Maintenance of Emergency Response Organization, Revision 4
EP-AA-120-1010, Emergency Preparedness Training Administration, Revision 0
EP-AA-121-1001, Automated Call-Out System Maintenance, Revision 0
HC.EP-EP.ZZ-0204, Emergency Response Callout/Personnel Recall, Revision 2
SC.EP-EP.Z-0204, Emergency Response Callout/Personnel Recall, Revision 2

Other Documents
ERO roster dated 3/21/2013
Hope Creek Generating Station and Salem Generating Station, On-Shift Staffing Analysis Report, Revision 0
Monthly pager test results March 2011-February 2013
Practice Exercise Critique Report (H12-01), dated 4/24/2012
Unannounced drill critique report (H11-U1), dated 9/26/2011
Unannounced drill critique report (S12-U1) dated 10/2/2012

Section 1EP4: Emergency Action Level and Emergency Plan Changes

Other Documents
EP-SA-111-F1, Salem ECG Attachment 1, Unusual Event, Revision 1
EP-SA-111-F2, Salem ECG Attachment 2, Alert, Revision 1
EP-SA-111-F3, Salem ECG Attachment 3, Site Area Emergency, Revision 2
EP-SA-111-F4, Salem ECG Attachment 4, General Emergency, Revision 1
Emergency Plan Section 1, Introduction, Revision 16
Emergency Plan Section 3, Emergency Organization, Revision 28

Section 1EP5: Correction of Emergency Preparedness Weaknesses

Procedures
EP-AA-120-1001, 10 CFR 50.54(q) Change Evaluation, Revision 2
EP-AA-125, Emergency Preparedness Self Evaluation Process, Revision 0
LS-AA-104, 50.59 Review Process, Revision 6

WC-AA-106, Work Week Screening and Processing, Revision 12

<u>Other Documents</u>
Audit NOSA-HPC-12-02, Emergency Preparedness Audit Report, dated 4/12/2012
Audit NOSA-HPC-13-02, Emergency Plan, Procedures, Facilities, and Interfaces Audit Report, dated 3/28/2013
Check-In Self-Assessment (70145124) for 2013 NRC EP Program Inspection
Event Report Common Unusual Event August 23, 2011
Event Report Salem Unusual Event April 30, 2012
Event Report Salem Unusual Event July 14, 2011
Memoranda of Understanding between Department of Commerce – National Weather Service and PSEG Nuclear, LLC, dated 2/23/2012
Memoranda of Understanding Cumberland County Office of Emergency Management and PSEG Nuclear, LLC, dated 6/28/2012
Memoranda of Understanding Delaware Department of Safety and Homeland Security, Delaware Emergency Management Agency and PSEG Nuclear, LLC, dated 3/2/2012
Memoranda of Understanding Kent County Department of Public Safety Kent County EOC and PSEG Nuclear, LLC, dated 4/6/2012
Memoranda of Understanding Maryland Emergency Management and Civil Defense Agency/NJ State Police, dated 9/19/2012
Memoranda of Understanding Memorial Hospital of Salem County and PSEG Nuclear, LLC, dated 2/27/2012
Memoranda of Understanding New Castle County Delaware, Delaware Emergency Management Agency and PSEG Nuclear, LLC, dated 7/9/2012
Memoranda of Understanding NJ State Police/NJ Department of Environmental Protection/PSEG, dated 10/2/2012
Memoranda of Understanding Pennsylvania Emergency Management Agency/NJ State Police, dated 2/6/2012
Memoranda of Understanding Salem County Department of Emergency Services and PSEG Nuclear, LLC, dated 6/19/2012
Memoranda of Understanding Township of Lower Alloways Creek and PSEG Nuclear, LLC, dated 3/23/2012
NOH-12-028, Nuclear Oversight 3C12 Mid-Cycle Assessment Report, dated 2/13/2013
NOSPA-HC-11-1C, Nuclear Oversight Assessment Report, January through April 2011
NOSPA-HC-11-2C, Nuclear Oversight Assessment Report, May through August 2011
NOSPA-HC-11-3C, Nuclear Oversight Assessment Report, September through December 2011
NOSPA-HC-12-1C, Nuclear Oversight Assessment Report, January through April 2012
NOSPA-HC-12-2C, Nuclear Oversight Assessment Report, May through August 2012
NOSPA-HC-12-3C, Nuclear Oversight Assessment Report, September through December 2012
PSEG Nuclear LLC Emergency Plan, Revision 71
Salem-Hope Creek Nuclear Generating Station Development of Evacuation Time Estimates, Revision 0
S12-01, Emergency Preparedness Onsite Drill Critique Report, dated 2/9/2012
S12-02, Emergency Preparedness Onsite Drill Critique Report, dated 6/13/2012
S12-03, Emergency Preparedness Onsite Drill Critique Report, dated 12/6/2012
H12-01, Emergency Preparedness Onsite Drill Critique Report, dated 4/3/2012
H12-02, Emergency Preparedness Onsite Drill Critique Report, dated 5/22/2012
H12-03, Emergency Preparedness Onsite Drill Critique Report, dated 9/13/2012
H13-01, Emergency Preparedness Onsite Drill Critique Report, dated 2/5/2013

Notifications

20518624	20551678	20577851	20588407
20525597	20553567	20578469	20588423
20527223	20554333	20580256	20591163
20542063	20556990	20580271	20593374
20543771	20562713	20581143	
20545017	20573906	20586753	

Section 1EP6: Drill Evaluation

Procedures
EP-SA-111-121, Fission Product Barrier Table, Revision 0
EP-SA-111-115, ATWT Criticality, Revision 0

Notifications (*denotes NRC-identified)

20599924	20599925	20600009	20600206	20600240	20600555*

Other Documents
Salem Training Drill – S13-01, dated 3/19/13

Section 4OA1: Performance Indicator Verification

Procedures
S1.OP-ST.RC-0008, RCS Inventory Balance, Revision 24
S2.OP-ST.RC-0008, RCS Inventory Balance, Revision 34
EP-AA-125-1001, EP Performance Indicator Guidance, Revision 0
EP-AA-125-1002, ERO Performance – Performance Indictor Guidance, Revision 0
EP-AA-125-1003, ERO Readiness – Performance Indicator Guidance, Revision 0

Other Documents
LER 05000272/2012-001-00, Single Train Actuation of Safety Injection Due to Failure of Solid State Protection System
LER 05000272/2012-002-00, Service Water Loop Inoperable for Time Greater Than Allowed by Technical Specifications
LER 05000311/2012-001-00, Automatic Reactor Trip due to Turbine Trip
LER 05000311/2012-002-00, Auxiliary Feedwater Flow Control Valve Failed Open with Zero Demand
LER 05000311/2012-004-00, Isolation of Service Water to the Emergency Diesel Generators While in Mode 6
LER 05000311/2012-005-00, Reactor Trip Due to Failure of a Feedwater Control Valve

Section 4OA2: Problem Identification and Resolution

Procedures
SC.MD-ST.ZZ-0003, Inspection and Preventive Maintenance of Unit 1, 2 & 3 Batteries, Revision 32
SC.MD-ST.125-0003, Quarterly Inspection and Preventive Maintenance of Units 1, 2 and 3 125 Volt Station Batteries
SCT-1200 Capacity Test Report, 2A 125VDC battery cell 36, dated 1/11/13

Notifications (*denotes NRC-identified)

20517770	20504976	20503520	20591437	20518713	20566456
20547574	20593639	20589599	20589393	20528010	20506061
20541279	20581242	20512046	20507907	20508285	20510859
20507551	20508283	20542162	20559378	20592330	20580539
20542631	20523516	20584747	20593413	20583420	20554874
20589172	20507922	20505139	20495313	20496077	20567703
20595276	20600557*				

Maintenance Orders/Work Orders

70126635	70147699	70124286	70119080	70133336	60075983
50147215					

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

Procedures
MA-AA-716, Conduct of Troubleshooting, Revision 11
SH.MD-PM.ZZ-0029, Relay Testing, Revision 8
LS-AA-125-1001, Root Cause Evaluation Manual, Revision 8
LS-AA-125, Corrective Action Program, Revision 16
OP-AA-108-101-1002, Component Configuration Control, Revision 5

Notifications

20588627	20589491	20585172	20466937	20582240	20462115
20433910	20462084	20460028			

Maintenance Orders/Work Orders

60080307	70147697	70146562	70111537	70040334	70146562
60094548	80099809	30151995			

Other Documents
LS-AA-104-1001, 50.59 Review Coversheet Form –NUCP 80108099, Revision 2
OP-SA-108-114-1001, Post-Trip Data Collection Guidelines – Salem, Revision 3, dated 12/21/12
LER 05000272/84-014, Unit 1 Vital Bus Blackout Actuation
VTD 315135, Limitorque Engineering Reference Manual

LIST OF ACRONYMS

ADAMS	Agencywide Documents Access and Management System
ANS	Alert and Notification System
CC	component cooling
CFCU	containment fan cooler unit
CFR	Code of Federal Regulations
CS	containment spray
EDG	emergency diesel generator
EP	emergency preparedness
ERF	emergency response facility
ERO	Emergency Response Organization
FCV	feedwater control valve
IMC	Inspection Manual Chapter
LER	licensee event report
NCV	non-cited violation
NEI	Nuclear Energy Institute
NRC	Nuclear Regulatory Commission
OOS	out of service
PC	procurement code
PORV	power operated relief valve
PSEG	Public Service Enterprise Group Nuclear LLC
RCS	reactor coolant system
SDP	Significance Determination Process
SPAV	switchgear penetration area ventilation
SPT	station power transformer
SSC	structure, system, or component
SW	service water
TS	technical specifications
UFSAR	Updated Final Safety Analysis Report
Vdc	volts direct current