UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION I
2100 RENAISSANCE BLVD., SUITE 100
KING OF PRUSSIA, PA 19406-2713

July 28, 2015

Mr. Robert C. Braun
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 – INTEGRATED INSPECTION REPORT 05000272/2015002 AND 05000311/2015002

Dear Mr. Braun:

On June 30, 2015, 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 July 9, 2015, with Mr. John Perry, Salem Site Vice President, 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 three NRC-identified findings and three self-revealing findings of very low safety significance (Green). All 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, consistent with Section 2.3.2.a of the NRC Enforcement Policy. If you contest the non-cited violations 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, or a finding not associated with a regulatory requirement 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 Title 10 of the *Code of Federal Regulations* (10 CFR) 2.390 of the NRC's "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 and 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 and 50-311
License Nos. DPR-70 and DPR-75

Enclosure:
Inspection Report 05000272/2015002 and 05000311/2015002
w/Attachment: Supplementary Information

cc w/encl: Distribution via ListServ

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U.S. NUCLEAR REGULATORY COMMISSION

REGION I

Docket Nos.	50-272 and 50-311
License Nos.	DPR-70 and DPR-75
Report Nos.	05000272/2015002 and 05000311/2015002
Licensee:	PSEG Nuclear LLC (PSEG)
Facility:	Salem Nuclear Generating Station, Units 1 and 2
Location:	P.O. Box 236 Hancocks Bridge, NJ 08038
Dates:	April 1, 2015 through June 30, 2015
Inspectors:	P. Finney, Senior Resident Inspector A. Ziedonis, Resident Inspector S. Haney, Acting Senior Resident Inspector R. Barkley, PE, Senior Project Engineer S. Galbreath, Reactor Inspector S. McCarver, Senior Project Engineer T. Hedigan, Operations Engineer R. Nimitz, Senior Health Physicist
Approved By:	Glenn T. Dentel, Chief Reactor Projects Branch 3 Division of Reactor Projects

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SUMMARY

Inspection Report (IR) 05000272/2015002, 05000311/2015002; 04/01/2015 – 06/30/2015; Salem Nuclear Generating Station Units 1 and 2; Maintenance Effectiveness, Operability Determinations and Functionality Assessments, Drill Evaluation, Problem Identification and Resolution.

This report covered a three-month period of inspection by resident inspectors and announced inspections performed by regional inspectors. The inspectors identified three NRC-identified findings and three self-revealing findings of very low safety significance (Green), all of which were non-cited violations (NCVs). 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 April 29, 2015. Cross-cutting aspects are determined using IMC 0310, “Aspects Within Cross-Cutting Areas,” dated December 4, 2014. All violations of NRC requirements are dispositioned in accordance with the NRC’s Enforcement Policy, dated February 4, 2015. The NRC’s program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG-1649, “Reactor Oversight Process,” Revision 5, dated February 2014.

Cornerstone: Mitigating Systems

- Green. A self-revealing Green NCV of Title 10 of the *Code of Federal Regulations* (10 CFR), Part 50, Appendix B, Criterion XVI, “Corrective Action,” was identified for PSEG’s failure to take timely corrective action to correct a condition adverse to quality (CAQ). Specifically, PSEG failed to replace the 12 chiller motor as a corrective action to address extent of condition following a 13 chiller motor failure in 2008. The 12 chiller motor subsequently failed on March 27, 2015. PSEG replaced the 12 chiller motor and the stationary and movable contacts in the main contactor panel.

  This issue was more than minor because it was associated with the equipment performance attribute of the Mitigating System cornerstone, and adversely affected its objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. Specifically, the untimely corrective action resulted in emergent unavailability and associated inoperability of the 12 chiller. The inspectors determined that the finding was of very low safety significance (Green) in accordance with Exhibit 2 of IMC 0609, Appendix A, The Significance Determination Process for Findings At-Power, dated June 19, 2012, because the finding was not a design or qualification deficiency, did not represent a loss of safety system function, did not represent the loss of function for any technical specification (TS) system, train, or component beyond the allowed TS outage time, and it did not represent an actual loss of function of any non TS trains of equipment designated as high safety significance in accordance with PSEG’s maintenance rule program. The inspectors determined that this finding had a cross-cutting aspect in the area of Problem Identification and Resolution, Resolution, because PSEG did not take effective corrective actions to address issues in a timely manner commensurate with their safety significance. Specifically, PSEG did not replace the motor over a six year period despite having numerous opportunities to replace the 12 chiller motor prior to its failure. [P.3] (Section 1R15)

- Green. A self-revealing Green NCV of 10 CFR 50, Appendix B, Criterion V, “Instruction, Procedures, and Drawings,” was identified because PSEG did not establish an appropriate interval to overhaul 4kV General Electric (GE) Magne-Blast breakers. As a result, the safety-related breakers for the 12 safety injection (SI) pump and 11 component cooling water (CCW) pump were operated beyond the industry recommended overhaul interval and subsequently failed. PSEG’s corrective actions included replacing the 12 SI pump and 11 CCW pump breakers, and reducing the overhaul preventive maintenance (PM) frequency to 12 years.

  This finding is more than minor because it is associated with the equipment performance attribute of the Mitigating Systems cornerstone, and adversely affected the cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. Specifically, PSEG did not consider industry recommendations nor develop a basis when establishing 4kV GE Magne-Blast breaker overhaul intervals, which resulted in failure of the 12 SI pump and 11 CCW pump breakers. In accordance with Exhibit 2 of IMC 0609, Appendix A, “The Significance Determination Process for Findings At-Power,” issued June 19, 2012, the inspectors determined that the finding was of very low safety significance (Green), because the finding was not a deficiency affecting the design or qualification of the mitigating system; it did not represent a loss of system function; it did not represent the loss of function for any TS system, train, or component beyond the allowed TS outage time; and it did not represent an actual loss of function of any non TS trains of equipment designated as high safety significance in accordance with PSEG’s maintenance rule program. The inspectors determined this finding has a cross-cutting aspect in the area of Problem Identification and Resolution, Operating Experience, because PSEG did not systematically and effectively collect, evaluate, and implement relevant internal and external operating experience in a timely manner. Specifically, the overhaul frequencies assigned to safety-related 4KV breaker inspections were inadequate to ensure the breakers would operate properly. [P.5] (Section 4OA2.3)

- Green. The inspectors identified a Green NCV of TS 6.8.1, “Procedures and Programs,” as described in Regulatory Guide (RG) 1.33, Revision 2, February 1978, when PSEG performed chiller water system maintenance activities that were not properly preplanned in accordance with documented instructions, resulting in multiple chiller system trips on both units. Specifically, PSEG maintenance procedure SC.MD-PM.CH-0001, “ACME Chiller Compressor Inspection and Repair,” did not incorporate documented instructions from the vendor technical document. PSEG performed an apparent cause evaluation (ACE) 70171934, and revised the maintenance procedure that included detailed vendor instructions.

  This finding was more than minor because it was associated with the equipment performance attribute of the Mitigating System cornerstone, and adversely affected the cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. Specifically, failure to install the chiller evaporator gasket in accordance with written instructions from the vendor manual resulted in multiple chiller failures. Using IMC 0609, Attachment 4, “Initial Characterization of Findings,” and Exhibit 2 of IMC 0609, Appendix A, “The Significance

Determination Process for Findings At-Power," dated June 19, 2012, the inspectors determined that this finding was of very low safety significance (Green) because the finding was not a design or qualification deficiency, did not represent a loss of safety system function, did not represent the loss of function for any TS system, train, or component beyond the allowed TS outage time, and it did not represent an actual loss of function of any non TS trains of equipment designated as high safety significance in accordance with PSEG's maintenance rule program. This finding had a cross-cutting aspect in the area of Problem Identification and Resolution, Evaluation, in that licensees thoroughly evaluate issues to ensure that resolutions address causes and extent of conditions commensurate with their significance. Specifically, PSEG did not thoroughly evaluate chiller divider plate head gasket failures in 2012, such that the resolution addressed the inadequate maintenance procedure instructions. [P.2] (Section 4OA2.5)

Cornerstone: Barrier Integrity

- Green. A self-revealing Green NCV of 10 CFR 50, Appendix B, Criterion XVI, "Corrective Action," was identified when PSEG did not implement corrective actions in a timely manner. Specifically, PSEG identified a degrading trend in the stroke time for the 25 containment fan cooling unit (CFCU) service water (SW) outlet valve, 25SW72, but failed to implement corrective actions to address the trend prior to its failure to stroke in the required time. PSEG troubleshooting identified that air pressure on its air regulator had been set too low for the air volume required to stroke the valve. PSEG adjusted the regulator air and entered this issue in their corrective action program (CAP) as notifications 20661667, 20661710, and 20662206.

  The issue was determined to be more than minor since it was associated with the system, structure, or component and barrier performance attribute of the Barrier Integrity cornerstone, and adversely affected its objective to provide reasonable assurance that physical design barriers protect the public from radionuclide releases caused by accidents or events. Specifically, the lack of timely corrective actions ultimately resulted in exceeding the valve's capability to reposition in the in-service test (IST) and Updated Final Safety Analysis Report (UFSAR) required stroke time for containment isolation. The finding was evaluated in accordance with Exhibit 3 of IMC 0609, Appendix A, "The Significance Determination Process for Findings At-Power," issued June 19, 2012, where it screened to very low safety significance (Green) since it was did not represent an actual open pathway in the physical integrity of reactor containment, containment isolation system, and heat removal components, nor did it involve the hydrogen igniter function. The inspectors determined this finding has a cross-cutting aspect in Human Performance, Teamwork, in that individuals and work groups communicate and coordinate their activities within and across organizational boundaries to ensure nuclear safety is maintained. Specifically, PSEG staff did not collaborate during operational activities such as CAP implementation, work management, and trend analyses to ensure the degrading stroke time was addressed. [H.4] (Section 1R12)

Cornerstone: Occupational Radiation Safety

- Green. The inspectors identified a Green NCV of TS 6.12, 'High Radiation Area," when PSEG did not apply appropriate controls to high radiation areas. Specifically, the Unit 1 and 2 reactor cavities in containment, which are areas that exceed 1.0 rem/hour at 30 centimeters, were not properly controlled to prevent unauthorized personnel access. PSEG entered this issue in their CAP as notification 20682903 and installed six foot high scissor fences around each reactor cavity.

  The issue was determined to be more than minor since it was associated with the program and process attribute of the Occupational Radiation Safety cornerstone, and adversely affected its objective to ensure the adequate protection of the worker health and safety from exposure to radiation from radioactive material during routine civilian nuclear reactor operation. Specifically, high radiation areas with dose rates greater than 1.0 rem/hour at 30 centimeters were not properly controlled to prevent unauthorized personnel access. It was also similar to IMC 0612, Appendix E, example 6.g, in that access to a posted high radiation area (HRA) was not controlled in accordance with site TSs, a HRA actually existed, and it was not properly barricaded. The finding was then evaluated using IMC 0609, Appendix C, "Occupational Radiation Safety Significance Determination Process," issued August 19, 2008, where it screened to very low safety significance (Green) since it was not associated with an as low as is reasonably achievable (ALARA) issue, did not involve an overexposure, did not constitute a substantial potential for overexposure, and did not compromise PSEG's ability to assess dose. The inspectors determined this finding has a cross-cutting aspect in the area of Human Performance, Avoid Complacency, in that individuals recognize and plan for the possibility of latent problems, even while expecting successful outcomes. Specifically, PSEG was not sufficiently aware of latent deficiencies in HRA access control given opportunities to identify the inadequate HRA controls when performing containment entries during normal plant operation and when routinely establishing the reactor cavities as locked high radiation areas following refueling outages. [H.12] (Section 4OA2.1)

Cornerstone: Emergency Preparedness

- Green. The inspectors identified a Green NCV of 10 CFR 50.54(q)(2) when PSEG did not maintain an adequate emergency classification and action level scheme that met the planning standards of 10 CFR 50.47(b). Specifically, PSEG did not establish an effective emergency plan with respect to declaring an Alert for seismic activity in excess of an operating basis earthquake (OBE), specifically vertical acceleration. PSEG entered this issue into their CAP as notification 20691160 and developed a temporary Operations standing order.

  The issue was determined to be more than minor since it was associated with the procedure quality attribute of the Emergency Preparedness cornerstone, and adversely affected its objective to ensure that licensees are capable of implementing adequate measures to protect the health and safety of the public in the event of radiological emergency. Specifically, PSEG would not declare on Alert based on exceeding their OBE without actuation of the Hope Creek seismic switch. The issue was reviewed in accordance with IMC 0609, Appendix B, "Emergency Preparedness Significance Determination Process," issued September 26, 2014, where it screened to very low safety significance (Green) since the seismic Alert emergency action level (EAL) had been rendered ineffective such that it would not be declared for seismic activity for the OBE vertical acceleration level. The inspectors determined this finding has a cross-cutting aspect in the area in Problem Identification and Resolution, Operating Experience, in that the organization systematically and effectively collects, evaluates and implements relevant external operating experience in a timely manner. The inspectors determined that PSEG staff did not thoroughly evaluate NRC Information Notice (IN) 2012-25, Performance Issues with Seismic Instrumentation and Associated Systems for Operating Reactors, published on February 1, 2013. Specifically, PSEG initiated CAP notification 20594195 in response to IN 2012-025, and took credit for previous actions completed to adjust SC.OP-AB.ZZ-0004, “Earthquake,” but did not account for the vertical direction ground motion acceleration differences between Salem and Hope Creek. [P.5] (Section 1EP6.1)

REPORT DETAILS

Summary of Plant Status

Unit 1 started the inspection period at 98 percent power and reached 100 percent power on April 2. On April 25, the unit was reduced to approximately 55 percent power for planned maintenance on the 12 steam generator feed pump. The unit was returned to 100 percent on April 28. The unit remained at or near 100 percent power for the remainder of the inspection period.

Unit 2 began the inspection period at or near 100 percent power. The unit remained at or near 100 percent power for the remainder of the inspection period.

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, and Barrier Integrity

1R01 Adverse Weather Protection (71111.01 – 1 sample)

Summer Readiness of Offsite and Alternate Alternating Current (AC) Power Systems

a. Inspection Scope

The inspectors performed a review of plant features and procedures for the operation and continued availability of the offsite and alternate AC power system to evaluate readiness of the systems prior to seasonal high grid loading. The inspectors reviewed PSEG's procedures affecting these areas and the communications protocols between the transmission system operator and PSEG. This review focused on changes to the established program and material condition of the offsite and alternate AC power equipment. The inspectors assessed whether PSEG established and implemented appropriate procedures and protocols to monitor and maintain availability and reliability of both the offsite AC power system and the onsite alternate AC power system. The inspectors evaluated the material condition of the associated equipment by interviewing the responsible system manager, reviewing condition reports and open work orders, and walking down portions of the offsite and AC power systems including the 500 kV and emergency diesel generators (EDG).

b. Findings

No findings were identified.

1R04 Equipment Alignment

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

a. Inspection Scope

The inspectors performed partial walkdowns of the following systems:

- Unit 1, 12 control rod drive mechanism vent fan on May 3
- Unit 1, 12 residual heat removal (RHR) while the 11 RHR train was out of service for preventive maintenance on May 28

- Unit 1, 14 and 16 service water during 15 service water planned maintenance on June 16
- Unit 2, 21 and 23 component cooling water during preventive maintenance on the pump suction cross connection valve (2CC18) on June 10

The inspectors selected these systems based on their risk-significance relative to the Reactor Safety cornerstones at the time they were inspected. The inspectors reviewed applicable operating procedures, system diagrams, the UFSAR, TSs, work orders, 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 CAP 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 May 26, the inspectors performed a complete system walkdown of accessible portions of the Unit 2 460 volts alternating current (VAC) and 230 VAC systems to verify the existing equipment lineup was 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, 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

Resident Inspector Quarterly Walkdowns (71111.05Q – 5 samples)

a. Inspection Scope

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

- Unit 1, Holdup tank area on April 3
- Unit 1, Charging pump, spray additive tank area on May 29
- Unit 2, Volume control and boric acid storage tanks on April 3
- Unit 2, Charging pump, spray additive tank area on May 29
- Common, Station blackout air compressor on April 1

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 CAP to determine if PSEG identified and corrected flooding problems and whether operator actions for coping with flooding were adequate. The inspectors focused on the Unit 1 containment spray pump area to verify the adequacy of equipment seals located below the flood line, floor and water penetration seals, watertight door seals, common drain lines and sumps, sump pumps, level alarms, control circuits, and temporary or removable flood barriers. The inspectors also verified that PSEG’s flooding mitigation plans and equipment for the Unit 1, charging pump and spray additive tank areas were consistent with the design requirements and the risk analysis assumptions.

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 April 7 which included a requalification examination and a scenario covering the following major events: a component cooling water leak from the spent fuel pool heat exchanger, a reactor trip demand with no automatic reactor trip, and a post-trip condition with stuck control rods. 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 TS 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 performance of the 1A emergency diesel generator monthly surveillance test on June 29. The inspectors observed test performance to verify 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 – 3 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, CAP documents, maintenance work orders, and maintenance rule (MR) basis documents to ensure that PSEG was identifying and properly evaluating performance problems within the scope of the MR. For each sample selected, the inspectors verified that the SSC was properly scoped into the MR 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 MR system boundaries.

- Unit 1, 12 auxiliary building ventilation exhaust fan damper failed open on March 24
- Unit 2, 25 CFCU SW outlet valve, 25SW72, repeat failures on April 21
- Unit 1 and Unit 2 chiller performance issues on April 23

b. Findings

Introduction. A self-revealing Green NCV of 10 CFR 50, Appendix B, Criterion XVI, “Corrective Action,” was identified when PSEG did not implement corrective actions in a timely manner. Specifically, PSEG identified a degrading trend in the stroke time for the 25 CFCU SW outlet valve, 25SW72, but failed to implement corrective actions to address the trend prior to its failure to stroke in the required time.

Description. One of the functions of the SW system is to act as the ultimate heat sink for heat removed from the containment atmosphere by the CFCUs. The CFCU SW system is a closed system inside containment with a single isolation valve outside containment. Each CFCU SW outlet valve is an air-operated containment isolation valve with an UFSAR designated stroke time requirement of 10 seconds or less. Under PSEG’s IST program, the valve’s acceptable closing stroke time band had been established at 3.1 to 9.3 seconds.

On September 10, 2014, the 25SW72 stroked in 14.6 seconds which exceeded its IST and UFSAR requirements. The ASME OM Code, section ISTC-5133 establishes that pneumatically operated valves that exceed the limiting values of full-stroke time shall be immediately declared inoperable. Operators immediately declared the valve inoperable, entered TS 3.6.3, a 4-hour shutdown limiting condition for operation (LCO) for an inoperable containment isolation valve, and isolated the flowpath. PSEG trouble-shooting identified that the air supply pressure to its air regulator had been set too low for the air volume required to stroke the valve. PSEG adjusted the regulator air and entered this issue in their CAP as notifications 20661667, 20661710, and 20662206.

In October 2012, under work order 30192766, the 25SW72 valve actuator was rebuilt and reinstalled. Subsequently, the valve started to exhibit an adverse trend in stroke times. When it stroked in 8.5 seconds in December 2013, the IST program manager generated notification 20633761 citing a degrading stroke time. In response, PSEG scheduled valve replacement during the Spring 2014 Unit 2 refueling outage under preventive maintenance (PM) work order 30246174. In March 2014, the valve stroked in 8.4 seconds. On April 25, 2014, during the refueling outage, PSEG technicians investigated the valve under the notification, found the open limit switch cam was not free spinning, and adjusted and tightened the cam. The following day, the associated replacement work order was closed with the comment “replacement of S2SW-25SW72 is not required, per CMO Engineering it was replaced 10/12.” In May 2014, the valve showed minimal improvement when it stroked in 8.3 seconds. The valve stroked in 9.0 seconds the following month. Another notification was not written at that time. The valve then failed its stroke time in September as mentioned above.

PSEG performed an evaluation and determined that there were two apparent causes: a) insufficient air pressure and b) insufficient troubleshooting and missed opportunities. PSEG considered the work order closed without sufficient actions, and the June IST surveillance results, as two examples of the latter cause. Inspectors reviewed this issue and determined that while the adverse stroke time trend, a condition adverse to quality, ultimately manifested itself as failure during a surveillance, the issue was self-revealing in that PSEG had missed opportunities to identify and correct the condition during previous quarterly IST surveillances.

Analysis. Failure to implement timely corrective actions was a performance deficiency. The issue was determined to be more than minor since it was associated with the system, structure, or component and barrier performance attribute of the Barrier Integrity cornerstone, and adversely affected its objective to provide reasonable assurance that physical design barriers protect the public from radionuclide releases caused by accidents or events. Specifically, the lack of timely corrective actions ultimately resulted in exceeding the valve's capability to reposition in the IST and UFSAR-required stroke time for containment isolation. The finding was evaluated in accordance with Exhibit 3 of IMC 0609, Appendix A, "The Significance Determination Process for Findings At-Power," issued June 19, 2012, where it screened to very low safety significance (Green) since it was did not represent an actual open pathway in the physical integrity of reactor containment, containment isolation system, and heat removal components, nor did it involve the hydrogen igniter function.

The inspectors determined this finding has a cross-cutting aspect in Human Performance, Teamwork, in that individuals and work groups communicate and coordinate their activities within and across organizational boundaries to ensure nuclear safety is maintained. Specifically, PSEG staff did not collaborate during operational activities such as CAP implementation, work management, and trend analyses to ensure the degrading stroke time was addressed. [H.4]

Enforcement. 10 CFR 50, Appendix B, Criterion XVI, requires, in part, that conditions adverse to quality are promptly identified and corrected. Contrary to this, from December 2013 to September 2014, PSEG did not correct an adverse trend in 25SW72 valve stroke times that ultimately resulted in failing to stroke in the UFSAR and IST required time. PSEG entered this in their CAP (20661667, 20661710, and 20662206) and conducted valve repairs. Because the finding was of very low safety significance (Green) and was entered into PSEG's CAP, it is being treated as an NCV in accordance with Section 2.3.2.a of the Enforcement Policy. **(NCV 05000311/2015002-01, Untimely Corrective Actions for Service Water Outlet Valve)**

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.

- Unit 1, Yellow risk during 12 and 13 chiller emergent unavailability on April 16
- Unit 1, Yellow risk during 1A EDG planned maintenance on May 27
- Unit 1, Yellow risk during 1B EDG planned maintenance on June 4
- Unit 2, Emergent troubleshooting of 21 CFCU and 23 chiller failures on June 3
- Common, Yellow risk during planned control area ventilation maintenance mode configuration on April 20

b. Findings

No findings were identified.

1R15 Operability Determinations and Functionality Assessments (71111.15 – 3 samples)

a. Inspection Scope

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

- Unit 1, 12 chiller tripped on March 27
- Common, Auxiliary feedwater (AFW) storage tank level on April 16
- Common, Surveillance Requirement (SR) 4.0.3 for inadequate airlock equalizing valve leak test on May 8

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

Introduction. A self-revealing Green NCV of 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Action," was identified for PSEG's failure to take timely corrective action to correct a CAQ. Specifically, PSEG failed to replace the 12 chiller motor as a corrective action to address extent of condition following a 13 chiller motor failure in 2008. The 12 chiller subsequently failed on March 27, 2015.

<u>Description</u>. The chilled water system at Salem consists of three 50% capacity safety-related chillers per unit. The safety functions of the chilled water system are to remove sufficient heat loading from the emergency air conditioning units and emergency control air compressors under accident conditions, and remove sufficient heat loading from the main control room air conditioning units under normal operating conditions.

In March 2008, the 13 chiller motor failed. PSEG entered this in their CAP as notification 20361038. PSEG performed an apparent cause evaluation (ACE) under order 70082723 and determined the motor failed due to aging. Specifically, core slot insulation deterioration created looseness and allowed the coils in the slots to vibrate. This resulted in magnet wire insulation deterioration and created a short to the stator core. Grease, dirt, and other contaminants were responsible for the stator core slot insulation deterioration and the shorted condition. This was the result of over greasing bearings and inadequate cleaning of the motor internals at an appropriate interval.

As a corrective action to address the extent of condition for the failed 13 chiller motor in 2008, the 12 chiller motor was scheduled to be replaced in July 2009, based on it having no documented replacement history. PSEG repeatedly deferred the motor replacement until its failure in March 2015, which allowed the motor to be in service for over 17 years. The motor ultimately failed before its latest scheduled replacement date in May 2015. On March 28, 2015, the 12 Chiller breaker tripped on overload. PSEG performed an ACE under order 70175042 and determined the motor failed due to high levels of contamination causing high current draw. A contributing factor to the failure of the motor was inadequate performance of preventive maintenance. For example, PSEG had not performed recommended yearly lubrication of the motor bearings for three years. PSEG's corrective actions included replacing the 12 chiller motor and the stationary and movable contacts in the main contactor panel.

The inspectors concluded that while the PSEG's evaluation of the March 2008 failure of the 13 chiller motor identified a CAQ that existed with all chiller motors, and PSEG had designated corrective actions to replace the motor, PSEG was ultimately not timely with its corrective actions to replace the 12 chiller motor prior to its failure in March 2015. There were numerous opportunities to replace the 12 chiller motor prior to its failure in March 2015.

<u>Analysis</u>. The inspectors determined that PSEG's failure to take timely corrective action to correct a condition adverse to quality was a performance deficiency within PSEG's ability to correct and should have been prevented. This issue was more than minor because it was associated with the equipment performance attribute of the Mitigating System cornerstone, and adversely affected its objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. Specifically, the untimely corrective action resulted in emergent unavailability and associated inoperability of the 12 chiller. The inspectors determined that the finding was of very low safety significance (Green) in accordance with Exhibit 2 of IMC 0609, Appendix A, "The Significance Determination Process for Findings At-Power," dated June 19, 2012, because the finding was not a design or qualification deficiency, did not represent a loss of safety system function, did not represent the loss of function for any TS system, train, or component beyond the allowed TS outage time, and it did not represent an actual loss of function of any non TS trains of equipment designated as high safety significance in accordance with PSEG's maintenance rule program.

The inspectors determined that this finding had a cross-cutting aspect in the area of Problem Identification and Resolution, Resolution, because PSEG did not take effective corrective actions to address issues in a timely manner commensurate with their safety significance. Specifically, PSEG did not replace the motor over a six year period despite having numerous opportunities to replace the 12 chiller motor prior to its failure. [P.3]

Enforcement. 10 CFR 50, Appendix B, Criterion XVI states, in part, that "measures shall be established to assure that conditions adverse to quality, such as failures, malfunctions, deficiencies, deviations, defective material and equipment, and non-conformances are promptly identified and corrected." Contrary to the above, between July 2009 and April 13, 2015, PSEG did not assure that a condition adverse to quality associated with the 12 chiller motor was promptly corrected. PSEG entered this in their CAP as notification 20684871 and replaced the 12 chiller motor. Because this violation was of very low safety significance (Green), and PSEG entered this in their CAP, it is being treated as an NCV in accordance with Section 2.3.2.a of the NRC Enforcement Policy. **(NCV 05000272/2015002-02; Failure to Correct a Condition Adverse To Quality Associated With 12 Chiller Motor)**

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

a. Inspection Scope

The inspectors reviewed the post maintenance tests (PMTs) 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.

- Unit 1, turbine driven auxiliary feedwater auxiliary building support damper (1ABS20) failure on April 1
- Unit 1, 12 chilled water pump motor replacement on April 3
- Unit 1, 1A EDG planned maintenance window on May 28
- Unit 2, 22 chilled water pump discharge valve repack on backseat on May 5
- Unit 2, 21 CFCU relay replacement following a failure to start on June 9

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:

- Unit 1, 12 chilled water pump quarterly surveillance test on April 9
- Unit 1, 11 AFW IST quarterly surveillance test on April 29
- Unit 1, 11 containment spray IST quarterly surveillance test on May 1
- Unit 1, Containment spray chemical additive tank sampling on June 23
- Unit 1, Reactor coolant system leakage (RCS) on June 24
- Unit 2, Steam flow and turbine pressure channel (PT-505) functional test on April 27

b. Findings

No findings were identified.

Cornerstone: Emergency Preparedness

1EP6 Drill Evaluation (71114.06 – 2 samples)

.1 Emergency Preparedness Drill Observation

a. Inspection Scope

The inspectors evaluated the conduct of a routine PSEG emergency drill on May 19, to identify any weaknesses and deficiencies in the classification, notification, and protective action recommendation development activities. The inspectors observed emergency response operations in the simulator and technical support center to determine whether the event classification, notifications, and protective action recommendations were performed in accordance with procedures. The inspectors also reviewed issues related to PSEG's critique to compare inspector observations with those identified by PSEG staff in order to evaluate PSEG's critique, and to verify whether the PSEG staff was properly identifying weaknesses and entering them into the CAP.

b. Findings

Introduction. The inspectors identified a Green NCV of 10 CFR 50.54(q)(2) when PSEG did not maintain an adequate emergency classification and action level scheme that met the planning standards of 10 CFR 50.47(b). Specifically, PSEG did not establish an effective emergency plan with respect to declaring an Alert for seismic activity in excess of an OBE.

<u>Description</u>. In preparations for and following a May 19, 2015, emergency preparedness drill, inspectors reviewed PSEG's emergency plan for seismic activity given the drill scenario. The Salem seismic EALs are an Unusual Event (HU1.1) and an Alert (HA1.1). An Unusual Event is met when two of three conditions are satisfied: an earthquake is felt in plant by control room operators, the SMA-3 event indicator flag is white, and/or the National Earthquake Information Center (NEIC) confirms seismic activity. The Salem SMA-3 flag turns white on seismic activity greater than 0.01g acceleration. An Alert is met when the Hope Creek OBE seismic switch is actuated and verified by the Hope Creek Shift Manager and an earthquake is confirmed by any of the following: when any one of the following is met: an earthquake is felt in plant by control room operators, the NEIC confirms seismic activity, or there is control room indication of degraded performance of a safety system within a provided table.

The inspectors reviewed RG 1.12, "Instrumentation for Earthquakes," Revision 1, April 1974. Section C identifies American National Standards Institute (ANSI) N18.5, "Earthquake Instrumentation Criteria for Nuclear Power Plants," as acceptable for satisfying the seismic instrumentation requirements of 10 CFR 100, Appendix A. ANSI N18.5-1974 describes a seismic switch as one that can provide a remote, immediate signal to indicate if a specified preset acceleration has been exceeded. It continues that such an instrument can provide the basis for an immediate decision following an earthquake. Section 4.4 describes instrumentation requirements at multi-unit sites and states that additional instrumentation at other units will not be required if essentially the same seismic response is expected based on the seismic analysis used in the seismic design of the plant. In this case, the Salem seismic design and response is not the same as described below. Section 6.4.2 states that the seismic switch shall be set to an actuating acceleration in accordance with 10 CFR 100, Appendix A, at 0.05g or the OBE, whichever is greater.

Inspectors reviewed the Salem and Hope Creek EALs and EAL bases, seismic alarm response procedures, seismic abnormal procedures, and UFSARs for information on their OBE and safe shutdown earthquake (SSE). Hope Creek's UFSAR section 3.7.1.1 identifies that site's OBE and SSE as "the maximum ground acceleration values for both horizontal and vertical components of the earthquake are 10 percent and 20 percent of gravity for an OBE and an SSE, respectively." Hope Creek's seismic switch is actuated when a seismic event with a ground acceleration magnitude of greater than or equal to 0.1g (10% of gravity) occurs. Salem's UFSAR section 3.7.1.1 identifies the site's OBE and SSE as a peak horizontal acceleration of 0.10g and 0.20g for the OBE and SSE respectively with two-thirds of the above mentioned values for vertical ground motions (0.067g and 0.13g respectively).

PSEG adopted revised EALs in September 2011 based on NEI 99-01, "Methodology for Development of Emergency Action Levels," Revision 5, in October 2010. Prior to this, PSEG EALs were based on similarly titled NUMARC/NESP-007, Revision 2, dated January 1992. Both indicated than a seismic Alert would be based on an UFSAR seismic event that is greater than the OBE. In the EAL revision request to the NRC, PSEG identified that a valid actuation of the seismic switch is "indication of OBE exceedance independent of analysis of the SGS seismic recorders." Salem's EAL basis for a seismic Unusual Event states, in part, that "this event escalates to an ALERT under EAL HA1.1 if the earthquake exceeds the OBE levels (0.1g)." Salem's EAL basis for a seismic Alert states, in part, that "ground motion acceleration of 0.1g is the OBE for

SGS." Salem's associated abnormal procedure for seismic events, SC.OP-AB.ZZ-0004, "Earthquake," Revision 1, directs in step 3.12 that the plant shutdown "if vibratory ground motion exceeded that of the OBE (>0.1g)." The EAL basis and procedure did not acknowledge the difference in the OBE vertical acceleration value. PSEG entered this issue in their CAP as notification 20691160 and developed a temporary standing order that provided guidance on EAL considerations in case of a seismic event that may require an Alert declaration.

Inspectors determined that seismic activity in excess of Salem's OBE in the vertical direction, but less than the 0.1g in any of the tri-axial directions, would exceed Salem's OBE, but not actuate the Hope Creek seismic switch. In this case, the criteria for a seismic Alert would be met without the proper indication. The inspectors concluded that the difference between Salem's OBE and the Hope Creek seismic switch setpoints rendered PSEG's EAL classification and action scheme ineffective such that it would not be declared for certain seismic activity.

<u>Analysis</u>. PSEG's inadequate emergency classification and action scheme in accordance with 10 CFR 50.47(b)(4) was a performance deficiency. The issue was determined to be more than minor since it was associated with the procedure quality attribute of the Emergency Preparedness cornerstone, and adversely affected its objective to ensure that licensees are capable of implementing adequate measures to protect the health and safety of the public in the event of radiological emergency. Specifically, PSEG would not declare an Alert based on exceeding their OBE without actuating the Hope Creek seismic switch. The issue was reviewed in accordance with IMC 0609, Appendix B, "Emergency Preparedness Safety Significance Determination Process," issued September 26, 2014, where it screened to very low safety significance (Green) since the seismic Alert EAL had been rendered ineffective such that it would not be declared.

The inspectors determined this finding has a cross-cutting aspect in the area in Problem Identification and Resolution, Operating Experience, in that the organization systematically and effectively collects, evaluates and implements relevant external operating experience in a timely manner. The inspectors determined that PSEG staff did not thoroughly evaluate NRC IN 2012-25, Performance Issues with Seismic Instrumentation and Associated Systems for Operating Reactors, published on February 1, 2013. Specifically, PSEG initiated CAP notification 20594195 in response to IN 2012-025, and took credit for previous actions completed to adjust SC.OP-AB.ZZ-0004, "Earthquake," but did not account for the vertical direction ground motion acceleration differences between Salem and Hope Creek. [P.5]

<u>Enforcement</u>. 10 CFR 50.54(q)(2) requires, as a license condition, that licensees follow and maintain the effectiveness of an emergency plan which has capabilities and resources necessary to prepare for and respond to a radiological emergency as set forth in the planning standards of 10 CFR 50.47(b). 10 CFR 50.47(b)(4) requires that the emergency response plan have a standard emergency classification and action scheme. Contrary to 10 CFR 50.54(q)(2) and 10 CFR 50.47(b)(4), since at least September 2011, PSEG did not maintain an adequate emergency classification and action level scheme with respect to declaring an Alert for seismic activity in excess of an OBE. This rendered their EAL ineffective such that it would not be declared for certain seismic activity. PSEG entered this into their CAP (20691160) and developed a temporary Operations standing order. Because this finding was of very low safety significance and was

entered into PSEG's CAP, this violation is being treated as an NCV in accordance with Section 2.3.2.a of the Enforcement Policy. **(NCV 05000272;311/2015002-03, Inadequate Seismic EAL Scheme)**

.2 Emergency Preparedness Training Observation

a. Inspection Scope

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

2. RADIATION SAFETY

Cornerstones: Occupational and Public Radiation Safety

2RS5 Radiation Monitoring Instrumentation (71124.05)

a. Inspection Scope

The inspectors reviewed performance in assuring the accuracy and operability of radiation monitoring instruments used to protect occupational workers and for effluent monitoring and analysis. The inspectors used the requirements in 10 CFR 20, 10 CFR 50, Appendix I; technical specifications; Offsite Dose Calculation Manual (ODCM); RGs; applicable industry standards; and procedures required by TSs as criteria for determining compliance.

Inspection Planning

The inspectors reviewed: PSEG 2013 and 2014 annual effluent and environmental reports; UFSAR; ODCM; Radiation Protection (RP) audits; records of in-service survey instrumentation; and procedures for instrument source checks and calibrations.

Walk-downs and Observations

The inspectors conducted walk-downs of plant area radiation monitors, continuous air monitors and radioactive gaseous effluent monitors. The inspectors assessed material condition of these systems and that the monitor configurations aligned with the ODCM and the UFSAR.

Calibration and Testing Program

The inspectors reviewed calibration and functional testing results for process and effluent monitors (R41, R18, R13) and alarm set-points and changes as applicable (R41, R18, R13). The inspectors reviewed calibration of laboratory gamma spectroscopy instrumentation.

Post- Accident Monitoring

The inspectors reviewed PSEGs capability to collect high-range post-accident iodine effluent samples.

Calibration and Check Sources

The inspectors reviewed the plant waste stream characterization to assess whether the calibration sources used were representative of the radiation encountered in the plant.

Problem Identification and Resolution

The inspectors verified that problems associated with radiation monitoring instrumentation were identified at an appropriate threshold and properly addressed in the corrective action program.

b. Findings

No findings were identified.

2RS6 Radioactive Gaseous and Liquid Effluent Treatment (71124.06)

a. Inspection Scope

The inspectors reviewed: the treatment, monitoring, and control of radioactive gaseous and liquid effluents. The inspectors used the requirements in 10 CFR 20, 10 CFR 50, Appendix I; TS; ODCM; applicable industry standards; and procedures required by TSs as criteria for determining compliance.

Inspection Planning, Event Report Effluent Report Reviews, ODCM and UFSAR Reviews

The inspectors conducted in-office and onsite review of PSEG's 2013 and 2014 annual radioactive effluent and environmental reports, radioactive effluent program documents, effluent monitor operability issues, UFSAR, ODCM, and applicable event reports. The inspectors also reviewed ODCM changes; occurrence of system cross-contamination events, and IE Bulletin 80-10 sampling program.

Ground Water Protection Initiative (GPI) Program and Implementation

The inspectors reviewed: ground water monitoring results, changes to the GPI program, GPI Program Implementation, monitoring results including anomalous results, occurrence of leaks and spills and any associated discharges, updating of ODCM as necessary, and reporting of results. The inspectors reviewed PSEG's evaluation of any positive groundwater sample results, including appropriate stakeholder notifications and effluent reporting requirements.

Walk-downs and Observations

The inspectors walked down the gaseous effluent monitoring systems to assess the material condition and verify proper alignment according to plant design. The inspectors also observed potential unmonitored release points and reviewed radiation monitoring system surveillance records and the routine processing and discharge of gaseous and liquid radioactive wastes. The inspectors observed collection of gaseous effluent samples.

Sampling and Analyses

The inspectors reviewed: radioactive effluent sampling activities and representative sampling requirements; lower limits of detection; compensatory measures taken during effluent discharges with inoperable effluent radiation monitoring instrumentation; and the results of the inter-laboratory and intra-laboratory comparison program including scaling of hard-to-detect isotopes.

Dose Calculations

The inspectors reviewed: changes in reported public dose values from the previous annual radioactive effluent release reports; several liquid and gaseous radioactive waste discharge permits; the scaling method for hard-to-detect radionuclides; ODCM changes; land use census changes; public dose calculations (monthly, quarterly, annual); and records of abnormal gaseous or liquid radioactive releases.

Problem Identification and Resolution

The inspectors evaluated whether problems associated with the radioactive effluent monitoring and control program were identified at an appropriate threshold and properly addressed in PSEG's corrective action program.

b. Findings

No findings were identified.

4. OTHER ACTIVITIES

4OA1 Performance Indicator Verification (71151)

Unplanned Scrams, Unplanned Power Changes, and Unplanned Scrams with Complications (6 samples)

a. Inspection Scope

The inspectors reviewed PSEG submittals for the following Initiating Events Cornerstone PIs for the period of July 1, 2014, through June 30, 2015.

- Unit 1 Unplanned Scrams
- Unit 2 Unplanned Scrams
- Unit 1 Unplanned Power Changes
- Unit 2 Unplanned Power Changes
- Unit 1 Unplanned Scrams with Complications
- Unit 2 Unplanned Scrams with Complications

To determine the accuracy of the PI 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 7. The inspectors reviewed PSEG operator narrative logs, maintenance planning schedules, condition reports, event reports, and NRC integrated inspection reports to validate the accuracy of the submittals.

b. Findings

No findings were identified.

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

.1 Routine Review of Problem Identification and Resolution Activities

a. Inspection Scope

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

b. Findings

Introduction. The inspectors identified a Green NCV of TS 6.12, 'High Radiation Area," when PSEG did not apply appropriate controls to high radiation areas. Specifically, the Unit 1 and 2 reactor cavities, which are areas that exceed 1.0 rem/hour at 30 centimeters, in containment were not properly controlled to prevent unauthorized personnel access.

Description. On a number of occasions, inspectors observed PSEG staff who were not qualified in radiation protection procedures make unescorted containment entries on both units during Mode 1 operations. Containment is normally posted as a High Radiation Area in Mode 1 with a locked cage around the airlock. No guard was posted when the containment airlock is unlocked. While the staff was in containment, the fencing around the personnel airlock remained unlocked and unguarded. Consequently, an individual not qualified in radiation protection, and not authorized to enter a radiation area greater than 1.0 rem/hour at 30 centimeters, could make an unauthorized entry to containment and therefore access the reactor cavity. The inspectors noted that an alarm does sound when the personnel airlock is opened; however, the door alarm would not prevent unauthorized access into containment and the reactor cavity. Radiation levels at the reactor head were estimated by PSEG to be on the order of 100 rem/hr during Mode 1. To understand how the reactor cavity was treated from a radiological perspective during Mode 1 operations, the inspectors interviewed radiation protection staff and walked down the Unit 1 reactor cavity during a forced shutdown in the week of March 14, 2015. Each unit's reactor cavity was surrounded by a handrail that had two swing gates, each locked with a padlock and chain and posted as an "HRA >15 R/hr." An access ladder into the reactor cavity was located at each gate. The highest part of the swing gate was 46 inches high and the lowest horizontal part of the gate was approximately 20 inches high and 20 inches wide. The inspectors questioned PSEG on how this approach complied with TS 6.12 and 10 CFR 20.1601(c). Specifically, the containment airlock and cavity gates did not ensure positive control over personnel access to an HRA.

TS 6.12.2 applies to HRAs with dose rates greater than 1.0 rem/hour at 30 centimeters but less than 500 rads/hour at one meter. It states, in part, "each entryway to such an area shall be conspicuously posted as a high radiation area and shall be provided with a locked or conspicuously guarded door or gate that prevents unauthorized entry." The inspectors also reviewed RG 8.38, "Control of Access to High and Very High Radiation Areas in Nuclear Power Plants," Revisions 0 and 1, to gain insights into what the NRC considered appropriate measures for access control. In Revision 0, section 2.4 describes alternative methods for access control. It states, in part, "each HRA as defined in 10 CFR Part 20, should be barricaded." A note describes a barricade as one that completely surrounds the area and obstructs inadvertent entry. Additionally, the section says that accessible areas that have radiation levels greater than 1.0 rem/hr at 30 cm should be provided with locked doors to prevent unauthorized entry. Revision 1, section 1.5 describes physical controls that may be used to prevent unauthorized personnel access to HRAs. It states, in part, "barriers used to control access to HRAs should provide reasonable assurance that they secure the area against unauthorized access and cannot be easily circumvented," and identified physical barrier examples as chain link fencing or fabricated walls. It discusses that a fence that is 2 meters high would normally be adequate to control access to an HRA. "Openings in physical barriers around an HRA are not required to be controlled as entrances if accessing them requires exceptional measures." Finally, both revisions include direction that when an inaccessible HRA is made accessible, the applicable controls for an HRA must be provided.

Given this information, the controls described in TS 6.12 and informed by RG 8.38 were applicable and required when containment access was unlocked to prevent unauthorized access to the reactor cavity. The swing gates installed at the top of the cavity were not sufficient to prevent unauthorized entry and could be circumvented without exceptional measures. Specifically, the swing gates were significantly less than 2 meters tall, had an accessible area at their base, and were accompanied by ladders that led to the bottom of the cavity. No tools were required to gain access to the HRA. The inspectors concluded that PSEG controls applied to the Unit 1 and 2 reactor cavity HRAs were not adequate to comply with TS 6.12. PSEG entered this issue in their CAP as notification 20682903 and installed 6 foot high scissor gates in both containments to address the concern. With respect to cause, the inspectors determined that PSEG had not sufficiently ensured that staff recognized and planned for the possibility of latent problems, addressed them when discovered, and considered the extent of the condition.

Specifically, opportunities existed for PSEG to identify the inadequate HRA controls when performing containment entries during normal plant operation and when routinely establishing the reactor cavities as locked high radiation areas following refueling outages. Additionally, two Green NCVs were recently identified at Salem for inadequate high radiation area controls. A Green NCV was issued in the second quarter of 2014 (IR 05000311/2014-003 for PSEG's failure to establish and implement adequate radiological controls for the transfer and control of radioactive material within the Unit 2 fuel transfer canal. A second Green NCV was issued in the fourth quarter of 2014 (IR 05000272/2014-005) for inadequate HRA access control.

Analysis. Failure to secure high radiation areas (> 1.0 rem/hour at 30 centimeters) against unauthorized access and ensure personnel control was a performance deficiency. The issue was evaluated in accordance with IMC 0612, Appendix B, and determined to be more than minor since it was associated with the program and process attribute of the Occupational Radiation Safety cornerstone and adversely affected its objective to ensure the adequate protection of the worker health and safety from exposure to radiation from radioactive material during routine civilian nuclear reactor operation. Specifically, high radiation areas with dose rates greater than 1.0 rem/hour at 30 centimeters were not properly controlled to prevent unauthorized personnel access. It was also similar to IMC 0612, Appendix E, example 6.g, in that access to a posted HRA was not controlled in accordance with site TSs, a HRA actually existed, and it was not properly barricaded. The finding was then evaluated using IMC 0609, Appendix C, "Occupational Radiation Safety Significance Determination Process," issued August 19, 2008, where it screened to very low safety significance (Green) since it was not associated with an ALARA issue, did not involve an overexposure, did not constitute a substantial potential for overexposure, and did not compromise PSEG's ability to assess dose.

The inspectors determined this finding has a cross-cutting aspect in the area of Human Performance, Avoid Complacency, in that individuals recognize and plan for the possibility of latent problems, even while expecting successful outcomes. Specifically, PSEG was not sufficiently aware of latent deficiencies in HRA access control given opportunities to identify the inadequate HRA controls when performing containment entries during normal plant operation and when routinely establishing the reactor cavities as locked high radiation areas following refueling outages. [H.12]

Enforcement. TS 6.12.2 describes the controls for high radiation areas with dose rates greater than 1.0 rem/hour at 30 centimeters from the source. TS 6.12.2 states, in part, that "each entryway to such an area… shall be provided with a locked or continuously guarded door or gate that prevents unauthorized entry." Contrary to this, prior to March 27, 2015, PSEG staff did not ensure that the required controls described were followed on Units 1 and 2. PSEG entered this in their CAP as notification 20682903 and installed six foot high scissor fences around each reactor cavity. Because PSEG entered this in their CAP, this is being treated as an NCV in accordance with section 2.3.2.a of the NRC's Enforcement Policy. **(05000272;311/2015002-04, Inadequate HRA Controls)**

.2 Semi-Annual Trend Review

a. Inspection Scope

The inspectors performed a semi-annual review of site issues, as required by Inspection Procedure 71152, "Problem Identification and Resolution," to identify trends that might indicate the existence of more significant safety issues. In this review, the inspectors included repetitive or closely-related issues that may have been documented by PSEG outside of the CAP, such as trend reports, PIs, major equipment problem lists, system health reports, maintenance rule assessments, and maintenance or CAP backlogs. The inspectors also reviewed PSEG CAP database for the first and second quarters of 2015 to assess notifications written in various subject areas (equipment problems, human performance issues, etc.), as well as individual issues identified during the inspector's daily condition report review (Section 4OA2.1). The inspectors reviewed the PSEG CAP trending data, conducted under LS-AA-125, to verify that PSEG personnel were appropriately evaluating and trending adverse conditions in accordance with applicable procedures.

b. Findings and Observations

No findings were identified.

The inspectors determined that any performance deficiencies associated with the trends discussed below were either captured in previous findings (as noted below), or were of minor significance in accordance with IMC 0612, Appendix B.

NRC PI Issues

Inspectors identified a trend of inaccurate NRC PI submittals. Data for these PIs was either inaccurate or non-compliant with NEI 99-02 guidance. All of the issues were determined to be minor following review of IMC 0612, Appendix B, and the NRC Enforcement Manual, and based on none of these issues causing the PI data to exceed any thresholds. Specific examples include:

- Unplanned downpowers
  - PSEG did not submit the unplanned downpower for the November 2014 steam generator feedpump emergency trip (20682142)
  - PSEG did not submit a comment regarding receipt of a notice of enforcement discretion in February 2014 (20686077)
- Mitigating Systems Performance Index (MSPI) – PSEG did not include PMT demands and run time hours, which resulted in invoking the risk cap for 2Q12 through 3Q13 Unit 1 Emergency AC Power (20686786 and 20681932)
- Safety System Functional Failures (SSFF) – PSEG failed to note the licensee event report (LER) number associated with Unit 1 Safety Injection SSFF (20683026)
- RCS Activity – PSEG did not properly report November 2014 data (2061971)
- PI data corrections not properly submitted (20691826)

In response to the station's PI challenges, PSEG performed benchmarking of LS-AA-2001, "Collecting and Reporting of NRC Performance Indicator Data." As a result of the benchmarking, PSEG initiated notifications 20695029 and 20695030 to perform procedure changes.

Overpower Excursions

Dating back to the third quarter of 2014, the inspectors identified a trend of unplanned momentary excursions above rated thermal power (RTP) during Mode 1 operations. The inspectors noted that most of the issues were the result of maintenance activities performed on balance-of-plant drain and level control valves.

- On June 26, 2014, maintenance technicians were not stationed locally at the Unit 1 11 west main steam reheat shell drain and level control valve (11RD60) to perform mitigating actions during controller troubleshooting. Consequently, when the control valve would not open as expected, causing thermal power to rise above RTP. (20655041; NCV 05000272/2014004-01)
- On November 26, 2014, following power ascension on Unit 1, Xenon burn out resulted in an unexpected main control room overhead alarm for the "power range overpower rod stop." T_{avg} rose slightly above program, causing nuclear instrumentation to read slightly above RTP. Operations performed a boration and T_{avg} returned to program. PSEG captured this in CAP under notification 20674518 to conduct a crew learning for monitoring critical parameters and setting operational limits.
- On November 30, 2014, after the Unit 1 'A' main steam reheat drain tank (1A MSRDT) level control valve was returned to service following troubleshooting, Operations received an unexpected alarm, responded to the field and discovered the 11 bleed steam heater drain pump discharge (11HD15) valve open when expected closed. In response, operations tripped the 11 heater drain pump without performing a load drop to 95% in accordance with S1.OP-SO.TD-0001, "Bleed Steam Coil Drain Tank and Heater Drain Pump Operation," which cause thermal power to rise slightly above RTP. (ACE 70172011)
- On January 15, 2015, during Unit 2 26 'C' feedwater heater (FWH) level controller tuning, FWH level rose unexpectedly, causing thermal power to rise slightly above RTP for approximately 1 minute, as well as the 10-minute average thermal power to exceed RTP by 1 megawatt. (ACE 70172852)
- On February 7, 2015, on Unit 2, while on hold at 99.5% RTP following power ascension, Operations received an overhead alarm for the "power range over-power rod stop." This caused all four power range nuclear instruments (NI) read slightly above 100% RTP, and T_{avg} to rise slightly above T_{ref}. Operators inserted control rods to lower reactor power, which cleared the overhead alarm and lowered T_{avg}. A calorimetric was performed and the NIs were adjusted prior to commencing power ascension. (20678169 and QHPI 70173729)
- On June 16, 2015, on Unit 2, after the 23 and 25 feedwater heater bypass control valve (2CN47) was returned to automatic following troubleshooting, the valve received a spurious open signal, causing thermal power to rise approximately slightly above RTP for approximately 1 minute. (20694622, 20694043, 20693951 and 20693950)

The inspectors noted that all of the above issues were captured in CAP. In response, PSEG issued a temporary standing order and standard operating procedure revision to provide additional guidance on controlling RTP during plant secondary drain and level control valve maintenance activities, and reinforced the expectation for conducting the appropriate risk assessments. The inspectors determined all the issues above, with the exception of one previous NCV, screened to minor in accordance with IMC 0612, Appendix B, because the issues did not adversely impact the cornerstone objectives. Specifically, the issues did not challenge critical safety functions (Initiating Events cornerstone), and did not challenge the ability of physical design barriers to protect the public radionuclide release (Barrier Integrity cornerstone). In addition, the inspectors reviewed IMC 0612, Appendix E, and considered other factors that contributed to these issues screening to minor, such as operators promptly lowering thermal power once it was identified that the licensed limit was exceeded, and maximum thermal power never entered an unanalyzed region.

Equipment Reliability

The inspectors identified that an increasing trend of equipment failures was having an apparent impact on the ability of PSEG to meet station CAP goals. Specifically, the inspectors noted that there has been a steady increase in the number of unplanned LCOs (that exceeded station goals) and CAP evaluation products, as well as CAP evaluation products and actions that fell below station goals for quality and timeliness.

PSEG has identified an adverse trend in equipment deficiencies, as evident by the following notifications captured in CAP, dating back to September of 2014.

- 20673666, “Adverse trend in equipment deficiencies,” noted that significant resources are diverted to react to equipment issues.
- 20663477, “NOS ID: 2C14 EOC Equipment Reliability,” was identified by Nuclear Oversight (NOS), and noted that “system engineers do not consistently investigate and resolve repetitive equipment deficiencies and adverse equipment performance trends. The station has experienced repeat issues with significant equipment (Chillers, Condensate Polisher System, Charging positive displace-ment pumps, and Steam Generator Feed Pumps) which has challenged Operations.”
- 20676956, “NOS ID: Manager Concern – Equipment Reliability,” was identified by NOS, and noted “weaknesses in the implementation of the Maintenance Rule, Preventative Maintenance, and Operator Challenges/Burdens Program during 3C14 Assessment and Audit activities. These programmatic shortfalls contributed to the recurring equipment issues.”
- 20676947, “Equipment Reliability Performance Improvement Action Plan,” noted that the station has not thoroughly investigated and resolved repetitive equipment issues.”
- 20685164, “Degrading trend in critical component failures,” noted that the station trend in critical component clock resets and unplanned limiting conditions for operation (LCO) will not meet 2015 year end goals (notification written in April of 2015).
- 20688527, 20687359 and 20680822 capture that PSEG has failed to meet station goals in each month of 2015. Additionally, the inspectors noted that the number of unplanned LCOs has steadily increased on both units since 2013.

The inspectors noted a steady increase in CAP evaluation products since 2013. The inspectors also noted that PSEG identified in several notifications that CAP products were falling below station goals for quality and CA timeliness:

- 20692912, "Action Timeliness Chronic Yellow," noted that the action timeliness goal, for corrective actions generated from CAP causal evaluations, was below goal for March through May of 2015.
- 20692913, "Action Backlog Metric Yellow," noted that corrective actions older than 180 days and generated from CAP causal evaluations were increasing and above the station goal in April and May of 2015.
- 20693338, "ACE Quality Metric Chronic Yellow," noted that Apparent Cause Evaluation monthly score quality was below goal for March through May of 2015.
- 20693341, "CAP Eval Time Metric Yellow," noted that the CAP evaluation timeliness (time to complete CAP evaluations) was below goal in April and May of 2015.
- 20658272, "NOS Elevation Salem Station Timely CA," captured NOS elevation to station management of a continued negative trend in not completing corrective actions associated with NOS identified findings and performance gaps in a timely manner.

The inspectors noted that PSEG has assigned several actions in the engineering department performance improvement plan, as well as the station-wide recovery action plan, to address the adverse trend in equipment reliability. The inspectors determined the adverse trends above were not performance deficiencies in accordance with IMC 0612, Appendix B, because the trends did not represent a failure to meet a requirement or standard.

<u>Inconsistent Assignments of CAP Evaluation Products</u>

The inspectors identified three examples where repeat failures of safety-related equipment did not receive CAP evaluation products (e.g., Root or Apparent Cause Evaluations, etc.), despite previous CAP evaluation products for the same failure:

- 12 Chiller trips
  - No CAP causal evaluation for April 12, 2015 trip (20684871)
  - EQACE 70175042 for trip on March 27, 2015
- 25 CFCU SW outlet valve (25SW72) IST stroke time failures
  - No CAP causal evaluation for December 13, 2014 failed stroke time (20672789)
  - EQACE 70169015 for failed stroke time on September 10, 2014
- CFCU relay failures
  - No CAP causal evaluation for January 14, 2015 failure of 25 CFCU to start (20675624)
  - EQACEs for loss of SW flow to 21 CFCU on July 22, 2014 (EQACE 70168067) and 15 CFCU on May 9, 2013 (EQACE 70154315)

The inspectors reviewed LS-AA-120, "Issue Identification and Screening," Revision 13, Attachment 3, "Guidance for Determining Evaluation Type," and noted the determination process includes a qualitative analysis of risk and uncertainty, and does not require a documented basis for the decision to perform or not perform a CAP evaluation. The inspectors did not identify any performance deficiencies for the failure to perform causal evaluations for the issues above, and noted that all of the individual equipment failures listed above were corrected by PSEG. However, the inspectors determined that repeat failures without an associated CAP evaluation product constituted missed opportunities for PSEG to fully evaluate the causes of equipment failures and take any additional corrective actions as necessary.

Procedure Use and Adherence Trend and Configuration Control

In the 2014 fourth quarter NRC inspection report (IR 05000272;311/2014-005, Section 4OA2.5), inspectors documented an emerging trend in procedure use and adherence (PU&A). The inspectors noted that there was an overall decrease from five to four NRC findings with a cross-cutting aspect in PU&A (H.8) during the previous four rolling quarters, when compared to the 2014 fourth quarter semi-annual trend review (IR 05000272;311/2014-005, Section 4OA2.5). In April 2015, PSEG completed a common cause evaluation of an adverse trend in configuration control (CCE 70173627). PSEG determined that the most prevalent cause was procedure use and adherence.

Specifically, 75% of the events reviewed and 2 of 3 consequential events were from, or enhanced by, less than adequate procedure use and adherence. Corrective actions from this common cause included communicating the results with the applicable station departments, creating department-level dynamic learning activities (DLA), and developing status control computer-based training for all personnel on-site. The inspectors reviewed a March 2015 Root Cause Evaluation in Maintenance Fundamental Behaviors (70170180), operations and engineering department performance improvement plans, as well as the station-wide recovery action plan. The inspectors noted a variety of actions to address inadequate PU&A behaviors, including reinforcing PU&A at pre-job briefs, industry benchmarking on PU&A best practices, manager of the day focused observations in the control room and simulator, change management plans in PU&A and configurations control, procedure revision backlog management, and assessment of all maintenance personnel concerning PU&A and field behaviors through DLAs.

At the close of the inspection period, the inspectors noted that PSEG's corrective actions to address challenges in PU&A were still in the implementation phase. The inspectors determined that although PSEG was taking actions to address the adverse trend in PU&A, multiple examples of lower-level status control and configuration control issues occurred during the SA review period, as indicated below:

- November 30, 2014 – Operations tripped the 11 heater drain pump without performing a load drop to 95% in accordance with S1.OP-SO.TD-0001, "Bleed Steam Coil Drain Tank and Heater Drain Pump Operation." (ACE 70172011)
- January 14, 2015 – Fire Protection isolation valve, 1FP18, found out of position (20675735)
- February 2, 2015 – Unit 1 14 CFCU motor heater found out of position (20677628)
- February 2, 2015 – Level 1 tagging event when station personnel did not adequately determine blocking points prior to performing a partial release on 12 'B' Circulating Water Condenser discharge valve, 12CW126 (20677513)
- February 10, 2015 – Level 2 tagging event when station personnel did not adequately review order operations prior to removing blocking tags from the 12 fuel handling building exhaust fan breaker from the work control document (20678256)

- March 2, 2015 – Water tight door found unsecured (20680283 and NCV 05000272;311/2015001-02)
- March 4, 2015 – Unit 1 chemical fill station supply valve 1FW55 found out of position (20680737)
- March 5, 2015 – Unit 1 Letdown valve to the deborating bed, 2CV205, found out of position (20680744)
- March 2015 – Mispositioning PI Does Not Meet Goal, noted that the six-month rolling goal for component mispositioning on both Units 1 and 2 was below goal in the month of March (20687353)
- May 11, 2015 – 22 chilled water sequencing switch found out of expected position (20689414)
- May 29, 2015 - NOS issued an elevation letter to the station on February 12, 2015, due to an increase in safety tagging events with contributing fundamental behavior gaps in PU&A (20691812)
- June 19, 2015 - Intermediate Range Nuclear Instrument 1N36 Test Mode Switch Found Out of Position (20694228)

Based on the examples above, the inspectors determined that continued action by the station to address PU&A challenges was appropriate. The inspectors determined all the issues above, with the exception of one previous NCV, screened to minor in accordance with IMC 0612, Appendix B, because the issues did not adversely affect any of the cornerstone objectives.

.3 Annual Sample: 12 Safety Injection Pump Breaker Failure to Close

a. Inspection Scope

The inspectors performed an in-depth review of PSEG's evaluations and corrective actions associated with notification 20660365 and ACE 70168725 for an August 27, 2014 failure of the 12 SI pump breaker to close on demand while attempting to refill the 14 SI accumulator. The limiting conditions for operations could not be met as provided in the associated action requirements, because the system had no operable SI pumps available due to the 11 SI pump being out of service for routine maintenance. PSEG realigned, tested, and returned the 11 SI pump into service, then transitioned into TS LCO 3.5.2.b for meeting the action statement of having one SI pump available. PSEG performed an ACE and determined the most probable cause of the failure was due to the lack of lubrication inside the breaker close latch roller. The apparent cause was determined to be not proactively addressing timely overhauls of the breakers.

The inspectors assessed PSEG's problem identification threshold, problem analysis, extent of condition reviews, compensatory actions, and the prioritization and timeliness of PSEG's corrective actions to determine whether PSEG was appropriately identifying, characterizing, and correcting problems associated with this issue and whether the planned or completed corrective actions were appropriate. The inspectors compared the actions taken to the requirements of PSEG's corrective action program and 10 CFR 50, Appendix B, Criterion XVI, "Corrective Action" and 10 CFR 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings."

b. Findings and Observations

The inspectors concluded that PSEG took appropriate actions to identify the cause of the August 27, 2014, 12 SI pump breaker failure. The inspectors determined that the breaker failure was due to inadequate overhaul intervals of the 4kV breakers.

During review of the 12 SI pump breaker trip event, the inspectors noted that the breaker's recent operating history had, in effect, changed its classification under PSEG's ER-AA-1001, "Component Classification," Revision 2. Specifically, the breaker had originally been classified as a critical, low duty cycle, mild environment component. However, inspectors noted that a high duty cycle was defined, in part, as one where the component is cycled frequently (i.e. greater than two times per week). From late 2014, the 14 accumulator had been experiencing leakage. From that time through the first half of 2015, the frequency at which the 12 SI pump was started to refill the accumulator steadily rose. In the few months leading up the failure, the number of accumulator fills with the 12 SI pump increased until its usage was three times a week for the two weeks prior to the failure. Essentially, PSEG had changed the breaker's classification by changing its operational frequency to compensate for accumulator leakage. A review of PSEG's maintenance template for the same breaker as a high duty cycle component was the same as that for a low cycle breaker. Therefore, the inspectors concluded that this issue was minor. However, they also concluded that PSEG missed this as an opportunity to identify a change in the circumstances surrounding the breaker's operation. PSEG captured this in their CAP as notification 20664925.

Introduction. A self-revealing Green NCV of 10 CFR 50, Appendix B, Criterion V, "Instruction, Procedures, and Drawings," was identified because PSEG did not establish an appropriate interval to overhaul 4kV GE Magne-Blast breakers. As a result, the safety-related breakers for the 12 safety injection pump and 11 CCW pump were operated beyond the industry recommended overhaul interval and subsequently failed.

Description. On August 27, 2014, the 12 SI pump failed to start while implementing procedure S1.OP-SO.SJ-0002, "Accumulator Operations", when preparing to fill the 14 SI accumulator. The 11 SI Pump was in the process of being tagged out to perform scheduled maintenance on the 11 SI pump discharge check valve, 11SJ34. When the operator pushed the start button for the 12 SI pump, the associated stop button immediately began to backflash and no indications were received in the control room. The shift manager reported smoke coming from the 12 SI pump breaker vents and as soon as the control power breaker was opened the shift manager reported that the smoke began to dissipate. The control room crew entered TS LCO 3.0.3 for no operable SI pumps. PSEG realigned, tested, and returned the 11 SI pump into service and then subsequently transitioned to TS LCO 3.5.2.b for only one operable SI pump.

PSEG performed an ACE and determined the apparent cause of the 12 SI pump breaker failure to close on demand was due to not addressing timely overhauls of the breakers. GE completed a failure analysis of the breaker and determined the most probable cause of failure was the lack of lubrication inside the close latch roller. The lack of lubrication caused an increase in friction, which prevented the closing coil from rotating the close latch from under the closing latch roller. This resulted in the closing coil remaining energized for an extended period of time until it ultimately failed due to overheating. During the 54 month PM, the exterior of the close latch roller is lubricated per procedure

SC.MD-IS.4KV-0001, "4KV and 13KV Magne-Blast Circuit Breakers Inspection and Test." GE does not require lubrication of the interior of the close latch roller during a PM because it involves extensive disassembly to access. The breaker overhauls are performed by outside vendors. PSEG confirmed that lubrication of this component is performed during the overhaul process. A breaker overhaul is a complete disassembly to give access to all parts for cleaning, inspection for damage and wear, and complete replacement of lubricant. The 12 SI pump breaker was last overhauled in 1996 and was due for its 16 year overhaul in December 2015 per PSEG's work schedule. The breaker overhaul was delayed due to a limited number of spare breakers available.

The PSEG performance centered maintenance (PCM) template process utilizes internal and external operating experience and component history to develop recommended preventive maintenance activities. MA-AA-716-210, "Preventive Maintenance Program," requires that the PCM templates are periodically reviewed, and when applicable updated based on revised EPRI guidance, and internal and external operating experience. The inspectors reviewed ACE 70168725 and determined that PSEG took appropriate corrective actions; however, the failure could have been prevented if PSEG had completed overhauls on the 4kV breakers at EPRI's recommended interval of 8-12 years. The NRC identified that PSEG did not have a basis for the 16 year overhaul frequency. PSEG completed several corrective actions which included replacing the 12 SI pump breaker, replacing the Unit 2 group bus breakers and having spares to send out for overhauls, ensuring the closing coil is replaced in the overhaul, and reducing the PM frequency to 12 year overhauls.

During completion of the corrective actions, an additional breaker failure occurred on the 11 CCW pump breaker on November 16, 2014. The inspectors reviewed notification 20671015 in which the 11 CCW pump breaker opened, but the charging springs were found discharged when they should have been charged. The failure mechanism of the 11 CCW pump breaker was binding of the closing coil plunger, which caused the close latch monitor switch to partially open. The breaker was removed from service and replaced with a newly overhauled breaker. PSEG determined the cause of the 11 CCW pump breaker was the same as the 12 SI pump breaker, which was due to not addressing timely overhauls of the breakers, although the failure mechanism was different.

Analysis. The performance deficiency associated with this finding was that PSEG did not establish an appropriate interval to overhaul the 4kV GE Magne-Blast breakers. This finding is more than minor because it is associated with the equipment performance attribute of the Mitigating Systems cornerstone and adversely affected the cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. Specifically, PSEG did not consider industry recommendations nor develop a basis when establishing 4kV GE Magne-Blast breaker overhaul intervals, which resulted in failure of the 12 SI pump and 11 CCW pump breakers. In accordance with IMC 0609.04, "Initial Characterization of Findings," and Exhibit 2 of IMC 0609, Appendix A, "The Significance Determination Process for Findings At-Power," issued June 19, 2012, the inspectors determined that the finding was of very low safety significance (Green), because the finding was not a deficiency affecting the design or qualification of the mitigating system; it did not represent a loss of system function; it did not represent the loss of function for any TS system, train, or component beyond the allowed TS outage time; and it did not represent an actual loss of function of any non TS trains of equipment designated as high safety significance in accordance with PSEG's maintenance rule program.

This finding has a cross-cutting aspect in the area of Problem Identification and Resolution, Operating Experience, because PSEG did not systematically and effectively collect, evaluate, and implement relevant internal and external operating experience in a timely manner. Specifically, the overhaul frequencies assigned to safety-related 4KV breaker inspections were inadequate to ensure the breakers would operate properly. [P.5]

Enforcement: 10 CFR 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings" states in part, that activities affecting quality shall be prescribed by documented instructions, procedure, or drawings, of a type appropriate to the circumstances and shall be accomplished in accordance with these instruction, procedures, or drawings. PSEG procedure MA-AA-716-210, "Preventive Maintenance Program," requires that the PCM templates are periodically reviewed, and when applicable, updated based on revised EPRI guidance and internal and external operating experience. Contrary to the above, on August 27, 2014, PSEG did not establish an appropriate interval to overhaul 4kV GE Magne-Blast breakers to ensure that the breakers would operate when called upon. As a result, the safety-related breakers for the 12 SI pump and 11 CCW pump were operated beyond the industry recommended overhaul interval and subsequently failed. PSEG's corrective actions included replacing the 12 SI pump and 11 CCW pump breakers, and reducing the overhaul PM frequency to 12 years. Because this violation was of very low safety significance (Green) and it was entered into the PSEG CAP as notifications 20660365 and 20671015, this violation is being treated as a NCV, consistent with Section 2.3.2.a of the NRC Enforcement Policy. **(NCV 05000272/2015002-05, Failure to Establish Appropriate Breaker Preventive Maintenance Periodicity)**

.4 Annual Sample: Failure of 1B Vital Instrument Bus (VIB) results in Loss of Safety Function

a. Inspection Scope

The inspector performed an in-depth review of PSEG staff's evaluations and the effectiveness of the corrective actions associated with the failure of the 1B VIB on October 29, 2014 at Salem Unit 1.

The inspector performed an in depth review of the ACE, and maintenance rule evaluations. The inspector assessed PSEG's evaluations, extent of condition review, completed and proposed corrective actions, and the prioritization and timeliness of actions to evaluate whether the corrective actions were appropriate.

PSEG made an Event Notification (EN) 50573 on October 29, 2014, due to the loss of safety function associated with the control room emergency air conditioning system (CREACS). EN 50573 was later retracted by PSEG. The inspector reviewed the technical aspects and appropriateness of the retraction.

The inspector also interviewed operators and evaluated the appropriateness of the determination that the CREACS was operable but degraded due to manually opening the inlet dampers with the loss of the 1B VIB.

b. Findings and Observations

No findings were identified.

The inspector determined that PSEG's evaluation and extent of condition review were thorough, and the causes appropriately identified. The inspectors also determined that the corrective actions were reasonable and address the maintenance rule requirements for repeat maintenance preventable functional failures.

The inspector reviewed equipment ACE 70170868 for the 1B inverter, as well as ACE 70166610 for the 1C inverter failure in May 2014. Based on these two successive failures, PSEG determined that this was a repeat maintenance preventable functional failure and therefore an (a)(1) evaluation plan was required. At the time of the inspection, PSEG was in progress with the maintenance rule (a)(1) evaluation plan for the inverters, including development of the corrective actions and monitoring plan required to return the system to (a)(2) status. The inspector also reviewed the ACE 70170868 corrective actions that were assigned but not yet completed. The inspector noted that the vendor failure report was not completed at the time of the inspection. The inspector determined that the assigned corrective actions were appropriate to the circumstances at the time of inspection.

PSEG's subsequent review of the condition reported on October 29, 2014, in EN 50573 determined that the CREACS was operable and capable of performing its safety function. Therefore, there was no reportable condition. Circuit analysis identified that the Unit 2 control room intake isolation train B circuit remained fully functional and able to respond to a Unit 2 SI signal or actuation from radiation monitor 2R1B Channel 1 (radiation levels in the Unit 2 normal control area ventilation intake). The loss of the 1B vital instrument bus did not affect the normal actuation circuitry. The appropriate Unit 1 dampers would have received an open signal and the appropriate Unit 2 dampers would have received a close signal, thereby isolating the Unit 2 CREACS intake and opening the Unit 1 CREACS intake. Thus, the CREACS would have been capable of mitigating the consequences of an accident. The inspector reviewed PSEG's evaluation and the circuits and concluded that the retraction was appropriate.

Finally, the inspector reviewed the operability determination for operating the CREACS system with the inlet dampers manually open. The inspector noted that the evaluation did not document how the technical specification SRs were met for the "Fire Outside Control Area" function of the dampers while they were pinned manually in the open position. PSEG provided to the inspector additional information that documented that the 1CAA50 and 1CAA51 dampers did not have to automatically close to meet the acceptance criteria of the technical specification surveillance.

.5 Annual Sample: Chiller Water System Evaporator Gasket Leakage

a. Inspection Scope

The inspectors performed an in-depth review of PSEG's evaluations and corrective actions associated with chilled water system evaporator gasket leaks. The inspectors assessed PSEG's problem identification threshold, cause analysis, extent-of-condition reviews, and the prioritization and timeliness of corrective actions to evaluate whether PSEG was appropriately identifying, evaluating, and correcting problems associated with this issue and whether the planned and/or completed corrective actions were appropriate. The inspectors compared the actions taken to the requirements of PSEG's CAP, PSEG's operability assessment and equipment control program, and Salem TSs. The inspectors performed a walkdown of the accessible portions of the chilled water system to independently assess operational performance, and the ability of PSEG to identify issues at a low threshold. Additionally, the inspectors discussed system performance issues with engineering, maintenance and operations personnel.

The chilled water system at Salem consists of three 50% capacity safety-related chillers per Unit. The safety functions of the chilled water system are to remove sufficient heat loading from the emergency air conditioning units and emergency control air compressors under accident conditions, and remove sufficient heat loading from the main control room air conditioning units under normal operating conditions. The chilled water system operates on a basic refrigeration cycle, whereby refrigerant circulates in a closed loop from the discharge of a compressor into the shell side of a condenser, then through a thermostatic expansion valve and into the tube side of an evaporator, then back to the compressor suction. The chilled water system evaporator is a shell and U-tube heat exchanger, with refrigerant on the tube side and service water on the shell side. The evaporator is designed with bolted-gasket head connections for evaporator tube access. The gasket located at the common tube inlet / outlet head is designed with a divider plate, which separates liquid refrigerant at the tube inlet from refrigerant gas at the tube outlet. The opposing end of the evaporator, or turnaround head, is also designed with a gasket-style connection.

b. Findings and Observations

Introduction. The inspectors identified a Green NCV of TS 6.8.1, "Procedures and Programs," as described in Regulatory Guide 1.33, Revision 2, February 1978, when PSEG performed chiller water system maintenance activities that were not properly preplanned in accordance with documented instructions, resulting in multiple chiller system trips on both units. Specifically, PSEG maintenance procedure SC.MD-PM.CH-0001, "ACME Chiller Compressor Inspection and Repair," did not incorporate documented instructions from the vendor technical document.

Description. On December 4, 2014, 21 chiller tripped on freeze protection, which placed Unit 2 in Technical Specification required action 3.7.10.a and required the station to restore 21 chiller to operable within 14 days, or be in Mode 3 within 6 hours. PSEG performed troubleshooting and identified refrigerant leakage across the evaporator head gasket divider plate, performed corrective maintenance to replace the gasket, and restored 21 chiller to operable on December 14, 2015. PSEG determined that leakage across the divider plate resulted in cold liquid refrigerant migrating from the U-tube inlet side of the evaporator head divider plate to the gaseous refrigerant phase on the tube outlet side, sufficiently lowering the gas temperature at the compressor inlet to cause a trip on freeze protection. PSEG performed ACE 70171934 and determined that the cause of the divider plate gasket leakage was attributed to inadequate chiller maintenance procedure instructions for performing divider plate gasket installation. Specifically, chiller maintenance procedure SC.MD-PM.CH-0001, "ACME Chiller Compressor Inspection and Repair," did not incorporate detailed vendor manual instructions for performing divider plate gasket installation. The inspectors noted that corrective actions in ACE 70171934 credited revisions to chiller maintenance procedure SC.MD-PM.CH-0001 that were previously performed as corrective actions (CAs) under root cause evaluation (RCE) 70169007, completed on December 8, 2014. RCE 70169007 identified refrigerant leaks at both the turnaround and divider plate ends of the 13 chiller evaporator following a low suction pressure trip on August 3, 2014. PSEG determined that the effect of 13 chiller refrigerant leakage from the turnaround head gasket, when combined with low compressor inlet temperature due to leakage across the divider plate head gasket, resulted in the low suction pressure trip of the compressor.

The inspectors identified several discrepancies in ACE 70171934 and RCE 70169007, and associated CAs:

- In ACE 70171934, the inspectors identified that PSEG's apparent cause statement incorrectly described the turnaround head gasket as the cause of the 21 chiller trip. The inspectors also identified that the divider plate and turnaround head gasket terminology was used interchangeably throughout the body of the ACE, despite physical differences between gasket design and installation instructions. PSEG captured these discrepancies in notification 20694194.
- In RCE 70169007, the inspectors identified that the completed chiller maintenance procedure SC.MD-PM.CH-0001 corrective action revisions did not incorporate detailed vendor manual instructions to differentiate between divider plate and turnaround head gasket installation, despite leakage identified on both evaporator head gaskets that resulted in a trip of the 13 chiller. PSEG captured this discrepancy under notification 20692452.
- The inspectors identified that the completed procedure SC.MD-PM.CH-0001 corrective action revisions did not include existing vendor manual instructions to perform bolt re-torque checks 24-48 hours following initial head gasket bolt torque. Additionally, vendor manual instructions stated that 5 torque passes were required on the gasket bolts, while the revised chiller maintenance procedure stated to only perform 3 torque passes. When the inspectors questioned PSEG engineering and maintenance personnel if the different installation instructions had been previously considered or evaluated, PSEG did not provide an explanation for the differences. PSEG captured these discrepancies in notification 20692457.
- The inspectors identified that gasket replacement work order (WO) instructions lacked relevant detail, which had the potential to result in repeat problems and future re-work. PSEG captured these WO detail discrepancies under notification 20694194. Specifically:
    - ACE 70171934 CA to perform extent of condition (EOC) gasket replacements on the remaining chillers created WOs to replace the head gaskets on the four remaining chillers using the newly revised procedure SC.MD-PM.CH-0001, but did not specify which head gaskets (e.g., divider plate or turnaround head) to replace.
    - EOC assignments for ACE 70171934 credited previous replacement of the 21 chiller turnaround head center staybolt gasket, which used the vendor installation instructions, following the December 4, 2014 trip. Subsequently, on April 28, 2015, PSEG identified a large leak at the 21 chiller turnaround head center staybolt. During planned corrective maintenance (CM) to repair the large leak, the CM WO described the as-found gasket as cracked and leaking, but did not describe why the vendor installation steps contained in SC.MD-PM.CH-0001 were unsuccessful in December 2014, nor did the CM WO describe any changes or enhancements to the installation steps.

The inspectors determined that the issues identified above constituted previously unknown weaknesses in PSEG's classification, evaluation, and corrective actions associated with the evaporator head gasket leaks. Therefore, the inspectors considered this finding to be NRC-identified in accordance with IMC 0612.

The inspectors performed a CAP search for additional chiller evaporator gasket leaks. The inspectors noted ACE 70132535, completed March 5, 2012, was performed in response to two trips of the 22 chiller that were attributed to inadequate installation of the divider plate gasket. CAs included a revision to SC.MD-PM.CH-0001 to include guidance for use of an adhesive during divider plate gasket installation. The inspectors noted that there were no ACE actions to review the chiller evaporator vendor manual, obtained by PSEG as early as 2003, for detailed gasket installation instructions to incorporate into SC.MD-PM.CH-0001. Additionally, PSEG determined that no EOC actions were needed on the five other chiller divider plate gaskets, because the other chillers were operating satisfactorily at the time. The inspectors concluded the 2012 ACE represented a missed opportunity to address the inadequate maintenance procedure SC.MD-PM.CH-0001 instructions for gasket installation.

Analysis. The inspectors determined that PSEG's failure to perform maintenance activities on the safety-related chillers in accordance with documented instructions was a performance deficiency. This finding was more than minor because it was associated with the equipment performance attribute of the Mitigating System cornerstone, and adversely affected the cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. Specifically, failure to install the chiller evaporator gasket in accordance with written instructions from the vendor manual resulted in four chiller failures since 2011. Using IMC 0609, Attachment 4, "Initial Characterization of Findings," and Exhibit 2 of IMC 0609, Appendix A, "The Significance Determination Process for Findings At-Power," dated June 19, 2012, the inspectors determined that this finding was of very low safety significance (Green) because the finding was not a design or qualification deficiency, did not represent a loss of safety system function, did not represent the loss of function for any TS system, train, or component beyond the allowed TS outage time, and it did not represent an actual loss of function of any non TS trains of equipment designated as high safety significance in accordance with PSEG's maintenance rule program.

This finding had a cross-cutting aspect in the area of Problem Identification and Resolution, Evaluation, in that licensees thoroughly evaluate issues to ensure that resolutions address causes and extent of conditions commensurate with their significance. Specifically, PSEG did not thoroughly evaluate chiller divider plate head gasket failures in 2012, such that the resolution addressed the inadequate maintenance procedure instructions. [P.2]

Enforcement. TS 6.8.1, "Procedures and Programs," states, in part, that "written procedures shall be established, implemented and maintained covering the applicable procedures recommended in Appendix 'A' of Regulatory Guide (RG) 1.33, Revision 2, February 1978." RG 1.33, Rev.2, February 1978, Section 9, "Procedures for Performing Maintenance," states, in part, that "maintenance that can affect the performance of safety-related equipment should be properly preplanned and performed in accordance with written procedures, documented instructions, or drawings appropriate to the circumstances." Contrary to the above, from March 5, 2012 to April 1, 2015, PSEG maintenance procedure SC.MD-PM.CH-0001, "ACME Chiller Compressor Inspection and Repair," was not established, implemented and maintained covering the applicable maintenance that can affect the performance of the safety-related chilled water system equipment. Specifically, SC.MD-PM.CH-0001 was not properly preplanned and performed in accordance with documented instructions in vendor technical document 325458, "Chilled Water Evaporator Vendor Manual," including the required gasket material and thickness, instructions for surface cleaning and cementing, and instructions for the required bolt torque values and torque pattern. Consequently, evaporator head gasket replacement was not properly preplanned and performed, which resulted in multiple chiller failures. PSEG performed an ACE 70171934, and revised the maintenance procedure that included detailed vendor instructions. Because this finding was of very low safety significance and was entered into PSEG's CAP via notification 20672732, this violation is being treated as an NCV consistent with Section 2.3.2.a of the NRC's Enforcement Policy. **(NCV 05000272; 311/2015002-06, Inadequate Chiller Maintenance Procedure)**

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

(Closed) 05000272/2014-005-00: Loss of Safety Function Resulting from Safety Injection Pump Breaker Failure

a. Inspection Scope

The inspector's reviewed PSEG's actions and reportability criteria associated with LER 05000272/2014-005-00, which was submitted to the NRC on October 21, 2014. On August 27, 2014, the 11 SI pump was being tagged out for planned maintenance. At 2:43 a.m., the 11 SI pump was declared inoperable. At 2:48 a.m., the 12 SI pump failed to start on demand when operators were attempting to fill the 14 SI Accumulator. The unit entered TS 3.0.3 for inoperability of two SI pumps. At 3:01 a.m., the 11 SI pump was realigned, tested and returned to service and the unit exited TS 3.0.3. The apparent cause of the 12 SI pump failure to start was due to a lack of timely breaker overhauls which would have provided adequate lubrication of the close latch roller. The inspectors reviewed the LER, the associated apparent cause evaluation analysis, and interviewed PSEG staff. This LER is closed.

b. Findings

The inspectors documented a Green NCV of 10 CFR 50, Appendix B, Criterion V associated with this issue in Section 4OA2.3 of this report.

4OA5 Other Activities

.1 Correction to Inspection Report 2015-001

During a review of Inspection Report 05000272;311/2015-001, an error in the number of samples documented in section 1R11 was identified. The correct number of samples was two based on quarterly reviews of both licensed operator requalification and performance in the control room versus one as listed. Given the administrative nature of this correction, this entry is made in accordance with IMC 0612 section 15.04.

.2 Institute of Nuclear Power Operations (INPO) Report Review

a. Inspection Scope

The inspectors reviewed the final report for the INPO plant assessment of PSEG conducted in August 2014. The inspectors evaluated this report to ensure that NRC perspectives of PSEG performance were consistent with any issues identified during he assessment. The inspectors also reviewed this report to determine whether INPO identified any significant safety issues that required further NRC follow-up.

b. Findings

No findings were identified.

4OA6 Management Meetings

Exit Meeting Summary

On July 9, 2015, the inspectors presented the inspection results to Mr. John Perry, Salem Site Vice President, 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

<u>Licensee Personnel</u>
J. Perry, Site Vice President
L. Wagner, Plant Manager, Salem
C. Aung, Chemistry Engineer
T. Bashore, Nuclear Oversight Assessor
S. Bowers, Maintenance Rule Program Coordinator
T. Cachaza, Regulatory Assurance
R. Cary, Environmental Coordinator
B. Daly, Manager, Sustainability, Environmental Affairs
J. Donovan, System Engineer
K. Grover, Engineering Director
A. Kraus, Manager, Nuclear Environmental Affairs
D. LaFleur, Regulatory Assurance
L. Oberembt, System Manager
T. Sexsmith, Regulatory Assurance
J. Stead, Senior Plant Engineer
S. Taylor, Radiation Protection Manager
B. Thomas, Principal Engineer
R. Truhan, Nuclear Oversight Manager
K. Tuccilo, Supervisor, Nuclear Engineer Environmental Engineering Section, State of New Jersey
J. Vouglitois, Nuclear Engineer, Nuclear Environmental Engineering Section, State of New Jersey

LIST OF ITEMS OPENED, CLOSED AND DISCUSSED

<u>Open and Closed</u>

05000311/2015002-01	NCV	Untimely Corrective Actions for Service Water Outlet Valve (Section 1R12)
05000272/2015002-02	NCV	Failure to Correct a Condition Adverse To Quality Associated With 12 Chiller Motor (Section 1R15)
05000272;311/2015002-03	NCV	Inadequate Seismic EAL Scheme (Section 1EP6.1)
05000272;311/2015002-04	NCV	Inadequate HRA Controls (Section 4OA2.1)
05000272/2015002-05	NCV	Failure to Establish Appropriate Breaker Preventive Maintenance Periodicity (Section 4OA2.3)

05000272;311/2015002-06	NCV	Inadequate Chiller Maintenance Procedure (Section 4OA2.5)

Closed

05000272/2014-005-00	LER	Loss of Safety Function Resulting from Safety Injection Pump Breaker Failure (Section 4OA3)

LIST OF DOCUMENTS REVIEWED

* Indicates NRC-identified

Section 1R01: Adverse Weather Protection

Procedures
S1.OP-AB.LOOP-0001, Loss of Off-Site Power, Revision 29
S2.OP-AB.LOOP-0001, Loss of Off-Site Power, Revision 29
SC-OP-PT.ZZ-0002, Station Preparations for Seasonal Conditions, Revision 12
WC-AA-107, Seasonal Readiness, Revision 13

Notifications
20661964

Other Documents
PJM Manuals M-1, M-3, M-13, and M-39

Section 1R04: Equipment Alignment

Procedures
OP-AA-108-116, Protected Equipment Program, Revision 10
S1.OP-SO.SW-0005, Service Water System Operation, Revision 39
S1.OP-ST.SW-0013, Service Water Valve Verification Modes 1-4, Revision 1
S2.OP-SO.CC-0001, Component Cooling System Operation, Revision 16

Notifications
20691698* 20691701* 20693833 20693938

Drawings
203061, 4160V Vital Busses One-Line, Revision 34
203063, 460V & 230V Vital & Non Vital Bus One Line Control, Revision 37
205242, No. 1 Unit Service Water Nuclear Area, Sheet 2, Revision 90
205331, No. 2 Unit Component Cooling, Sheet 1, Revision 54
205332-SIMP, Sheet 1, No. 2 Unit Residual Heat Removal Simplified P&ID, Revision 2
222510, 2C Ventilation 230V Vital Control Center One-Line, Revision 27

Maintenance Orders/Work Orders
50175922

Other Documents
Salem Unit 1 Risk Assessment for June 14, 2015, through June 20, 2015, Revision 0
Salem Unit 2 Risk Assessment for June 7, 2015, through June 13, 2015, Revision 0

Section 1R05: Fire Protection

Procedures
FP-SA-1534-F1, Unit 1 Holdup Tank Area, Revision 0
FP-SA-1544-F1, Unit 1 Charging Pump and Spray Additive Tank Area, Revision 0
FP-SA-2563-F1, Unit 2 Volume Control and Boric Acid Tanks, Revision 0
FP-SA-2544-F1, Unit 2 Charging Pump and Spray Additive Tank Area, Revision 0
FP-SA-2853-F1, Common - Blackout Air Compressor Building, Revision 0
S2.FP-ST.FD-0029(Q), Smoke and Thermal Detector Functional Test, Revision 14
SC.OP-PT.CA-0001(Q), SBO Diesel Control Air Compressor test, Revision 13

Notifications
20683910* 20684183* 20684130* 20685441*

Section 1R06: Flood Protection Measures

Notifications
20675238 20675239 20675240 20675242 20675260 20677379

Procedures
S1.OP-AB.SW-0001, Unit 1 Loss of Service Water Header Pressure, Revision 17
S1.OP-AR.ZZ-0002, Unit 1 Overhead Annunciators Window B, Revision 28
SC.FP-SV.FBR-0026, Flood and Fire Barrier Penetration Seal Inspection, Revision 6

Other Documents
NRC Information Notice 2005-11, Internal Flooding/Spray-Down of Safety-Related Equipment Due to Unsealed Equipment Hatch Floor Plugs and/or Blocked Floor Drains
SA-PRA-012, Internal Flood Evaluation Summary Notebook, Revision 0

Section 1R11: Licensed Operator Requalification Program

Procedures
2-EOP-TRIP-1, Reactor Trip or Safety Injection, Revision 28
2-EOP-TRIP-2, Reactor Trip Response, Revision 28
S1.OP-ST.DG-0001, 1A Diesel Generator Surveillance Test, Revision 46
S2.OP-AB.CC-0001, Component Cooling Abnormality, Revision 14

Notifications
20688507*

Maintenance Orders/Work Orders
50175334 50177099

Other Documents
Simulator Training Scenario S-ESG-1502, Revisions 0 and 1

Section 1R12: Maintenance Effectiveness

Procedures
SC-MSPI-001, Salem Generating Station Nuclear Regulatory Commission Regulatory Oversight Process Mitigating System Performance Index Basis Document, Revision 10
ER-AA-310-1001-F1, Maintenance Rule Scoping Change Request Form, Revision 0
ER-SA-310-1009, Salem Generating Station – Maintenance Rule Scoping, Revision 5

Notifications

20453613	20460584	20579352	20633761	20661667	20661710
20662206	20672789	20674313	20676775	20676930	20682696
20686861*	20687785*	20688687*	20692342	20694666*	20694935*

Maintenance Orders/Work Orders

30192766	30246174	50140821	60119046	70169015	70172461
70173191	70173261	70174720	70177400		

Section 1R13: Maintenance Risk Assessments and Emergent Work Control

Procedures
OP-AA-101-112-1002, On-Line Risk Assessment, Revision 9
OP-AA-108-116, Protected Equipment Program, Revision 10
OP-SA-108-115-1001, Operability Assessment and Equipment Control Program, Revision 7
SC.ER-PS.FP-0001-A4, Fire Events in Maintenance Rule (a)(4) Risk Evaluations, Revision 0
WC-AA-101, On-Line Work Management Process, Revision 23

Notifications

20685542*	20685996	20686163*	20687191*	20692414	20692554

Maintenance Orders/Work Orders
50176054

Other Documents
S-C-ABV-MEE-0508, Effect of Loss of Ventilation on Operation of Safe Shutdown Equipment as Postulated by a 10 CFR 50 Appendix R Fire, Revision 0
Salem Unit 1 Risk Assessment for Work Week 522 - May 24, 2015, through May 30, 2015, Revision 0

Section 1R15: Operability Determinations and Functionality Assessments

Procedures
LS-AA-120, Guidance for Determining Evaluation Type, Revision 13
LS-AA-125-F1, MRC Review Guidance, Revision 4
LS-AA-125-F3, MRC Change Request, Revision 1
MA-AA-716-008, Attachment 3, Work Package Forms, FME Drop Log and Signs, Revision 6
MA-AA-716-230-1002, Vibration Analysis/Acceptance Guidelines, Revision 3
MA-AA-716-230-1009, Electrical Testing of AC Motors, Revision 2
MA-AA-716-230-1009, Electrical Testing of AC Motors, Revision 6
MA-AA-724-104, Meggering of Rotating Electrical Equipment, Revision 0
MA-AA-724-104, Meggering of Rotating Electrical Equipment, Revision 5
MA-AA-724-113, Meggering of Electrical Equipment (Non-Rotating), Revision 7

SC.MD-PM.CH-0001(Q), ACME Chiller Compressor Inspection and Repair, Revision 21
SC.MD-PM.ZZ-0018(Q), AC Motor Cleaning and Inspection, Revision 8
SC.MD-PM.ZZ-0018(Q), AC Motor Cleaning and Inspection, Revision 9
SH.MD-GP.ZZ-0011(Q), Meggering of Rotating Electrical Equipment, Revision 6
WC-AA-106, Work Screening and Processing, Revision 15

Notifications

20361038	20391502	20612085	20660345	20683222	20683783
20684528*	20684553	20684871	20684971	20688776	20688777
20690362*					

Maintenance Orders/Work Orders

30148344	30173815	30206124	30250602	50002207	50033803
60080151	60122639	70072723	70082723	70175042	70176483
70176484					

Other Documents
S-C-F400-MDC-0096, Auxiliary Feedwater Storage Tank Capacity Verification, Revision 4
S-C-VAR-MDC-1429, Minimum Usable Volume for Various Safety Related and Important-to-Safety Tanks, Revision 11
SC-AF002-01, Unit 1 & 2 AFST Level Indication and Alarm, Revision 4
Maintenance Strategy: S1CH-1CHE8-MTRX
ML102000445
PCM Low Voltage Electric Motors
PCM High and Medium Voltage Electric Motors
Salem Unit 1 Narrative Log 03/28/2015, Day Shift, Crew C
Salem Unit 1 Narrative Log 03/29/2015, Day Shift, Crew C

Section 1R19: Post-Maintenance Testing

Procedures
S1.OP-ST.CH-0004, Chilled Water Systems – Chillers, Revision 12
S1.OP-ST.DG-0001, 1A Diesel Generator Surveillance Test, Revision 46

Notifications

20683222	20692420*	20692454*	20692455*

Maintenance Orders/Work Orders

60060902	60122639

Section 1R22: Surveillance Testing

Procedures
CY-AP-120-140, EPRI PWR Primary/Sodium Hydroxide Tanks Chemistry, Revision 4
CY-AP-120-9000, Laboratory Data Review, Revision 1
ER-AA-1001, Component Classification, Revision 2
ER-AP-331-1003, RC Leakage Monitoring and Action Plan, Revision 5
LS-AA-125-1003, Equipment Apparent Cause Evaluation Guide
LS-SA-1000-1001, Salem Generating Station Unit 1 Surveillance Frequency Control Program List of Surveillance Frequencies, Revision 5
MA-AA-716-210, Preventive Maintenance Program, Revision 10

S1.OP-SO.CH-0001, Chilled Water System Operation, Revision 28
S1.OP-SO.RC-0004, Identifying and Measuring Leakage, Revision 14
S1.OP-ST.AF-0001, IST - 11 Auxiliary Feedwater Pump, Revision 16
S1.OP-ST.CH-0002, IST – 12 Chilled Water Pump, Revision 15
S1.OP-TM.ZZ-0002, Tank Capacity Data, Revision 8
S1.RA.ST-AF-0001, IST - 11 Auxiliary Feedwater Pump Acceptance Criteria, Revision 7
S1.OP-DL.ZZ-0003, Control Room Log – Modes 1-4, Revision 76
S1.OP-ST.CS-0001, IST - 11 Containment Spray Pump, Revision 18
S1.OP-ST.CS-0008, Containment Spray System Additive Tank Operability Modes 1-4, Revision 3
S1.OP-ST.RC-0008, Reactor Coolant System Water Inventory Balance, Revision 26
S1.RA-ST.CH-0002, IST - 12 Chilled Water Pump Acceptance Criteria, Revision 9
S2.IC-FT.RCP-0098, Steam Generator Steam Flow and Turbine Steam Line Inlet Pressure Protection Channel I, Revision 30
SC.CH-AD.CS-0415, Adjusting Spray Additive Tank Concentration, Revision 12
SC.CH-CA.ZZ-0336, Sodium Hydroxide by Titration, Revision 5
SC.CH-CA.ZZ-0401, Certification of Reactor Plant and Secondary Plant Bulk Chemicals, Revision 15
SC.CH-SA.ZZ-0213, Miscellaneous System Sampling, Revision 20

Notifications

20065263	20096860	20097114	20106136	20118493	20542205
20619741	20625757	20671169	20672432	20675340	20676370
20676454	20676531	20676533	20681245	20681626	20684860
20686816*	20687265*	20687408*	20687626	20688258*	20688259*
20688319*	20688320*	20688750*	20691372	20693956	20694011
20694197	20694276	20694465	20694468	20694597	20694948
20694949	20694950	20695544	20695790		

Maintenance Orders/Work Orders

50155556	50160202	50164313	50168813	50171115	50171928
50173845	50173919	50173920	60019781	60019802	60120640
60121747	70018898	70024211	70024268	70060854	70174523
80053557					

Drawings

205216, Sheet 1, No. 1 & 2 Units Chilled Water, Revision 64
205235, No. 1 Unit Containment Spray, Revision 48

Section 1EP6: Drill Evaluation

Notifications

20688507* 20693417* 20695634*

Procedures

2-EOP-TRIP-1, Reactor Trip or Safety Injection, Revision 28
2-EOP-TRIP-2, Reactor Trip Response, Revision 28
S2.OP-AB.CC-0001, Component Cooling Abnormality, Revision 14

Other Documents
Simulator Training Scenario S-ESG-1502, Revisions 0 and 1
ML041120174
ML110050376
ML112560428

Section 2RS5: Radiation Monitoring Instrumentation

Procedures
NC.CH-RC.ZZ-2525(Q), Gamma Spectroscopy Analysis Using CAS, Revision 5
NC.CH-RC.ZZ-2575(Q), Gamma System Calibration, Revision 3
NC.EP-EP.ZZ-0306(Q), Emergency Air Sampling, Revision 2
NC.EP-EP-ZZ-0311(Q), Control Point Chemistry Response, Revision 10
S1.CH-AB.CBV-1076(Q), Unit 1 Containment Atmosphere Sampling Under Accident Conditions, Revision 0
S2.CH-AB.CBV-2076(Q), Unit 2 Containment Atmosphere Sampling Under Accident Conditions, Revision 0
SC.CH-AB.RC-1075(Q), Sampling Reactor Coolant and RHR Heat Exchanger Outlet Under Accident Conditions, Revision 2
SC.CH-AB.RC-1080(Q), Reactor Coolant Sample Transfer and Dilution Under Accident Conditions, Revision 2

Other Documents
Calibration Reports (Ge-Li Detector)
Certificate of Calibration (Ge-Li sources)
Instrument Calibration data
Liquid and Gaseous monitor set-point determinations, calibration and functional test data
Plant Vent Flow Transmitter calibration (order)
Process Radiation Monitoring System Health Reports
Salem Offsite Dose Calculation Manual
S-C-ZZ-MEE-1666, Rev. 0, Radiological Exposure Associated with Obtaining and Analyzing Post-Accident Reactor Coolant, Containment Sump and Containment Atmosphere Samples

Section 2RS6: Radioactive Gaseous and Liquid Effluent Treatment

Procedures
CY-AA-130-150, Chemistry Quality Assurance, Revision 0
CY-AA-130-200, Chemistry Quality Control, Revision 9
CY-AA-130-205, Radiochemistry Quality Control, Revision 0
EN-AA-170-1000, Radiological Environmental Monitoring Program (REMP) and Meteorological Program (MET) Implementation, Revision 1
EN-AA-170-1001, REMP Vendor Dosimetry Laboratory QA Program, Revision 1
EN-AA-170-300, Offsite Dose Calculation Manual Revisions, Revision 0
EN-AA-170-4160, Station RGPP Controlled Sample Point Parameters, Revision 0
EN-AA-170-4000, Radiological Ground Water Protection Program Implementation, Revision 0
EN-AA-170-4200, Disposition of Water from Excavation Projects, Revision 0
EN-AA-170-4300, Investigation Process for Evaluation of Anomalous Tritium Data from Onsite Wells, Revision 0
EN-AA-170-500, Metrological Monitoring System Calibration and Maintenance, Revision 1
EN-AA-170-501, Metrological Monitoring Program Administration, Revision 0

S1.OP-SO.WL-0001(Q), Release of Radioactive Liquid Waste from CVCS Monitor Tank, Revision 25
SC.CH-AB.ZZ-1102(Q), Response to Inoperable Technical Specification Effluent Monitor Equipment, Revision 27
SC.CH-TI.ZZ-0143(Q), Radioactive Effluent Liquid Effluent Permits By EMS, Revision 4
SC.CH-TI.ZZ-0145(Q), Radioactive Gaseous Effluents Permits, Revision 7
SC.CH-TI.ZZ-0149(Q), Permitting Ground Water Discharge, Revision 3
SC.CH-TI.ZZ-0180(Q), Sampling Schedule and Chemistry Specifications, Revision 68

Other Documents
10 CFR 50.59 Screenings
2013 and 2014 PSEG Salem Effluent and Environmental Annual Reports
2014 Ground Water Protection Program (RGPP) Report
2014 Inter-Intra Laboratory Results
Laboratory Cross Check data (Inter and Intra)
Land Use Census (2014)
Land Use Survey (August 2014)
LS-AA-126-1001, Radioactive Effluents Control (March 3, 2015) Audit
MES Report, Review of Gaseous Release Points and Dispersion Modeling Assumptions at Salem and Hope Creek Stations
Meteorological Data Inter-comparisons (2014)
NOSA-SLM-14-04, Chemistry, Radwaste, Effluents and Environmental Monitoring (May 29, 2014) Audit
Radioactive Release Analyses (liquid and gaseous discharges)
Salem Offsite Dose Calculation Manual
Technical Document- Evaluation of Component Cooling Resin
Technical Specification/ODCM Controlled Log Sheets (R19C, 2R13A, 1FR1064)

Section 4OA1: Performance Indicator Verification

Procedures
LS-AA-2030, Monthly Data Elements for NRC Unplanned Power Changes per 7000 Critical Hours, Revision 6
TQ-AA-210-3208, Just-In-Time Training (JITT), Revision 3

Notifications
20681675* 20686077* 20686786* 20691826* 20693538*

Section 4OA2: Problem Identification and Resolution

Procedures
ER-AA-1001, Component Classification, Revision 2
LS-AA-120, Issue Identification and Screening Process, Revision 13
LS-AA-125, Corrective Action Program, Revision 18
LS-AA-125-1003, Apparent Cause Evaluation Manual, Revision 14
MA-AA-716-010, Maintenance Planning Process, Revision 18
MA-AA-716-210, Preventive Maintenance (PM) Program, Revision 10
MA-AA-716-210-1005, Predefine Change Processing, Revision 4
MA-AA-716-210-1005, Attachment 3 PCR Standard Text Key, Revision 4
OP-AA-108-115 Operability Determinations & Functionality Assessments, Revision 4
PIA-005, Apparent Cause Evaluation Template, Revision 3

S2.OP-SO.CAV-0001 (Q) Control Area Ventilation Operation, 39
SC.MD-CM.CH-0001, ACME Chiller Compressor Maintenance, Revisions 1 and 2
SC.MD-PM.CH-0001, ACME Chiller Compressor Inspection and Repair, Revisions 20 and 21
SC.MD-IS.4KV-0001(Q), 4KV and 13KV Magne-Blast Circuit Breakers Inspection and Test, Revision 28
SC.OP-ST.CAV-0003 (Q) Control Room Emergency Air Conditioning System Manual Actuation, Revision 2
S1.OP-SO.CH-0001, Chilled Water System Operation, Revision 28
S2.OP-SO.CH-0001, Chilled Water System Operation, Revision 31
SY-AA-101-126, General Requirements/ Responsibility BRE Security Post Duties, Revision 8
WC-AA-111, Predefine Process, Revision 8

Notifications

20498660	20574713	20640006	20641025	20641084	20645763
20646740	20658384	20660308	20660365	20662057	20663183
20663415	20663499	20663743	20664925	20665010	20665497
20665897	20667519	20671015	20672738	20673597	20674864
20675158	20676871	20677028	20677427	20677581	20678063
20679740	20680548	20680655	20680780	20680822	20680833
20681569	20681597	20681605	20681606	20681734	20682564
20682565	20682921	20683080	20683373	20683806	20683810*
20683811*	20683910*	20684638*	20685541*	20685781	20686094
20686521	20687576*	20687727	20687732	20688687*	20690792*
20690793*	20692452*	20692457*	20692646*	20692865*	20692954*
20693396*	20693673*	20693738*	20693994*	20694194*	20695071*

Maintenance Orders/Work Orders

30131174	60119357	60120031	70059902	70149711	70166610
70168409	70168504	70168645	70168725	70169007	70170036
70170475	70170868	70170894	70171684	70171706	960717300

Other Documents
RCE, Increasing Trend in Chiller Failures, 70169007
ACE, 21 Chiller Tripped on Freeze Protection, 70171934
ACE, 22 Chiller Trips on Low Oil Pressure, 70132535
121827, General Electric Vendor Manual 13.8 kV Switchgear, dated 8/1998
317537-01, Magne-Blast Circuit Breaker (4160) Maintenance Procedure, dated 10/1994
EPRI PM Basis Document- PM Program Report, dated 12/2012
Maintenance Strategy: S14KV-1CD1AX5D, 12 SI Injection Pump, dated 4/2015
NP-7410-V2P2, Guidance on Overhaul of Magne-Blast Circuit Breakers, dated 12/2000

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

Other Documents
LER 05000272/2014-005-00, Loss of Safety Function Resulting from Safety Injection Pump Breaker Failure
ILOT 13-01, NOS05CHLWAT, Licensed Operator Systems Training, Chilled Water System
VTD 325458, Chilled Water System Evaporator Vendor Manual, dated 01/17/03

LIST OF ACRONYMS

10 CFR	Title 10 of the *Code of Federal Regulations*
AC	alternating current
ACE	apparent cause evaluation
ADAMS	Agencywide Documents Access and Management System
AFW	auxiliary feedwater
ALARA	as low as is reasonably achievable
ANSI	American National Standards Institute
CA	corrective action
CAP	corrective action program
CAQ	condition adverse to quality
CCW	component cooling water
CFCU	containment fan cooling unit
CFR	Code of Federal Regulation
CREACS	control room emergency air conditioning system
DLA	Dynamic Learning Activity
EAL	Emergency Action Level
EDG	emergency diesel generator
EN	event notification
EPRI	Electric Power Research Institute
FWH	feedwater heater
GE	General Electric
GPI	Groundwater Protection Initiative
HRA	high radiation area
IMC	inspection manual chapter
IN	Information Notice
IR	inspection report
IST	inservice test
kV	kilovolt
LCO	limiting conditions for operations
LER	licensee event report
MR	maintenance rule
MSPI	Mitigating System Performance Index
NCV	non-cited violation
NEI	Nuclear Energy Institute
NEIC	National Earthquake Information Center
NI	nuclear instrumentation
NOS	Nuclear Oversight
NRC	Nuclear Regulatory Commission
OBE	operating basis earthquake
ODCM	Offsite Dose Calculation Manual
PCM	performance centered maintenance
PDP	positive displacement pump
PI	performance indicator
PM	preventive maintenance
PMT	post-maintenance test(ing)
PSEG	Public Service Enterprise Group Nuclear LLC
PU&A	Procedure Use and Adherence
QA	Quality Assurance
RCE	root cause evaluation

RCS	reactor coolant system
REMP	Radiological Environmental Monitoring Program
RG	Regulatory Guide
RGPP	Radiological Ground Water Protection Program
RHR	residual heat removal
RP	radiation protection
RTP	rated thermal power
SDP	significance determination process
SI	safety injection
SR	Surveillance Requirement
SSC	structures, systems, and components
SSE	safe shutdown earthquake
SSFF	safety system functional failure
SW	service water
TS	technical specification(s)
UFSAR	Updated Final Safety Analysis Report
VAC	volts alternating current
VIB	vital instrument bus