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

September 22, 2016

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

SUBJECT: SALEM NUCLEAR GENERATING STATION, UNITS 1 AND 2 – INTEGRATED INSPECTION REPORT 05000272/2016002 AND 05000311/2016002

Dear Mr. Sena:

On June 30, 2016, the U.S. Nuclear Regulatory Commission (NRC) completed an inspection at the Salem Nuclear Generating Station, Units 1 and 2 (Salem). The enclosed inspection report documents the inspection results, which were discussed with Mr. Robert DeNight on July 28, 2016, and with Mr. Eric Carr on August 11, 2016, as well as other members of your staff.

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

The inspectors documented two findings of very low safety significance (Green) in this report. Further, inspectors documented a licensee-identified violation which was determined to be of very low safety significance in this report. The NRC is treating these issues as one finding (FIN) and as two non-cited violations (NCV) consistent with Section 2.3.2.a of the Enforcement Policy.

If you contest the NCV in this report, you should provide a response within 30 days of the date of this inspection report, with the basis for your denial, to the Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington, DC 20555-0001; with copies to the Regional Administrator, Region I; the Director, Office of Enforcement, United States Nuclear Regulatory Commission, Washington, DC 20555-0001; and the NRC Resident Inspector at Salem. 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.

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/

Fred L. Bower, III, 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 05000272/2016002 and
05000311/2016002
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.	05000272/2016002 and 05000311/2016002
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, 2016 through June 30, 2016
Inspectors:	P. Finney, Senior Resident Inspector A. Ziedonis, Resident Inspector E. Burket, Emergency Preparedness Specialist G. DiPaolo, Senior Reactor Inspector M. Draxton, Project Engineer J. Kulp, Senior Reactor Inspector M. Modes, Senior Reactor Inspector R. Nimitz, Senior Health Physicist T. O'Hara, Reactor Engineer D. Orr, Senior Reactor Inspector R. Vadella, Project Engineer J. Poehler, Senior Materials Engineer
Approved By:	Fred L. Bower, III, Chief Reactor Projects Branch 3 Division of Reactor Projects

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SUMMARY

Inspection Report (IR) 05000272/2016002, 05000311/2016002; 04/01/2016 – 06/30/2016; Salem Nuclear Generating Station Units 1 and 2; Operability Determinations and Functionality Assessments; Follow-Up of Events and Notices of Enforcement Discretion.

This report covered a three-month period of inspection by resident inspectors and announced inspections performed by regional inspectors. The inspectors documented one self-revealing finding of very low safety significance (Green), one non-cited violation (NCV), one finding (FIN) and one licensee identified violation. 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 and Initiating Events

- Green. The inspectors identified a Green non-cited violation (NCV) of Title 10 of the *Code of Federal Regulations* (10 CFR) Part 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," because, from June 15, 2016 until July 26, 2016, PSEG did not accomplish actions necessary to provide adequate confidence that a structure, system, and component (SSC) would perform satisfactorily in service (an activity affecting quality) as prescribed by a documented procedure. Specifically, although PSEG had concluded Salem Unit 2 is susceptible to baffle bolt failure due to its design and operating life (but less susceptible than Salem Unit 1), PSEG inadequately implemented Procedure OP-AA-108-115, "Operability Determinations & Functionality Assessments," Sections 4.7.14 followed by Sections 4.7.18-4.7.20 to perform an operability evaluation (OpEval) to justify continued operation of the unit until the next refueling outage. PSEG's immediate corrective actions included entering the issue into its corrective action program (NOTF 20736630) and documenting an operability evaluation to support the basis for functionality of the baffle structure and the operability of the emergency core cooling system (ECCS) and reactivity control systems.

This finding is more than minor because it is associated with the equipment performance attribute of the Mitigating Systems cornerstone and affected the cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences, in that degradation of a significant number of baffle bolts could result in baffle plates dislodging following an accident. This issue was dispositioned as more than minor because it was also similar to example 3.j of IMC 0612, Appendix E, "Examples of Minor Issues," in that the condition resulted in reasonable doubt of operability of the ECCS and additional analysis was necessary to verify operability. 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 screened the finding for safety significance and determined it to be of very low safety significance (Green), since the finding did not represent an actual loss of system or function. After inspector questioning, PSEG performed OpEval 2016-015, which provided sufficient bases to conclude the Unit 2 baffle assembly would support ECCS and control rod system operability until the next refueling outage. This finding is related to the cross-cutting aspect of Operating Experience because PSEG did not effectively evaluate relevant internal and external operating experience. Specifically, PSEG did not adequately evaluate the impact of degraded baffle bolts in Unit 2 when directly relevant operating experience was identified at Unit 1. [P.5] (Section 1R15)

- Green. A Green, self-revealing finding (FIN) was identified against MA-AA-716-010, "Maintenance Planning Process," Revision 18, when PSEG work orders (WOs) did not specify the appropriate procedure to perform satisfactory modification testing of the main generator automatic voltage regulator (AVR) protective relay (model STV1). Consequently, the relay actuated below its design setpoint on February 4, 2016, resulting in an automatic trip of the Unit 2 main turbine and reactor. PSEG entered the issue in their Corrective Action Program (CAP) and performed a root cause evaluation (RCE), replaced the failed STV1 relay with a properly tested relay, verified other STV relays were appropriately tested as an extent of condition, and initiated an action to revise Laboratory Testing Services (LTS) department relay test procedures to ensure all applicable acceptance criteria will be incorporated.

  The inspectors determined that a performance deficiency existed because PSEG WOs did not specify the appropriate procedure to perform satisfactory modification testing of the main generator AVR protection relay. This issue was more than minor since it was associated with the procedure quality attribute of the Initiating Events cornerstone and adversely impacted its objective to limit the likelihood of events that upset plant stability (turbine and reactor trip) and challenge critical safety functions. Using IMC 0609, Attachment 4 and Appendix A, Exhibit 1, the inspectors determined that this finding was of very low safety significance, or Green, since mitigating equipment relied up to transition the plant to stable shutdown remained available. The finding had a cross-cutting aspect in the area of Human Performance, Work Management, in that the PSEG did not adequately implement the work process to coordinate with engineering and maintenance departments as needed to appropriately plan the STV1 relay modification test WO. [H.5] (Section 4OA3.3)

Other Findings

A violation of very low safety significance that was identified by PSEG was reviewed by the inspectors. Corrective actions taken or planned by PSEG have been entered into PSEG's CAP. This violation and corrective actions tracking number are listed in Section 4OA7 of this report.

REPORT DETAILS

Summary of Plant Status

Unit 1 began the inspection period at 100 percent power. The unit was shut down for a refueling outage on April 14.

Unit 2 began the inspection period at 100 percent power. The unit remained at or near 100 percent power until June 28, when the unit tripped due to actuation of the main generator protection system. The unit remained shut down at the end of the inspection period.

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, and Barrier Integrity

1R01 Adverse Weather Protection (71111.01 – 1 sample)

.1 Summer Readiness of Offsite and Alternate Alternating Current Power Systems

a. Inspection Scope

The inspectors reviewed plant features and procedures for the operation and continued availability of the offsite and alternate alternating current (AC) power system to evaluate readiness of the systems prior to seasonal high grid loading on May 31. 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 WOs, and walking down portions of the offsite and AC power systems including the 500 kilovolt (kV).

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, 1A and 1C 125V direct current (DC) system during 1B 125V DC battery inoperability on April 6
- Unit 1, Containment penetrations during irradiated fuel moves on April 19

- Unit 2, Service water (SW) system during 21 SW pump emergent repairs on June 7
- Unit 2, Auxiliary building ventilation with damper 2ABV2 failed open on June 16

The inspectors selected these systems based on their risk-significance relative to the reactor safety cornerstones at the time they were inspected. The inspectors reviewed applicable operating procedures, system diagrams, the Updated Final Safety Analysis Report (UFSAR), technical specification(s) (TSs), WOs, notifications (NOTFs), and the impact of ongoing work activities on redundant trains of equipment in order to identify conditions that could have impacted the system's performance of its 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 June 22, 2016, the inspectors performed a complete system walkdown of accessible portions of the Unit 2 safety injection (SI) 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, component lubrication and equipment cooling, hanger and support functionality, and operability of support systems. The inspectors performed field walkdowns of accessible portions of the systems to verify as-built system configuration matched plant documentation, and that system components and support equipment remained operable. The inspectors confirmed that systems and components were aligned correctly, free from interference from temporary services or isolation boundaries, environmentally qualified, and protected from external threats. The inspectors also examined the material condition of the components for degradation and observed operating parameters of equipment to verify that there were no deficiencies. Additionally, the inspectors reviewed a sample of related notifications and WOs to ensure PSEG appropriately evaluated and resolved any deficiencies.

b. Findings

No findings were identified.

1R05 Fire Protection

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

a. Inspection Scope

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

- Unit 2, Spent fuel (SF) and component cooling heat exchangers (HXs) on May 12
- Unit 2, Boric acid evaporator unit and chemistry area on May 20
- Unit 2, SW pump bays during 21 SW pump maintenance on June 8
- Unit 2, 2B and 2C emergency diesel generator (EDG) rooms on June 16
- Unit 2, Chiller room while protected on June 16

b. Findings

No findings were identified.

1R07 Heat Sink Performance (711111.07A – 1 sample)

a. Inspection Scope

The inspectors reviewed the 12 SI pump lube oil cooler readiness and availability to perform its safety functions. The inspectors reviewed the design basis for the component and verified PSEGs commitments to NRC Generic Letter 89-13, “Service Water Requirements Affecting Safety-Related Equipment.” The inspectors performed inspection of the as-found conditions, and discussed the results of previous inspections with PSEG staff. The inspectors verified that PSEG initiated appropriate corrective actions for identified deficiencies. The inspectors also verified that the number of tubes plugged within the HX did not exceed the maximum amount allowed.

b. Findings

No findings were identified.

1R08 In-service Inspection Activities (71111.08 – 1 sample)

a. Inspection Scope

Inspectors from the NRC Region I Office, specializing in materials and in-service examination activities, observed portions of PSEG’s activities involving baffle bolt examinations and replacements during the Salem Unit 1 spring 2016 refueling outage (1R24). PSEG notified the NRC of problems with baffle bolts in Event

Notification 51902, "Anomalies Identified during Visual Inspection of Reactor Vessel Internals." During May 17-19, 2016, and June 20-23, 2016, inspectors conducted an inspection of PSEG's evaluation of the baffle bolt ultrasonic testing results and visual examination performed during 1R24. The inspectors reviewed documentation, interviewed personnel, and reviewed video recordings of visual examinations performed during the current and previous refueling outages. The inspectors also observed in-progress baffle bolt replacement activities.

Nondestructive Examination and Welding Activities (Section 02.01)

The inspectors conducted a review of PSEG's implementation of in-service inspection (ISI) program activities for monitoring degradation of the reactor coolant system boundary, risk significant piping and components, and containment systems during Salem Unit 1 refueling outage 1R24. The sample selection was based on the inspection procedure objectives and risk priority of those pressure retaining components in these systems where degradation would result in a significant increase in risk. The inspectors observed in-process nondestructive examination (NDE), reviewed records, and interviewed personnel to verify the following: a) that non-destructive activities were performed in accordance with American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code Section XI, 2004 Edition, no Addenda, requirements; b) that indications and defects, if present, were dispositioned in accordance with the ASME Code or an NRC approved alternative; and, c) that relevant indications were compared to previous examinations to determine if any changes occurred.

The inspectors reviewed the ultrasonic testing (UT) procedure used for the examination of the Unit 1 baffle bolts to verify it met the requirements of the ASME Boiler and Pressure Vessel Code and the applicable guidance in the Electric Power Research Institute's Materials Reliability Program (MRP-227 and 228). The inspectors reviewed the UT data records for the examinations performed during the 1R24 refueling outage to verify that activities were performed in accordance with applicable examination procedures.

The inspectors reviewed video from the visual examination of the baffle bolts performed in the current refueling outage (RFO). The inspectors also reviewed video of visual examinations performed during Unit 1 RFOs in 2001, 2013, and 2014 to assess the as-found conditions of the baffle bolts. The inspectors reviewed certifications of the NDE technicians performing the examinations to verify the examinations were performed by qualified individuals in accordance with approved procedures and the results reviewed and evaluated by certified Level III NDE personnel.

The inspectors performed a sample of observations of NDE activities and reviewed records of NDE activities. The review sample consisted of two or three types of NDE activities, including at least one volumetric examination.

ASME Code Required Examinations

Salem Unit 1, Liquid Penetrant Report No. PT-16-002, 11-RHRHEX Vessel Support, 4/15/16, (Summary No.205170) [record review]

Salem Unit 1, Liquid Penetrant Report No. PT-16-001, Pipe Lugs 8-RH-2116-10PL-1 through 4, 4/15/16, (Summary No. 263631) [record review]

Salem Unit 1, Liquid Penetrant Report No. PT-16-004, Pipe to Penetration IA, Component 12 SJ-2152-36PS-4, 4/19/16, (Summary No. 263904) [record review]
Salem Unit 1, Liquid Penetrant Report No. PT-16-003, Inlet Nozzle To 11 Charging Pump, Component 6-CV-2111-14R1, 4/15/16, (Summary No. 220757) [record review]
Salem Unit 1, Liquid Penetrant Report No. PT-16-005, Pipe-to-Valve (11CS48) [record review] Component ID: 8-CS-2114-60, 4/15/16, (Summary No. 56640)
Salem Unit 1, Ultrasonic examination (Summary #006325) Report UT-16-039, Component ID: 1-PZR-20, Pressurizer, shell J weld [Observed]
Component ID: 16-BFN-2111-IRS, Inside Radius Section Ultrasonic Examination, 16-BF-2111, Report UT-16-013, Steam Generator #11, (Summary #204201) [Observed]
Component 4-PRN-1100-IRS, Pressurizer Relief Nozzle, inside Radius Section, Ultrasonic Examination, (Summary #007000), UT-16-031, [Observed]

Observation of Baffle Bolt Replacement Activities

The inspectors observed electrical discharge machining activities on a baffle bolt location. The inspectors observed the bolt hole milling activities for a baffle bolt. The inspectors verified that bolt replacement activities were being performed in accordance with approved procedures.

Other Augmented, License Renewal or Industry Initiative Examinations

PSEG did not schedule augmented inspections in the outage scope for 1R24.

Review of Relevant Indication(s) Evaluated and Accepted for Continued Service

PSEG did not have any originally rejectable indications since the end of their prior outage, which were later accepted for continued use after evaluation.

Modifications, Repairs, or Replacements Consisting of Welding on Pressure Boundary Risk Significant Systems

The inspectors reviewed Design Change Package 80092579, Salem Unit 1 – Steam Generator (SG) Bowl Drain Repair, for SGs 11, 12, 13, and 14. This change removed Alloy 600 and associated 82/182 weld material from each SG channel head bowl drain plug to reduce the potential for primary water stress corrosion cracking. The inspectors determined overall whether the modifications were completed in accordance with ASME Section XI as a repair/replacement activity. Specifically, the inspectors reviewed the machining and welding procedures used to complete the modifications, reviewed the training of the machinists, welders and laborers qualified on a mockup of the channel heads, and reviewed the mockup training completed by all craft personnel on the project. The inspectors reviewed the in-process NDE and the final NDE procedures to determine whether the change was implemented in accordance with ASME Section XI repair/replacement requirements.

PWR Vessel Upper Head Penetration Inspection Activities (Section 02.02)

The Salem Unit 1 reactor pressure vessel head was replaced with an Alloy 690 head in 2005. The inspectors determined that reactor pressure vessel head examinations (per ASME Code Case N-729) were not required during 1R24.

Boric Acid Corrosion Control Inspection Activities (Section 02.03)

The inspectors reviewed the Boric Acid Corrosion Control program and implementing PSEG procedures, and discussed the outage inspections with program engineers. The inspectors also reviewed documentation, corrective action process notifications, including photographic records, of the conditions identified during the plant shutdown. The inspectors also reviewed a sample of notifications recommending repairs to identified conditions and a sample of boric acid engineering evaluations performed to determine the priority of repair of identified boric acid corrosion on safety significant piping and components. Boric acid inspections were conducted on safety significant piping and components inside the containment structure during walk downs conducted by PSEG staff with the plant at normal pressure and temperature conditions. The inspectors reviewed a sample of photos and visual inspection records to verify that boric acid leakage was being appropriately identified and non-conforming conditions of boric acid leaks were documented in the CAP with a focus on areas that could cause degradation of safety significant components.

The inspectors verified that potentially more significant boric acid deficiencies were being adequately dispositioned by reviewing a sample of evaluations documented in the following PSEG condition reports: 20682192, 20699859, 20699820, 20699910, 20704139, 20707125, 20712774, 20713572, 20722494, 20682192, 20699859, 20707125, 20722494, 70179375, 20699820, 20704139, 70185980, 20712774, 20713573, 20713572.

These reviews verified whether the corrective actions were consistent with the requirements of the ASME Code and 10 CFR Part 50, Appendix B, Criterion XVI. The inspectors reviewed the engineering evaluations associated with these condition reports to verify whether equipment or components wetted or impinged upon by boric acid solutions were properly analyzed for degradation that might impact their function.

Steam Generator Tube Inspection Activities (Section 02.04)

PSEG's Base Eddy Current Test (ECT) program consisted of: (a) 100 percent bobbin probe inspection of straight and U-bend tubes, (b) 50 percent Hot Leg coverage of Top of Tubesheet area with an array probe, (c) 3 tube periphery tube array testing, and various + Point sampling strategies (for U-bend and Dent/Ding inspections) of in-service tubes were completed in each SG. The inspectors reviewed the 1R24 SG tube Degradation Assessment, ECT examination scope and expansion criteria to verify that it met TS requirements, Electric Power Research Institute (EPRI) guidelines, and commitments made to the NRC. The inspectors also verified that the ECT scope included areas of degradation that were known to represent potential ECT challenges such as the top of tube sheet, tube support plates, and U-bends. Upon completion of eddy current (EC) examinations and the evaluation of all data, PSEG staff determined that six tubes required plugging. The affected tubes were plugged during 1R24. The inspectors verified that the affected tubes were properly screened against the in situ screening criteria and that none of the tube indications required in-situ pressure testing.

The inspectors observed portions of the ECT being performed and verified whether: (1) the appropriate probes were used for identifying the expected types of degradation, (2) calibration requirements were adhered to, and (3) probe travel speed was in accordance with procedural requirements. The inspectors performed a review of the site-specific qualifications for the techniques being used, and verified whether the ECT data analyses were adequately performed per EPRI and PSEG specific guidelines. The inspectors selected a sample of degraded tubes and compared them to the previous outage operational assessment to assess PSEGs prediction capabilities. The inspectors also reviewed a sample of EC data, and verified, through discussion with the data analyst that the analytical techniques used to evaluate the inspection data were adequate. The inspectors further verified that the assumed NDE flaw sizing accuracy was consistent with data from EPRI examination technique specification sheet or applicable performance demonstration. Finally, the inspectors reviewed the qualifications for the EC data collection personnel, a sample of the inspection supervision personnel qualifications and a sample of the qualifications of staff responsible for interpretation and resolution analysis to determine whether the records were complete.

The inspectors observed a portion of a plug integrity visual examination per procedure 81DP-9RC40, “Steam Generator Channel Head Video Inspection,” to verify that those tubes that had been previously plugged did not exhibit any leakage. No evidence of plug leakage was identified. Additionally, the inspectors observed a portion of the secondary sludge lancing and foreign object search and retrieval (FOSAR) inspections. No significant foreign materials or quantity of sludge were identified.

During the prior operating cycle previous to the current refueling outage 1R24, the inspectors determined whether leakage from each SG was measured, via sampling of each SG, for the complete prior operating cycle (leakage was not measured).

PSEG staff completed secondary side inspections and sludge lancing of all SG’s. The inspectors reviewed the results to determine that no loose parts affecting tube integrity were noted and that other SG related inspections were performed without repairs. PSEG staff performed a plug integrity visual examination to verify that those tubes that had been previously plugged did not exhibit leakage. From this visual exam, PSEG staff documented excessive boron buildup around tube plug 43-34 in the SG 11 cold leg and initiated CR-2016-29172 to track the evaluation of the condition. PSEG staff also initiated Notification 20726743 to track the condition. PSEG Engineering staff review of the plug concluded that no evidence of plug leakage had occurred. Additionally, secondary sludge lancing and FOSAR inspections were performed in each SG. No foreign materials, which could damage SG tubes, were identified. The inspectors reviewed the PSEG evaluations and information to determine the conclusions were technically supported.

Identification and Resolution of Problems (Section 02.05)

The inspectors reviewed a sample of condition reports, which identified NDE indications, deficiencies and other nonconforming conditions since the previous, 1R23, refueling outage. The inspectors verified that nonconforming conditions were properly identified, characterized, evaluated, corrective actions identified and dispositioned, and appropriately entered into the CAP.

b. Findings

Introduction. The inspectors determined the level of degradation of Unit 1 baffle bolts reported to the NRC as a condition not previously analyzed is an issue of concern that warrants additional inspection to determine whether a performance deficiency exists. As a result, the NRC opened a unresolved item (URI).

Description. Additional inspection is warranted to determine whether a performance deficiency exists related to Event Notification 51902, dated May 3, 2016, in which PSEG reported to the NRC that the level of degradation of baffle bolts was a condition not previously analyzed. The baffle bolts secure plates in the reactor core barrel to form a shroud around the fuel core to direct reactor coolant flow upward through the fuel assemblies. In order to determine if a performance deficiency exists, the inspectors will review the results of PSEG's RCE which will be completed at a later date.
(URI 05000272/2016002-01, Baffle-Former Bolts with Identified Anomalies)

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

Quarterly Review of Licensed Operator Requalification Testing and Training

a. Inspection Scope

The inspectors observed licensed operator simulator training on June 8, 2016, which included a heater drain pump oil leak, a steam generator feed pump trip, and a steam generator tube rupture. 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.

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 SSC performance and reliability. The inspectors reviewed system health reports, CAP documents, maintenance WOs, 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 2, 22SW535, unsatisfactory stroke time of SW accumulator supply valve to 22 containment fan cooler unit (CFCU) on May 2
- Unit 2, Circulating water system 125V DC battery degradation on May 23
- Common, MR URI, 05000272;311/2015008-01: Inadequate MR System Performance Criteria Selection, closeout on May 1

b. Findings

No findings were identified. Additional inspection results regarding the URI closeout are documented in Section 4OA5.

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, 11SW223, SW outlet valve to 11 CFCU, failure to close on April 7
- Unit 1, Reactor core baffle-to-former bolt expanded inspection scope on April 22
- Unit 2, Appendix R safe shutdown panel failed indication on May 9
- Unit 2, 2A subcooling margin monitor failure on May 26
- Unit 2, Yellow risk with one offsite power source unavailable on June 1

b. Findings

No findings were identified.

1R15 Operability Determinations and Functionality Assessments (71111.15 – 9 samples)

a. Inspection Scope

The inspectors reviewed operability determinations for the following degraded or non-conforming conditions based on the risk significance of the associated components and systems:

- Unit 1, Corrosion and metal loss identified during inspection of 11 SW header on April 23
- Unit 1, Immediate operability determination (IOD) of the degraded condition of the baffle-former bolts on April 27
- Unit 1, 1 Emergency control air compressor shutdown on April 27
- Unit 1, SI thermal relief valve failures on May 2
- Unit 1, 13 turbine-driven auxiliary feedwater (AFW) pump degraded performance on May 8
- Unit 1, 11 diesel fuel oil storage tank high particulates on May 18
- Unit 2, IOD of the degraded condition of the baffle-former bolts identified from Unit 1
- operating experience on April 27
- Unit 2, 125V DC battery degraded cell post connections on May 2
- Common, 10 CFR Part 21 issue related to safety-related 4kV breakers on May 16

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. The inspectors confirmed, where appropriate, compliance with bounding limitations associated with the evaluations. 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.

b. Findings

Introduction. The inspectors identified a Green NCV of 10 CFR Part 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," because, from June 15, 2016 until July 26, 2016, PSEG did not accomplish actions necessary to provide adequate confidence that an SSC would perform satisfactorily in service (an activity affecting quality) as prescribed by a documented procedure. Specifically, although PSEG had concluded Salem Unit 2 is susceptible to baffle bolt failure due to its design and operating life (but less susceptible than Salem Unit 1), PSEG inadequately implemented Procedure OP-AA-108-115, "Operability Determinations & Functionality Assessments," by not performing Section 4.7.14 followed by Sections 4.7.18-4.7.20 to perform an operability evaluation (OpEval) to justify continued operation of the unit until the next refueling outage. In particular, PSEG incorrectly exited their procedure on June 15, 2016, and re-entered it to complete these steps on July 26, 2016, based on discussions with the NRC. The operability evaluation provided appropriate justification for the licensee's plans to examine the baffle-former bolts at the next Unit 2 RFO.

Description. On April 22, 2016, PSEG identified baffle-former (“baffle”) bolt degradation at Salem Unit 1 that was determined to be unanalyzed because it did not meet the minimum acceptable bolt pattern analysis developed to support plant startup. PSEG staff identified that 192 baffle bolts out of a total population of 832 were considered degraded. On May 4, 2016, due to the number of degraded baffle bolts discovered on Unit 1, PSEG staff determined that it was necessary to perform an extent of condition review for the baffle bolts on Unit 2. PSEG entered this issue into the corrective action program as NOTF 20727590 and completed an immediate operability determination (IOD) to evaluate the Unit 2 baffle bolts and baffle assembly structure in accordance with PSEG procedure OP-AA-108-115, "Operability Determinations & Functionality Assessments," Section 4.7.4.

The inspectors reviewed the design basis and current licensing basis documents for Unit 2 to identify the specific safety functions of the baffle bolts. The inspectors identified that the baffle bolts are part of the baffle assembly structure located in the reactor pressure vessel. The bolts secure a series of vertical metal plates called baffle plates, which help direct water up through the nuclear fuel assemblies to ensure proper cooling of the fuel. A sufficient number of baffle bolts are required to secure the plates to ensure proper core flow during normal and postulated accident conditions, and also to ensure that control rods can be inserted to shut down the reactor.

On June 21, 2016, the inspectors reviewed the IOD as part of a detailed review of the ongoing baffle bolt activities at Salem and noted that the IOD concluded that there was reasonable assurance that the Unit 2 reactor assembly was operable, but required additional evaluation due to the conditions observed in Unit 1. Specifically, the IOD concluded that there was reasonable assurance that the Unit 2 reactor assembly was operable pending further evaluation based upon the following factors: (1) Unit 2 had fewer effective full power years of operation than Unit 1; (2) a baffle bolt visual examination completed during the most recent Unit 2 2R21 refueling outage (fall 2015) did not identify any visual deficiencies; and, (3) there was no current indication of reactor fuel pin leakage in Unit 2, which could be caused by baffle bolt failure and subsequent fretting. The inspectors’ review of PSEG’s IOD concluded that the IOD provided sufficient technical detail to support the initial conclusion that there was reasonable assurance, based on the limited information available, that the Unit 2 baffle bolts would retain sufficient capability to perform their intended functions. PSEG procedure OP-AA-108-115, Section 4.7.11 directs that “if there is a reasonable expectation that the SSC is operable, but a more rigorous evaluation is deemed warranted, then update the current notification or initiate a notification for Engineering to prepare a Technical Evaluation to support the prompt determination of operability.” The immediate actions section of NOTF 20727590 requested a work order be generated to perform an extent of condition review for Unit 2 baffle bolts. The Station Ownership Committee (SOC) screening of NOTF 20727590 on May 6, 2016, assigned a work order to Engineering “to ensure that Operations is provided the Technical Evaluation product. This will allow review for assessment of operability as required.” From review of the daily running log of baffle bolt action items spreadsheet, the inspectors noted that on May 4, 2016, action EOC.2 to “perform an operability evaluation for Unit 2” was closed to EOC.7-9, to complete an adverse condition monitoring plan, an operational decision making document, and a Technical Evaluation in lieu of an OpEval. Consistent with this decision, on May 26, 2016, the Salem plant manager discussed with the senior resident inspector PSEG’s views that an operability evaluation was not required or being developed. In response, the inspectors shared their understanding of PSEG procedure guidance and regulatory requirements in this regard.

Between May 6 and June 15, 2016, PSEG engineering performed Technical Evaluation 70187161, “Extent of Condition Review for Salem Unit 2 Susceptibility to Baffle Bolt Failure.” The purpose of the Technical Evaluation was to determine the potential for baffle bolt degradation in Unit 2 based upon the results of visual and ultrasonic examination results observed in Unit 1, and to identify and evaluate key factors that could potentially impact the safe operation of Unit 2 for the remainder of the current operating cycle. The Technical Evaluation evaluated the key factors that affect irradiation assisted stress corrosion cracking (IASCC). Additionally, the Technical Evaluation assessed the safety consequences of the degraded baffle bolts in the as-found condition in Unit 1. The Technical Evaluation conclusion summary indicated that Unit 2 is susceptible to baffle bolt failure due to its design and operating life; that any degradation in Unit 2 would be less advanced that that observed in Unit 1; and that PSEG should exercise heightened awareness and monitoring of Unit 2 due to this vulnerability. The Technical Evaluation also concluded that Unit 1 could have safely shut down and the core would be cooled by demonstrating that control rod insertability is assured and a core coolable geometry was maintained. Thus the Technical Evaluation concluded that Unit 2 could also be shut down and cooled based upon the conclusion reached regarding Unit 1. Following completion of the Technical Evaluation on June 15, PSEG did not continue on in the operability determination process.

The inspectors assessed PSEG’s Technical Evaluation 70187161 during an onsite inspection which took place from June 21-23, 2016. PSEG concluded in Technical Evaluation 70187161, that Salem Unit 2 is susceptible to baffle bolt failure due to its design and operating history, but less so than observed in Salem Unit 1. The inspectors determined this conclusion met PSEG’s definition of a “degraded condition” as defined in procedure OP-AA-115-108, Section 2.4. Section 2.4 defines a degraded condition as “A condition in which the qualification of an SSC or its functional capability is reduced.” Section 2.4 lists “reduced reliability” as an example of a degraded condition and “aging” as an example of a condition that can reduce the capability of a system. The inspectors noted that IASCC is a time dependent aging degradation mechanism and baffle bolt failures reduce the functional capability and reliability of the baffle assembly. Consequently the Technical Evaluation describes a degraded condition in the Unit 2 baffle assembly. Since the Technical Evaluation concluded that the reactor could be shut down and cooled based upon the assessment of safety consequences, the inspectors concluded that PSEG considered that the reactivity control and emergency core cooling systems were operable. As a result, the inspectors concluded that PSEG should have continued on in the operability determination process as described in Section 4.7.14, “Operable but Degraded or Nonconforming,” and declared both the reactivity control and emergency core cooling systems “operable but degraded.” Once a SSC is determined to be “operable but degraded,” Section 4.7.18 directs that “An OpEval will be requested based on a declaration of operable but degraded or nonconforming.” Section 4.7.19 directs Engineering to “Prepare and review and OpEval.” Section 4.7.20 directs Operations to approve or disapprove the OpEval when Engineering completes it. Sections 4.7.14, 4.7.18, 4.7.19 and 4.7.20 were not implemented by PSEG.

The inspectors acknowledged that licensees apply judgment in these decisions and can use a graded approach regarding the level of detail. In this particular instance, the inspectors considered that operating experience was available that showed the Unit 2 baffle bolts were subject to IASCC and that plants of similar design (4-loop Westinghouse pressurized water reactors with a down-flow configuration and baffle bolts of 347 stainless steel material and similar dimensions) were subject to greater amounts of bolt degradation compared to other reactor designs. Furthermore, the inspectors noted the baffle bolts had experienced levels of neutron radiation exposure above the threshold for IASCC initiation as referenced in NUREG/CR-7027, "Degradation of LWR Core Internal Materials due to Neutron Irradiation."

The inspectors conducted an exit meeting on June 23, 2016, describing a potential violation of 10 CFR Part 50 Appendix B, Criterion 5, "Instructions, Procedures, and Drawings," for PSEG not completing the OpEval and assessing the effect of the operability of the ECCS and rod control system based upon the functionality of the baffle former assembly. Consistent with the change made by PSEG staff to the Salem action item list on May 4, 2016, to not perform an OpEval, the PSEG Compliance Director indicated that an operability evaluation was not required and therefore they disagreed with this finding.

The inspectors determined that Engineering did not perform an OpEval as directed by OP-AA-108-115 Section 4.7.19, which states "PREPARE and REVIEW an OpEval. The OpEval Form (Attachment 1), or a facsimile, may be used to document the engineering evaluation (Engineering)." Because an OpEval was not prepared, Operations did not have the opportunity to approve or disapprove an OpEval as required by OP-AA-108.115, Section 4.7.20 which states: "When Engineering completes the OpEval, then APPROVE or DISAPPROVE."

In summary, Technical Evaluation 70187161 concluded Unit 2 is susceptible to IASCC baffle bolt degradation and that the expected degradation should be less than that observed in Unit 1. The inspectors assessed that PSEG's conclusions concerning the susceptibility and expected degradation in Unit 2 was adequately supported. However, the inspectors concluded that the Technical Evaluation did not provide adequate confidence that SSCs (baffle bolts supporting ECCS) would perform satisfactorily in service to justify continued operation of Unit 2 until the next refueling outage in the spring of 2017 in that line break size assumptions were not adequately supported.

Following discussions with NRC Region I management and the inspectors, PSEG staff subsequently completed an operability evaluation (OpEval 2016-015) on July 26, 2016. The OpEval compared the differences in the operating history and parameters between Unit 1 and Unit 2 and again concluded that Unit 2 was less susceptible than Unit 1 primarily due to significantly fewer thermal cycles and fewer effective full power years (EFPY) of operation. The OpEval concluded that operability was supported although "the Unit 2 baffle assemblies are considered degraded since Unit 2 is susceptible to degraded baffle bolts." Based upon a qualitative analysis, PSEG's OpEval stated that Unit 2 can accommodate 38 percent degraded baffled-former bolts (distributed across the assembly) and remain within the acceptable bolting pattern analysis patterns assuming the dynamic loads of a large break loss of coolant accident. The inspectors concluded that PSEG's OpEval 2016-015 provided an adequate basis to conclude that the Unit 2 baffle assembly would support ECCS and rod control system continued operation until the planned refueling outage in spring 2017. In particular, the inspectors considered that PSEG's visual examinations of approximately 70 percent of the baffle bolts, in the fall 2015 refueling outage (2R21), did not identify any bolts that were missing or visually degraded. Considering the collective results from Salem Unit 1 and 2 baffle bolt visual examination results, the inspectors determined this evidence, in conjunction with a review of other operating factors (EFPY and thermal cycles), provided a reasonable expectation of the Salem Unit 2 baffle assembly's capability to perform its supporting TS functions.

Analysis. The inspectors determined that a performance deficiency resulted when PSEG did not implement Procedure OP-AA-108-115, "Operability Determinations & Functionality Assessments," Section 4.7.14 followed by Sections 4.7.18-4.7.20 to perform an OpEval to justify continued operation of the unit until the next refueling outage for the Unit 2 baffle bolt degraded condition until questioned by NRC inspectors. PSEG's initial documentation did not provide sufficient basis for continued operation until the next refueling outage. Specifically, based upon the Technical Evaluation 70187161 conclusion that the Salem Unit 2 design and operating life make it susceptible to baffle bolt failures, the inspectors determined that PSEG, in effect, concluded that a degraded condition exists in Unit 2. Therefore, PSEG should have continued on in the operability determination process as described in Section 4.7.14, "Operable but Degraded or Nonconforming."

This finding is more than minor because it is associated with the equipment performance attribute of the Mitigating Systems cornerstone and affected the cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences, in that, degradation of a significant number of baffle bolts could result in baffle plates dislodging following an accident. This issue was dispositioned as more than minor because it was also similar to example 3.j of IMC 0612, Appendix E, "Examples of Minor Issues," in that, the condition resulted in reasonable doubt of operability of the ECCS and additional analysis was necessary to verify operability. 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 screened the finding for safety significance and determined it to be of very low safety significance (Green), since the finding did not represent an actual loss of system or function. After inspector questioning, PSEG performed OpEval 2016-015, which provided sufficient bases to conclude the Unit 2 baffle assembly would support ECCS and control rod system operability until the next RFO. This finding is related to the cross-cutting aspect of Operating Experience because PSEG did not effectively evaluate relevant internal and external operating experience. Specifically, PSEG did not adequately evaluate the impact of degraded baffle bolts at Unit 2 when directly relevant operating experience was identified at Unit 1. [P.5]

Enforcement. 10 CFR Part 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," states, in part, that activities affecting quality shall be prescribed by documented procedures of a type appropriate to the circumstances and shall be accomplished in accordance with those procedures. The *Introduction* to Appendix B states that 'quality assurance' comprises all those planned and systematic actions necessary to provide adequate confidence that a SSC will perform satisfactorily in service. PSEG Procedure OP-AA-108-115, "Operability Determinations & Functionality Assessments," prescribes PSEG's process to assess the operability of SSCs that are required to be operable by TSs, or that perform required support functions for SSCs that are required to be operable by TSs. Section 4.7 prescribes the operability determination process. Section 4.7.14 states that if an SSC described in TSs is determined to be operable even though a degraded or nonconforming condition is present, then the SSC is considered “operable but degraded or nonconforming.” Sections 4.7.18 - 4.7.20 describe how the Operations Shift Manager should request the site engineering staff to perform an “OpEval” upon a declaration of operable but degraded, or nonconforming. The OpEval is completed to justify continued operation during the period of time while operable but degraded or nonconforming conditions exist.

Contrary to the above, from June 15, 2016, until July 26, 2016, PSEG did not accomplish actions necessary to provide adequate confidence that an SSC would perform satisfactorily in service (an activity affecting quality) as prescribed by a documented procedure. Specifically, although PSEG had concluded the Salem Unit 2 design and operating life make it susceptible to baffle former bolt failures, PSEG inadequately implemented Procedure OP-AA-108-115, to perform an OpEval to justify continued operation of the unit. PSEG’s corrective actions included entering the issue into its corrective action program (NOTF 20736630) and documenting an adequate operability evaluation (OpEval 2016-015 on July 26, 2016) to support the basis for functionality of the baffle structure and its ability to support the operability of the ECCS and reactivity control systems. This violation is being treated as an NCV, consistent with Section 2.3.2 of the Enforcement Policy. **(NCV 05000311/2016002-02, Failure to Follow Operability Determination Procedure for Unit 2 Baffle-Former Bolts)**

1R18 Plant Modifications (71111.18 – 2 samples)

.2 Permanent Modifications

a. Inspection Scope

The inspectors reviewed Design Change Package (DCP) 80117136, “Salem Unit 1 Baffle to Former Bolt Replacement.’’ This modification documents the replacement of 189 degraded and potentially degraded baffle bolts with a new design baffle bolt made of an improved material. Additionally the modification documented the locations of the replacement bolts and the location of three degraded or potentially degraded bolts which were left in place and are described below. The inspectors also reviewed modification documents (DCP 80117378) associated with the equivalency evaluation of the material change from Type 347 stainless steel to Type 316 stainless steel, and the bolt head design change from a slot to a hex configuration. Thus this inspection involved two samples – 1) the bolting pattern analysis for the replacement bolts, and 2) a review of the bolting material change.

This modification was completed during the spring 2016 refueling outage (1R24) and involved the replacement of 189 baffle bolts out of a total of 832 located in the Unit 1 reactor vessel. PSEG replaced 189 either degraded or potentially degraded baffle bolts as observed by visual indications of missing or protruding bolt heads, missing or broken lock bar, bolts that did not pass ultrasonic testing or bolts that were inaccessible for ultrasonic testing. PSEG did not remove and replace three bolts that were potentially degraded due to difficulties encountered during the removal/replacement process. One bolt had an indication during ultrasonic testing but was not visibly damaged. The second bolt was inaccessible for ultrasonic testing, which would have required replacement. The third bolt had successfully passed an ultrasonic test but had a visual indication on one of the lock bar welds which may have indicated a crack in the weld.

The inspectors reviewed PSEGs analysis and the Westinghouse minimum bolting analysis and determined that leaving the one degraded and two potentially degraded bolts installed was technically acceptable and that the baffle assembly was functional as a system support component. Details of the NRC assessment of the final configuration of the baffle bolts and the minimum bolting analysis can be found in Section 4OA2 of this report.

b. Findings

No findings were identified.

1R19 Post-Maintenance Testing (71111.19 – 9 samples)

a. Inspection Scope

The inspectors reviewed the post-maintenance tests for the maintenance activities listed below to verify that procedures and test activities adequately tested the safety functions that may have been affected by the maintenance activity, that the acceptance criteria in the procedure were consistent with the information in the applicable licensing basis and/or design basis documents, and that the test results were properly reviewed and accepted and problems were appropriately documented. The inspectors also walked down the affected job site, observed the pre-job brief and post-job critique where possible, confirmed work site cleanliness was maintained, and witnessed the test or reviewed test data to verify quality control hold point were performed and checked, and that results adequately demonstrated restoration of the affected safety functions.

- Unit 1, 13 Station power transformer tap changer did not function in automatic on May 4
  - Unit 1 11SJ45, residual heat removal (RHR) to SI motor-operated valve failure to stroke closed on May 5
- Unit 1, 12 containment fan cooling unit (CFCU) motor cooler HX failed leak test on May 6
- Unit 1, Reactor coolant pump flow channel III degraded on May 6
- Unit 1, Turbine-driven AFW room cooler cycling on May 10
- Unit 1, Reactor vessel level indication system capillary repair on May 13
- Unit 2, 24 SW strainer trip on thermal overloads on April 7
- Unit 2, 24 SG flow channel 1 drop to 93 percent on May 4
- Unit 2, 21 Chiller thermal expansion valve failure on May 24

b. Findings

No findings were identified.

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

a. Inspection Scope

The inspectors reviewed the station's work schedule and outage risk plan for the Unit 1 maintenance and refueling outage (1R24), conducted April 14 through the end of the quarter. The inspectors reviewed PSEGs development and implementation of outage plans and schedules to verify that risk, industry experience, previous site-specific problems, and defense-in-depth were considered. During the outage, the inspectors observed portions of the shutdown and cooldown processes and monitored controls associated with the following outage activities:

- Configuration management, including maintenance of defense-in-depth, commensurate with the outage plan for the key safety functions and compliance with the applicable TSs when taking equipment out of service
- Implementation of clearance activities and confirmation that tags were properly hung and that equipment was appropriately configured to safely support the associated work or testing
- Installation and configuration of reactor coolant pressure, level, and temperature instruments to provide accurate indication and instrument error accounting
- Status and configuration of electrical systems and switchyard activities to ensure that TSs were met
- Monitoring of decay heat removal operations
- Impact of outage work on the ability of the operators to operate the SF pool cooling system
- Reactor water inventory controls, including flow paths, configurations, alternative means for inventory additions, and controls to prevent inventory loss
- Activities that could affect reactivity
- Maintenance of secondary containment as required by TSs
- Refueling activities, including fuel handling and fuel receipt inspections
- Fatigue management
- Tracking of startup prerequisites, walkdown of the drywell (primary containment) to verify that debris had not been left which could block the emergency core cooling system suction strainers, and startup and ascension to full power operation
- Identification and resolution of problems related to refueling outage activities
- Foreign Object Search and Retrieval (FOSAR) for missing baffle bolts and locking tabs

During this outage, PSEG replaced 189 degraded baffle bolts in the Unit 1 reactor vessel baffle assembly. This emergent project resulted in the extension of the outage schedule from 36 days to 106 days.

b. Findings

No findings were identified.

1R22 Surveillance Testing (71111.22 – 5 samples)

a. Inspection Scope

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

- Unit 1, Manual SI on April 17
- Unit 1, 11CA360, control air header supply check valve, as-found local leak rate test (LLRT) on April 22
- Unit 2, 21 RHR In-service Testing on April 1
- Unit 2, 22SW223, SW outlet valve to 22 CFCU, stroke time in the required evaluation range on May 3
- Unit 2, Reactor coolant system (RCS) elevated leakrate on May 17

b. Findings

No findings were identified.

Cornerstone: Emergency Preparedness

1EP6 Drill Evaluation (71114.06 – 1 sample)

Emergency Preparedness Drill Observation

a. Inspection Scope

The inspectors evaluated the conduct of a routine PSEG emergency drill on June 16 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, technical support center, and emergency operations facility to determine whether the event classification, notifications, and protective action recommendations were performed in accordance with procedures. The inspectors also attended the drill 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

No findings were identified.

2. RADIATION SAFETY

Cornerstones: Occupational and Public Radiation Safety

2RS1 Radiological Hazard Assessment and Exposure Controls (71124.01 – 6 samples)

a. Inspection Scope

The inspectors reviewed PSEG's performance in assessing and controlling radiological hazards in the workplace. The inspectors used the requirements contained in 10 CFR Part 20, TSs, applicable Regulatory Guides (RGs), and the procedures required by TSs as criteria for determining compliance.

Inspection Planning

The inspectors reviewed the PIs for the occupational radiation safety cornerstone, radiation protection (RP) program audits, and reports of operational occurrences in occupational radiation safety since the last inspection.

Radiological Hazard Assessment (1 sample)

The inspectors conducted independent radiation measurements during walk-downs of the facility and reviewed the radiological survey program, air sampling and analysis, continuous air monitor use, recent plant radiation surveys for radiological work activities, and any changes to plant operations since the last inspection to verify survey adequacy of any new radiological hazards for onsite workers or members of the public.

Instructions to Workers (1 sample)

The inspectors reviewed high radiation area work permit controls and use; observed containers of radioactive materials and assessed whether the containers were labeled and controlled in accordance with requirements.

The inspectors reviewed several occurrences where a worker's electronic personal dosimeter alarmed. The inspectors reviewed PSEG's evaluation of the incidents, documentation in the CAP, and whether compensatory dose evaluations were conducted when appropriate. The inspectors verified follow-up investigations of actual radiological conditions for unexpected radiological hazards were performed.

Contamination and Radioactive Material Control

The inspectors observed the monitoring of potentially contaminated material leaving the radiological controlled area and inspected the methods and radiation monitoring instrumentation used for control, survey, and release of that material.

Radiological Hazards Control and Work Coverage (1 sample)

The inspectors evaluated in-plant radiological conditions and performed independent radiation measurements during facility walk-downs and observation of radiological work activities. The inspectors assessed whether posted surveys; radiation work permits (RWPs); worker radiological briefings and RP job coverage; the use of continuous air monitoring, air sampling, and engineering controls; and dosimetry monitoring were consistent with the present conditions. The inspectors examined the control of highly activated or contaminated materials stored within the SF pools and the posting and physical controls for selected high radiation areas (HRAs), locked high radiation areas (LHRAs) and very high radiation areas (VHRAs) to verify conformance with the occupational PI.

Risk-Significant High Radiation Area and Very High Radiation Area Controls (1 sample)

The inspectors reviewed the procedures and controls for HRAs, VHRAs, and radiological transient areas in the plant.

Radiation Worker Performance and Radiation Protection Technician Proficiency (1 sample)

The inspectors evaluated radiation worker performance with respect to RP work requirements. The inspectors evaluated RP technicians in performance of radiation surveys and in providing radiological job coverage.

Problem Identification and Resolution (1 sample)

The inspectors evaluated whether problems associated with radiation monitoring and exposure control (including operating experience) were identified at an appropriate threshold and properly addressed in the CAP.

b. Findings

No findings were identified.

2RS2 Occupational As Low As is Reasonable Achievable Planning and Controls (71124.02 – 3 samples)

a. Inspection Scope

The inspectors assessed PSEG's performance with respect to maintaining occupational individual and collective radiation exposures as low as is reasonably achievable (ALARA). The inspectors used the requirements contained in 10 CFR Part 20, applicable RGs, TSs, and procedures required by TSs as criteria for determining compliance.

Inspection Planning

The inspectors conducted a review of Salem Station collective dose history and trends; ongoing and planned radiological work activities; previous post-outage ALARA reviews; radiological source term history and trends; and ALARA dose estimating and tracking procedures.

Radiological Work Planning

The inspectors selected the following radiological work activities based on exposure significance for review:

- RWP 13, Control Rod Drive Activities
- RWP 14 , Pressurizer Activities
- RWP 17, Primary SG Work

For each of these activities, the inspectors reviewed: ALARA work activity evaluations; exposure estimates; and exposure reduction requirements.

Verification of Dose Estimates and Exposure Tracking Systems

The inspectors reviewed the current annual collective dose estimate; basis methodology; and measures to track, trend, and reduce occupational doses for ongoing work activities. The inspectors evaluated the adjustment of exposure estimates or re-planning of work.

Source Term Reduction and Control (1 sample)

The inspectors reviewed the current plant radiological source term and historical trend, plans for plant source term reduction, and contingency plans for changes in the source term as the result of changes in plant fuel performance or changes in plant primary chemistry.

The inspectors observed radiological work activities and evaluated the use of shielding and other engineering work controls based on the radiological controls and ALARA plans for those activities.

Radiation Worker Performance (1 sample)

The inspectors observed radiation worker and RP technician performance during radiological work to evaluate worker ALARA performance according to specified work controls and procedures. Workers were interviewed to assess their knowledge and awareness of planned and/or implemented radiological and ALARA work controls.

Problem Identification and Resolution (1 sample)

The inspectors evaluated whether problems associated with ALARA planning and controls were identified at an appropriate threshold and properly addressed in the CAP.

b. Findings

No findings were identified.

2RS3 In-Plant Airborne Radioactivity Control and Mitigation (71124.03 – 3 samples)

a. Inspection Scope

The inspectors reviewed the control of in-plant airborne radioactivity and the use of respiratory protection devices in these areas. The inspectors used the requirements in 10 CFR Part 20, RG 8.15, RG 8.25, NUREG/CR-0041, TS, and procedures required by TS as criteria for determining compliance.

Inspection Planning

The inspectors reviewed the UFSAR to identify ventilation and radiation monitoring systems associated with airborne radioactivity controls and respiratory protection equipment staged for emergency use. The inspectors also reviewed respiratory protection program procedures and current PIs for unintended internal exposure incidents.

Engineering Controls (1 sample)

The inspectors reviewed operability and use of both permanent and temporary ventilation systems, and the adequacy of airborne radioactivity radiation monitoring in the plant based on location, sensitivity, and alarm set-points.

Use of Respiratory Protection Devices (1 sample)

The inspectors reviewed the adequacy of PSEG's use of respiratory protection devices in the plant to include applicable ALARA evaluations, respiratory protection device certification, respiratory equipment storage, air quality testing records, and individual qualification records.

Problem Identification and Resolution (1 sample)

The inspectors evaluated whether problems associated with the control and mitigation of in-plant airborne radioactivity were identified at an appropriate threshold and addressed by PSEG's CAP.

b. Findings

No findings were identified.

2RS4 Occupational Dose Assessment (71124.04 – 2 samples)

a. Inspection Scope

The inspectors reviewed the monitoring, assessment, and reporting of occupational dose. The inspectors used the requirements in 10 CFR Part 20, RGs, TSs, and procedures required by TSs as criteria for determining compliance.

Inspection Planning

The inspectors reviewed: RP program audits; National Voluntary Laboratory Accreditation Program (NVLAP) dosimetry testing reports; and procedures associated with dosimetry operations.

Source Term Characterization (1 sample)

The inspectors reviewed the plant radiation characterization (including gamma, beta, alpha, and neutron) being monitored. The inspector verified the use of scaling factors to account for hard-to-detect radionuclides in internal dose assessments.

External Dosimetry

The inspectors reviewed: dosimetry NVLAP accreditation; onsite storage of dosimeters; the use of "correction factors" to align electronic personal dosimeter results with NVLAP dosimetry results; dosimetry occurrence reports; and CAP documents for adverse trends related to external dosimetry.

Internal Dosimetry (1 sample)

The inspectors reviewed: internal dosimetry procedures; whole body counter measurement sensitivity and use; adequacy of the program for whole body count monitoring of plant radionuclides or other bioassay technique; adequacy of the program for dose assessments based on air sample monitoring and the use of respiratory protection; and internal dose assessments for any actual internal exposure.

Special Dosimetric Situations

The inspectors reviewed external dose monitoring of workers in large dose rate gradient environments.

Problem Identification and Resolution

The inspectors evaluated whether problems associated with occupational dose assessment were identified at an appropriate threshold and properly addressed in the CAP.

b. Findings

No findings were identified.

2RS5 Radiation Monitoring Instrumentation (71124.05 – 1 sample)

a. Inspection Scope

The inspectors reviewed performance in assuring the accuracy and operability of radiation monitoring instruments used to protect occupational workers during plant operations and from postulated accidents. The inspectors used the requirements in 10 CFR Part 20; RGs; applicable industry standards; and procedures required by TSs as criteria for determining compliance.

Inspection Planning

The inspectors reviewed: Salem Station UFSAR; RP audits; records of in-service survey instrumentation; and procedures for instrument source checks and calibrations.

Walkdowns and Observations

The inspectors checked the calibration and source check status of various portable radiation survey instruments and contamination detection monitors for personnel and equipment.

Calibration and Testing Program

The inspectors reviewed the calibration standards used for portable instrument calibrations and response checks to verify that instruments were calibrated by a facility that used National Institute of Science and Technology traceable sources.

Problem Identification and Resolution (1 sample)

The inspectors verified that problems associated with radiation monitoring instrumentation (including failed calibrations) were identified at an appropriate threshold and properly addressed in the CAP.

b. Findings

No findings were identified.

Cornerstone: Public Radiation Safety (PS)

2RS7 Radiological Environmental Monitoring Program (71124.07 – 2 samples)

a. Inspection Scope

The inspectors reviewed the Radiological Environmental Monitoring Program (REMP) to validate the effectiveness of the radioactive gaseous and liquid effluent release program and implementation of the Groundwater Protection Initiative (GPI). The inspectors used the requirements in 10 CFR Part 20; 40 CFR Part 190; 10 CFR Part 50, Appendix I; TSs; Offsite Dose Calculation Manual (ODCM); Nuclear Energy Institute 07-07; and procedures required by TSs as criteria for determining compliance.

Inspection Planning

The inspectors reviewed: Salem and Hope Creek Station's 2015 annual radiological environmental and effluent monitoring reports; REMP program audits; ODCM changes; land use census; UFSAR; and inter-laboratory comparison program results.

Site Inspection (1 sample)

The inspectors walked down various passive dosimeter and air and water sampling locations and reviewed associated calibration and maintenance records. The inspectors observed the sampling of various environmental media as specified in the ODCM and reviewed any anomalous environmental sampling events including assessment of any positive radioactivity results. The inspectors reviewed any changes to the ODCM. The inspectors verified the operability and calibration of the meteorological tower instruments and meteorological data readouts. The inspectors reviewed environmental sample laboratory analysis results, laboratory instrument measurement detection sensitivities, laboratory quality control program audit results, and the inter- and intra-laboratory comparison program results. The inspectors reviewed the groundwater monitoring program as it applies to selected potential leaking structures, systems, or components; and 10 CFR 50.75(g) records of leaks, spills, and remediation since the previous inspection.

Groundwater Protection Initiative Implementation

The inspectors reviewed: groundwater monitoring results; changes to the Groundwater Protection Initiative (GPI) program since the last inspection; anomalous results or missed groundwater samples; leakage or spill events including entries made into the decommissioning files (10 CFR 50.75 (g)); evaluations of surface water discharges; and

PSEG's evaluation of any positive groundwater sample results including appropriate stakeholder notifications and effluent reporting requirements.

Identification and Resolution of Problems (1 sample)

The inspectors evaluated whether problems associated with the REMP were identified at an appropriate threshold and properly addressed in PSEG's CAP.

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, 2015 through June 30, 2016.

- Unit 1 & 2 Unplanned Scrams
- Unit 1 & 2 Unplanned Power Changes
- Unit 1 & 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 IRs 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 PSEG entered issues into their 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 their CAP and periodically attended condition report screening meetings. The inspectors also confirmed, on a sampling basis, that, as applicable, for identified defects and non-conformances, PSEG performed an evaluation in accordance with 10 CFR Part 21.

b. Findings

No findings were identified.

.2 Semi-Annual Trend Review

a. Inspection Scope

The inspectors performed a semi-annual review of site issues to identify trends that might indicate the existence of more significant safety concerns. As part of this review, the inspectors included repetitive or closely-related issues documented by PSEG in the CAP and 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, MR assessments, and maintenance or CAP backlogs. The inspectors also reviewed PSEG CAP database for the first and second quarters of 2016 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.

a. Findings and Observations

No findings were identified.

Equipment Reliability (Steady)

The inspectors documented an adverse trend in either equipment reliability or unplanned entries into TS shutdown limiting conditions for operation (LCO) in each of the previous four semi-annual trend review periods (IRs 05000272; 311/2014003, 2014005, 2015002 and 2015004). In February 2016, in response to PSEG’s unplanned LCO performance goal not being met, PSEG performed Common Cause Evaluation (CCE) 70184208, Unplanned Shutdown LCO Goal Not Met. The CCE was completed in April of 2016, with the following results:

- A trend of data over an 18-month period from August 2014 through January 2016 identified 68 unplanned shutdown LCOs, which far exceeded the station goal of no more than 8 in a 12-month rolling average. PSEG’s CCE concluded: 1) 15 LCO entries were attributed to faulty parts; 2) 10 entries were attributed to equipment not being repaired in a timely manner; and 3) more follow up evaluations were warranted:
    - Work Group Evaluation (WGE) 70185245, “Follow up Evaluation from Unplanned shutdown LCOs,” was performed to further evaluate the 10 entries attributed to equipment not being repaired in a timely manner. PSEG attributed the cause to ineffective development and

implementation of equipment reliability strategies to ensure reliability until long-term elimination or mitigating actions were in place. Actions were assigned to develop bridging strategies for Plant Health Committee items and rollout to Station Oversight Committee (SOC) and Management Review Committee (MRC) an expectation that if an unplanned LCO occurs, a causal evaluation should be performed.

The inspectors noted some improvement in the area of unplanned entries into TS LCOs in recent months; specifically, 44 unplanned shutdown LCOs occurred from June 2015 to April 2016, but only seven occurred in the last 3 months of this 10 month period. The inspectors determined that the adverse trend of equipment failures did not constitute a performance deficiency, because the trend, by itself, did not constitute a violation of any NRC requirement. The inspectors inspected individual equipment failures as ROP baseline inspection samples documented in other sections of this report.

Main Control Room Deficiencies (Steady with recent improvement)

The inspectors noted an adverse trend in main control room deficiencies, as evident by a Red station performance metric dating back to mid-2015, when the station metric was redefined to align with the current industry metric. Specifically, in June of 2016, Unit 1 had 69 and Unit 2 had 45, versus a red performance metric threshold of 16 or more. However, the inspectors noted recent improvements in this area. Specifically, Unit 1 reduced the backlog from 99 in January 2016 to 69 in June, and Unit 2 reduced the backlog from 73 before the fall 2015 refueling outage to 45 in June 2016.

Untimely Reportability Determinations (Steady)

In Section 4OA2.2 of IR 2015-004, the inspectors identified that past operability determinations were untimely in supporting conclusions of LER reportability in 60 days, and listed multiple examples. In response to a LER 05000311/2016-001-000 being submitted well beyond 60 days from the occurrence of the event (see Sections 4OA2.3 and 4OA7 of this report), PSEG performed a review under apparent cause evaluation (ACE) 70183590, to determine the extent of condition relative to “missed or late” reports under 10 CFR 50.72 and 50.73. PSEG concluded the following: 1) The execution of CAP does not support timely completion of evaluation products to support 60-day LER submittals; 2) SOC and MRC have a low threshold for requesting reportability reviews; and 3) Salem has a high number of supplemental LERs relative to the industry (four in 2015 versus an industry average of less than one), indicating that CAP does not support timely cause evaluation completion, which require LERs to be supplemented. The inspectors noted that PSEG’s conclusion 3 above is consistent with a previously identified trend by the inspectors documented in Section 4OA2.2 of IR 2015002, which listed a steady increase in CAP evaluation products and subsequent trend of CAP products falling behind station timeliness goals. As a result of the ACE listed above, PSEG issued a temporary standing order to develop interim guidance until process improvements and controls were institutionalized for reportability, assigned corrective actions to develop procedure improvements and controls for accompanying reportability reviews, and to develop the appropriate change management plan for process changes to perform reportability reviews. The inspectors did not identify any actual violations of 10 CFR 50.72 or 50.73 during the performance of this inspection. The timeliness of reportability determinations remains a minor adverse trend.

Status Control and Human Performance Events (Improving)

The inspectors previously documented an adverse trend in status control in Section 4OA2.5 of IR 2014005. In December of 2015, Nuclear Oversight identified an adverse trend in status control. In February of 2016, PSEG completed a CCE in response to the adverse trend in plant status control. Additionally, status control was a focus area for the station in 2016. Since that time, the inspectors noted considerable improvement in the area of status control. Specifically, as of June 1, 2016, the station achieved 181 status control event free days. However, in recent months, the inspectors noted several human performance events that were not classified as status control events, though they reflect many of the same behavioral breakdowns in standards and fundamentals. Examples include:

- April 17: 1B EDG invalid actuation: During the performance of solid state protection system testing in Mode 6 (refueling), the 1B EDG unexpectedly started while an operator in the field was attempting to replace a light bulb on the test box. PSEG performed an investigation and determined that the most likely cause was due to the operator's finger bumping the block switch during the bulb replacement, which was enough pressure to allow the test block signal to be momentarily interrupted. PSEG reported this event as a telephone notification under 10 CFR 50.73(a)(1) and (a)(2)(iv)(A) on June 15.

- April 25: #1 Emergency Compressed Air Compressor trip during leak test - PSEG performed Quick Human Performance Investigation (QHPI) 70186240 and determined the operator in the control room did not understand the report from the equipment operator in the field, and determined that three-way communication was not used when it should have been.

- April 19: 22B circulator bypass valve operated in the wrong direction – PSEG performed QHPI 71085972 and determined that an equipment operator did not fully open the 22B circulator outlet valve prior to attempting remote closure of the 22B circulator bypass, which resulted in the bypass valve failing to stroke closed.

- March 27: Station Blackout (SBO) air compressor tripped – the equipment operator did not follow procedure while testing the SBO air compressor, resulting in a trip of the compressor (20723821).

The inspectors determined that none of the issues above were of more than minor significance, because none of them resulted in a significant plant transient or loss of a mitigating system. The inspectors determined that although the trend in events classified as status control had improved, the behaviors that contributed to them were still present.

.3 Annual Sample: Unit 2 Auxiliary Feedwater Loop Response Time Exceeded Technical Specifications

a. Inspection Scope

The inspectors performed an in-depth review of PSEG's identification, evaluation, and resolution following the discovery that a channel of the 21 AFW pump engineered safety feature actuation system (ESFAS) automatic actuation logic was inoperable.

On November 18, 2015, maintenance personnel compiling test data, collected on October 18, 2015, during the Unit 2 plant shutdown for the fall 2015 refueling outage, determined that the pump instrumentation loop time response exceeded test acceptance criteria. At the time, Unit 2 was shut down in a refueling outage and AFW was not required. The cause of the slow loop response was due to the isolation valve to the 21 AFW pump discharge pressure transmitter (2PA3450) being closed. The pressure transmitter provided input into the pump run-out protection and flow control circuit. The closed isolation valve caused the pressure transmitter to take longer to sense pump discharge pressure, which resulted in the slow opening of the pump SG flow control valves (valves 23AF21 and 24AF21). PSEG's investigation determined that the condition likely existed since April 20, 2015, following the completion of maintenance on the pressure transmitter. On January 19, 2016, PSEG determined that the condition was reportable to the NRC. PSEG initiated an ACE to determine the cause of the untimely review and evaluation of the surveillance data collected on October 18, 2015, and a WGE to determine the cause of the improperly positioned isolation valve to pressure transmitter 2PA3450. The inspectors performed an in-depth review of the ACE and WGE and corrective actions associated with the issues documented in Orders 70183590 and 70182519. PSEG submitted Licensee Event Report (LER) 05000311/2016-001-000, "AFW Loop Response Time Exceeded TSs," on March 21, 2016, as an operation or condition which was prohibited by the plant's TS. The inspectors' review of the LER is documented in Section 4OA3.1 of this report. Section 4OA7 documents the enforcement aspects related to the LER.

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

b. Findings and Observations

No findings were identified.

Maintenance personnel compiling 21 AFW pump loop time response test data identified the slow response times for valves 23AF21 and 24AF21, and entered this issue into the CAP as NOTF 20710947. During their review, PSEG identified that the instrument isolation valve for the 21 AFW pump discharge pressure transmitter (2PA3450) was closed versus the required position of open. The improperly positioned valve was promptly placed into the required open position. PSEG entered the improperly positioned valve into the CAP as NOTF 20709417, and performed a prompt investigation and a WGE. The inspectors determined that action taken by PSEG upon discovery of the slow response times for valves 23AF21 and 24AF21 were prompt and appropriate.

The inspectors reviewed Order 70182519, which documented the WGE for instrument isolation valve for 2PA3450 being found in the incorrect position. Although the actual cause of the improperly positioned isolation valve was indeterminate, PSEG concluded that the condition most likely existed since April 20, 2015, when maintenance was last performed on 2PA3450. Corrective actions included plans to install human factors tools (i.e., additional measure devices) on all transmitter isolation valves located in both the Unit 1 and 2 AFW instrumentation panels. The inspectors concluded that PSEG's planned corrective action was appropriate.

The inspectors reviewed the timeline of events from the collection of test data on October 18, 2015, until the submittal of the LER for the condition prohibited by TS related to the slow instrument loop response time for the 21 AFW pump. The inspectors concluded that information was available to PSEG personnel on November 20, 2015, that the condition was potentially reportable when the cause was determined to be due to the incorrectly positioned instrument isolation valve to 2PA3450. However, the required LER was not submitted until March 21, 2016.

The inspectors reviewed PSEG's investigation into the reportability timeliness issue, as documented in Order 70183590. PSEG determined that the cause was due to work tracking assignments not being made to facilitate identification and completion of the required past operability review in accordance with Engineering standard practice. The normal practice to evaluate issues for potential past operability/reportability is for the SOC to assign a 'technical evaluation' to Engineering to review. In this case an 'action item' was assigned to Engineering versus a 'technical evaluation'. The due dates for 'action items' are allowed to be extended by the assignee whereas, the process of extending 'technical evaluations' has more stringent controls. Therefore, the priority of the 'action item' was not established at the correct threshold by the assigned engineering supervisor. This resulted in extensions of the due date for the past operability/reportability review. PSEG's corrective actions taken or planned included issuance of an Operations standing order, which provided additional interim guidance for performing past operability and reportability reviews, and to develop process improvements and controls for accomplishing past operability and reportability reviews. The inspectors concluded that the actions taken or planned appeared to appropriately address the reportability timeliness issue. In accordance with IMC 0612, "Power Reactor Inspection Reports," the above timeliness of reportability issue constituted a violation of minor significance that is not subject to enforcement action in accordance with the Enforcement Policy.

As discussed in Order 70183590, PSEG recognized that the SOC inappropriately assigned an 'action item' versus the more appropriate 'technical evaluation' to Engineering for the past operability/reportability review. The inspectors observed that actions taken by PSEG did not directly address the shortfall of the SOC in this case. The inspectors noted that there was a low level assignment for the SOC to evaluate for a human performance crew clock reset; however, the clock reset was determined to not be necessary. The inspectors noted that the other actions taken or planned discussed above appeared to be adequate to address the inappropriate extensions of past operability and reportability reviews.

In NRC Inspection Report 05000272, 05000311/2015004, dated February 10, 2016, a problem identification and resolution adverse trend was documented related to past operability determinations being untimely in supporting conclusions of LER reportability within sixty days. The inspectors concluded that the untimely past operability and reportability review of the failed 21 AFW pump instrument loop time response test as an additional example of the adverse trend identified in NRC IR 05000272, 05000311/2015004 and updated in Section 4OA2.2 of this report. At the end of this inspection period, PSEG had not entered this adverse trend into their CAP.

.4 Annual Sample: Struthers-Dunn Relay Failures in Safety-Related Applications

a. Inspection Scope

The inspectors performed an in-depth review of PSEG's ACE and corrective actions associated with NOTF 20681569 related to a 21 containment spray (CS) pump failure to start. The 21 CS pump failed to start on October 2, 2015, during post-maintenance testing following scheduled maintenance. The 21 CS pump failure to start was investigated by PSEG during subsequent troubleshooting. Additionally, a failure modes and causal table determined the most likely cause for the failure to start was from a starting relay high contact resistance. PSEG postulated that contact contamination created a high resistance condition that was subsequently cleared due to the wiping action of the relay contact. The starting relay was a Struthers-Dunn Model 219BBX-240 and was replaced. The failed relay was sent for failure analysis to an offsite laboratory. The lab was unable to repeat the high resistance contact operation that was observed at Salem. The lab functional testing did not yield any deficiencies or failure mechanisms.

The inspectors assessed PSEG's problem identification threshold, causal analyses, technical analyses, extent of condition reviews, and the prioritization and timeliness of corrective actions to determine whether PSEG was appropriately identifying, characterizing, and correcting problems associated with this issue. The inspectors reviewed the circumstances of this relay failure issue to ascertain the appropriateness of corrective actions. The inspectors also assessed PSEG's corrective actions to prevent recurrence. The inspectors compared the actions taken to the requirements of PSEG's CAP and 10 CFR Part 50, Appendix B, Criterion XVI, Corrective Action. In addition, the inspectors reviewed documentation associated with this issue, including condition reports, and interviewed engineering personnel to assess the effectiveness of the planned and implemented corrective actions.

b. Findings and Observations

No findings were identified.

The Struthers-Dunn relays in critical applications were all replaced in 1996 and 1997 during extended unit shutdowns. From about 2000 to 2015, Salem experienced Struthers-Dunn relay failures in critical applications at about one MR functional failure per year. In May 2013, after a Struthers-Dunn relay failure associated with the 15 containment fan cooling unit (CFCU), PSEG developed extensive corrective actions to revise preventive maintenance (PM) templates and determine an appropriate replacement periodicity. An accelerated testing program was a corrective action and completed in March 2014 to determine the number of relay operations when the contacts gold flashing began to wear away exposing the silver base. Exposing the silver contact base leads to a corrosion condition called sulfidation creating a high resistance between relay contacts. Offsite laboratory analysis of previous Struthers-Dunn relays had identified worn gold flashing and sulfidation.

PSEG determined from the accelerated relay testing program that Struthers-Dunn relays in CFCU applications should be replaced every 10 years. The CFCUs have more frequent equipment on/off cycles compared to other critical Struthers-Dunn applications. PSEG determined all other Struthers-Dunn relay replacements should be replaced at 20 years. PSEG established the 20 year replacement interval based on 400 relay operations for the equipment considered. However, the inspectors noted that for some relay applications, major gold flashing wear or wiping resulting in areas of exposed silver was observed from the accelerated failure testing results at just 350 relay operations. PSEG generated notification 20734284 in response to the inspectors' observation for resolution and to reevaluate the intended 20 year replacement periodicity.

The corrective action due dates for the final PM templates are due in August 2016. PSEG accelerated and completed the Struthers-Dunn relay replacements in all CFCU applications. The inspectors noted that if PSEG finalizes a 20 year replacement for non-CFCU applications, considering that all Struthers-Dunn relays were replaced in 1996 to 1997, then all Struthers-Dunn relays would now or in the near term require replacement. PSEG initiated notification 20734280 in response to the inspectors' observation for resolution.

.5 Annual Sample: Unexpected Number of Degraded Baffle-Former Bolts Discovered in the Unit 1 Reactor Pressure Vessel

a. Inspection Scope

The inspectors performed an in-depth review of PSEG's technical evaluation and corrective actions associated with NOTF 20726264 for baffle-former ("baffle") bolts found with indications of degradation during the spring 2016 Salem Unit 1 24th refueling outage (1R24). PSEG performed ultrasonic examinations of the baffle bolts in accordance with their procedures in response to recent industry operating experience and 1R24 visual examination results indicating 18 visually damaged baffle bolts. After an unexpected number of degraded baffle bolts were discovered, PSEG staff entered the issue into their corrective action program as NOTF 20727538 and reported the issue to the NRC as Event Notification No. 51902 on May 3, 2016, because the as-found number and location of degraded bolts, which were mainly concentrated in three of the eight baffle assemblies, represented an unanalyzed condition. PSEG staff completed corrective actions to replace 189 of 192 potentially degraded baffle bolts on Unit 1. As documented in Section 1R18, PSEG did not remove and replace three bolts that were potentially degraded due to difficulties encountered during the removal/replacement process.

The baffle bolts help secure vertical plates (also referred to as baffle plates) inside the reactor vessel, which then forms a structure surrounding the reactor fuel assemblies to orient the fuel and to direct coolant flow through the core. A sufficient number of baffle bolts are required to remain intact to secure the baffle plates in place so as to not affect control rod insertion or impede emergency core cooling flow during postulated accident conditions. Bolt heads that separate and are no longer held in place by bolt lock-tabs can also become a loose parts concern.

The inspectors assessed whether PSEG acceptable baffle bolt pattern analysis for Unit 1 was completed in accordance with the NRC-approved methodology and provided appropriate structural margin for the next cycle of operation to ensure the Unit 1 baffle plates will remain in place during both normal operation and limiting postulated accident conditions. The inspectors also assessed whether PSEG's evaluations of the baffle bolts installed in Salem Unit 2 were technically sufficient to conclude the Unit 2 baffle assembly will perform as intended until the next planned refueling outage, at which time PSEG plans to examine the bolts. The inspectors reviewed PSEG's procedures for determining the functionality and operability of degraded systems, components and structures as they relate to Unit 2. Additionally, the inspectors interviewed PSEG engineering personnel and contractor staff to discuss the results of PSEG's technical evaluations and to assess the effectiveness of the implemented and planned corrective actions.

The inspectors assessed PSEG's problem identification threshold, cause analyses, extent of condition, compensatory actions, and the prioritization and timeliness of PSEG's corrective actions to determine whether PSEG staff were properly 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 PSEG's corrective action program, operability determination process, and the requirements of 10 CFR Part 50, Appendix B. The inspectors observed portions of baffle bolt replacement activities at Unit 1 and reviewed the final visual examination of the baffle bolts and plates once the work was completed.

b. Observations

The NRC responded to the initial discovery of an unexpected number of baffle bolts found degraded at Salem Unit 1 by implementing a comprehensive inspection plan consisting of various baseline inspection samples to assess the extent of the issue and to determine the necessary NRC actions. A previously planned ISI sample (Refer to Section 1R08) was expanded to include a review of the capability of the NDE techniques for ultrasonically testing (UT) the baffle bolts, to evaluate the UT results, and to observe a portion of bolt replacement activities on-site. Two permanent modification samples (Refer to Section 1R18) were conducted to review the design change package and evaluations associated with the new, replacement baffle bolts, and to review the PSEG design change package documenting the as-left baffle bolting pattern in Unit 1. NRC resident inspectors reviewed PSEG's foreign material controls and loose parts analysis (Refer to Section 1R20) to address the potential for missing bolt heads and concluded it would not impact safe operation of the plant.

NRC Region I based inspectors, accompanied by an expert from the NRC Office of Nuclear Reactor Regulation, completed this annual problem identification and resolution inspection sample, to verify that PSEG's evaluations and corrective action to replace Unit 1 baffle bolts were completed in accordance with NRC approved methodology to support a conclusion that the Unit 1 baffle assembly meets the plant design basis. The inspectors also reviewed the adequacy of PSEG's technical evaluations completed to determine whether there is a reasonable expectation the Unit 2 baffle assembly will perform as intended during the current operating cycle. The results of this review are discussed herein and in Section 1R15 of this report.

At the completion of this inspection, PSEG's conduct of a RCE to determine the causes of the failure of the baffle bolts in Unit 1 was ongoing. The inspectors determined PSEG's RCE will not be completed until after laboratory tests and analyses, planned for fall 2016, are performed on a sample of the bolts removed from Unit 1. PSEG's technical evaluation discussed the cause of the degraded baffle bolts as primarily due to IASCC. This determination was based on industry operating experience related to baffle bolt failure in both foreign and domestic plants, is a known degradation mechanism and the operational and physical characteristics of both Salem plants indicate that they are susceptible to this mechanism. The inspectors reviewed PSEG's technical evaluation and the supporting operating experience related to baffle bolt failures at other plants. IASCC is a cracking mechanism that occurs over a long period of time when susceptible metals are exposed to neutron radiation from the reactor core and stresses as part of normal design and operation. The inspectors determined PSEG identified the likely cause of the baffle bolt degradation and their plans to complete a RCE when additional metallurgical information was available was appropriate.

Following identification of the degraded baffle bolts on Unit 1, PSEG's immediate corrective action was to analyze the as-found condition and begin replacing bolts that either had visual indications of bolt failure (protruding bolt head for example), did not pass UT examination, or were not accessible for UT examination. The as-found number and pattern of these bolts exceeded the acceptance criteria in the plant's analysis that was prepared in advance of the baffle bolt examinations; therefore, PSEG reported this discovery to the NRC as an unanalyzed condition in Event Notification 51902 on May 3, 2016. PSEG staff completed corrective actions to replace 189 of 192 potentially degraded baffle bolts. PSEG did not remove and replace three bolts that were potentially degraded due to difficulties encountered during the removal/replacement process. As previously documented in Section 1R18, one bolt had an indication during ultrasonic testing but was not visibly damaged. The second bolt was inaccessible for ultrasonic testing, which would have required replacement. The third bolt had successfully passed an ultrasonic test but had a visual indication on one of the lock bar welds which may have indicated a crack in the weld.

The inspectors determined that PSEG staff performed an acceptable bolt pattern analysis that evaluated the replacement bolt pattern for Unit 1. The inspectors found the results of the analysis accounted for a conservative failure rate of bolts and provided appropriate margin for one cycle of operation. The inspectors verified that PSEG's methodology for its acceptable bolt pattern analyses, including its determination of margin, was consistent with the NRC-approved methodology in topical report WCAP-15029-NP-A (ML15222A882). The inspectors determined that PSEG staff tracked corrective actions to re-examine the Unit 1 baffle bolts during the next planned refueling outage. The inspectors noted the new baffle bolts were made of a material (316 SS) with improved resistance to IASCC and included an improved design to reduce the stresses at the head to shank transition, both of which are enhancements compared to the original bolts.

As part of an extent of condition assessment, PSEG entered NOTF 20727590 in its corrective action program to evaluate the potential for degraded baffle bolts on Unit 2. PSEG operators performed an IOD and concluded that the baffle assembly was operable. PSEG staff performed a subsequent technical evaluation that concluded Unit 2 would experience less baffle bolt degradation than Unit 1 based on several plant factors. The inspectors reviewed PSEG's technical evaluations, including the inputs for the operability determination, and noted that PSEG staff concluded there was not a degraded condition at Unit 2. In consideration of the guidance in PSEG's operability procedure and operating experience from Unit 1 and other plants, the NRC issued an NCV in this report because PSEG did not perform an OPEval for Unit 2 as a follow-up to the IOD for the potential impact on supported systems controlled by the Technical Specifications (Refer to Section 1R15).

As a corrective action, PSEG staff performed OpEval 2016-015 and demonstrated that the Unit 2 baffle assembly remained operable. The inspectors concluded that this supplemental evaluation provided adequate technical justification for the continued operation of Unit 2 until the next refueling outage in spring 2017, at which time PSEG plans to examine the baffle bolts. PSEG also implemented compensatory measures to monitor the reactor coolant system for any signs of fuel leakage, which could be an indicator of baffle bolt failures and to generate additional contingency actions in response to indications of increased unidentified leakage or receipt of a metal impact monitoring system alarm.

The inspectors reviewed Westinghouse Nuclear Safety Advisory Letter NSAL-16-1, which discussed the results of recent baffle bolt inspections and provided Westinghouse's recommendations on this issue. The letter described the plants as most susceptible (i.e. Tier 1a) to this degradation as Westinghouse 4-loop reactors limited to those with a down-flow configuration and using Type 347 stainless steel. A non-proprietary presentation on the contents of NSAL-16-1 can be found at ML16202A063. The inspectors noted the recommendation was to complete UT volumetric examination of the baffle bolts at the next scheduled refueling outage, and that PSEG had already planned this action for Unit 2. The inspectors determined PSEG's overall response to the issue was commensurate with the safety significance, was timely, and included appropriate compensatory actions. The inspectors concluded that the actions completed and planned were reasonable to address the ongoing aging management of baffle bolts.

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

.1 Plant Events (2 samples)

a. Inspection Scope

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

- Unit 1, Baffle to former bolts found broken or degraded on May 3 (EN 51902)
- Unit 2, Reactor trip from main turbine trip on June 28 (EN 52048)

b. Findings

No findings were identified.

.2 <u>(Closed) LER 05000311/2016-001-000</u>: Auxiliary Feedwater Loop Response Time Exceeded Technical Specifications

a. <u>Inspection Scope</u>

While evaluating surveillance instrumentation loop time response test data associated with the 21 AFW pump that was collected during the Unit 2 plant shutdown for the fall 2015 refueling outage, PSEG determined that a channel of the pump's ESFAS automatic actuation logic was inoperable. In November 2015, PSEG personnel identified the slow loop response time during surveillance testing. The cause of the slow loop response was due to the isolation valve to the 21 AFW pump discharge pressure transmitter (2PA3450) being closed. The pressure transmitter provided input into the pump run-out protection and flow control circuit. The closed isolation valve caused the pressure transmitter to take longer to sense pump discharge pressure which resulted in slow opening of the pump steam generator flow control valves (valves 23AF21 and 24AF21). PSEG's investigation determined that the condition existed since April 20, 2015, following the completion of maintenance on the pressure transmitter. An engineering review concluded that, although the AFW loop response time test results did not satisfy TS requirements, the accident analysis assumptions remained valid and the condition did not result in an unanalyzed condition. This issue is discussed in more detail in Section 4OA2.1 of this report. No other issues were identified during the review of the LER. This LER is closed.

b. <u>Findings</u>

The enforcement aspects of this violation are discussed in Section 4OA7.

.3 <u>(Closed) LER 05000311/2016-002-00</u>: Automatic Reactor Trip Due to Main Turbine Trip

a. <u>Inspection Scope</u>

On February 4, Salem Unit 2 automatically tripped from approximately 74 percent power. Power had been reduced at the beginning of dayshift to support a 500 kV transmission line outage. The reactor trip was due to a Main Turbine trip caused by a Main Generator Protection signal initiated by a main generator AVR volts/hertz over excitation protection relay. All emergency core cooling systems and emergency safeguards feature systems functioned as expected. PSEG submitted this LER in accordance with 10 CFR 50.73 (a)(2)(iv)(A), "Any event or condition that resulted in manual or automatic actuation of any of the systems listed in paragraph (a)(2)(iv)(B)," specifically automatic actuation of the Reactor Protection System and the Auxiliary Feedwater System for this event. The inspectors reviewed the LER, the associated cause evaluation, and interviewed PSEG staff. This LER is closed.

b. <u>Findings</u>

<u>Introduction</u>. A Green, self-revealing FIN was identified against MA-AA-716-010, "Maintenance Planning Process," Revision 18, when PSEG WOs did not specify the appropriate procedure to perform satisfactory modification testing of the main generator AVR protective relay (model STV1). Consequently, the relay actuated below its design setpoint on February 4, 2016, resulting in an automatic trip of the Unit 2 main turbine and reactor.

Description. On February 4, 2016, Unit 2 experienced an automatic main turbine and reactor trip from approximately 74 percent power, initiated by a trip of the main generator AVR STV 1 relay. The STV1 is designed to protect the main generator, main power transformers, and auxiliary transformer from over-excitation due to over-voltage operation, and consists of an adjustable pickup dial setting between 1.8 and 2.5 voltz/hertz (V/Hz), ranging from 108 – 150 V at 60 Hz. PSEG design calculation ES-7.007, "Salem Unit 2 Generator and Transformer Protective Relay Setpoint Determination," Revision 5, established a design setpoint for the STV1 relay of 138 V at 60 Hz, corresponding to a V/Hz dial setting of 2.3, with an associated time delay of 45 seconds. Just prior to the Unit 2 trip on February 4, the main generator was operating at approximately 26.1 kV following a manual MVAR adjustment, which corresponded to 2.175 V/Hz sensed at the STV1. After the Unit 2 trip, PSEG troubleshooting determined the as-found pick-up value of the STV1 was 2.17 V/Hz. The post-trip sequence-of-event data showed the STV1 time delay unit picked up 45 seconds after exceeding 2.17 V/Hz, which tripped the AVR and resulted in a loss of field to the main generator, thereby causing a turbine trip and coincident reactor trip.

In response to the Unit 2 reactor trip, PSEG performed RCE 70183932, "Unit 2 Automatic Reactor Trip on Generator Protection," to determine why the STV1 relay actuated below the design setpoint. PSEG identified two root causes: 1) setpoint drift due to a damaged rheostat; and 2) the damaged rheostat was not identified due to an inadequately planned work order that specified a less than adequate post-modification test method. PSEG DCP 80109718, "Salem Unit 2 AVR Replacement," supplement 10, documented that a "modification test" was required for the STV1 relay in accordance with Relay Department test procedures, which subsequently required the use of an engineering-approved Relay Test Order (RTO). However, Maintenance Planning prepared WO 60122561-0014 to perform STV1 modification testing without specifying the applicable test procedures. MA-AA-716-010, step 4.5.7, states "If approved procedure(s) are available which cover all or part of the work scope, then specify in the work package to perform work in accordance with the procedure(s)." Additionally, step 3.1.1 states, in part, "Maintenance Planners are responsible to interface with: System Engineers for providing supplemental technical direction on a case by case basis as needed;" and "Maintenance Shops to obtain information needed to produce an adequately detailed work package."

Additionally, the RCE determined that WO 60122561-0014 directed the PSEG LTS department to perform modification testing of the STV1 relay. However, LTS utilized different testing procedures than the Relay department procedures specified in the DCP. The LTS modification testing performed on October 5, 2015, did not functionally test the STV1 relay at its design setpoint of 138 volts at 60 Hz, which corresponded to a dial setting of 2.3 as discussed above. The RCE determined the manufacturer-specified acceptance testing required verifying the V/Hz pick-up was within one percent of all V/Hz adjustable dial settings, whereas the LTS procedure required the V/Hz pickup at a four percent tolerance on the 2.0 dial setting, or four percent of 120 volts at 60 Hz. The STV1 relay pickup value from the LTS testing on October 5, 2015, fell outside of the one percent tolerance specified by the manufacturer, and LTS did not have a technical basis to support an allowable tolerance of four percent. The RCE determined that returning the relay to the manufacturer-specified setting of one percent would have required adjusting the damaged rheostat to a position where the relay would not have functioned, and therefore would have resulted in a failed acceptance test that would have prevented the relay from being installed in the plant. The inspectors verified that the STV1 RTO specified a one percent tolerance at the design setpoint of 138 volts at 60 Hz.

Analysis. The inspectors determined that a performance deficiency existed because PSEG WOs did not specify the appropriate procedure to perform satisfactory modification testing of the main generator AVR protection relay STV1. This issue was more than minor since it was associated with the procedure quality attribute of the Initiating Events cornerstone and adversely impacted its objective to limit the likelihood of events that upset plant stability (main generator and turbine trip) and challenge critical safety functions. Specifically, due to a work order that was not planned properly, PSEG did not test the STV1 relay at the applicable design setpoint and manufacture-specified tolerance. Consequently, the relay actuated below its design setpoint on February 4, 2016, resulting in an automatic trip of the Unit 2 main turbine and reactor. Using IMC 0609, Attachment 4 and Appendix A, Exhibit 1, the inspectors determined that this finding was of very low safety significance, or Green, since mitigating equipment relied up to transition the plant to stable shutdown remained available.

The finding had a cross-cutting aspect in the area of Human Performance, Work Management, in that the organization implements a work process that includes the need for coordination with different groups or job activities. Specifically, the PSEG process for planning the STV1 relay modification test WO included the need for maintenance planners to coordinate with engineering to provide design setpoint and tolerance specifications, as well as electrical maintenance departments to verify appropriate test procedures were specified in the WO. The inspectors determined that PSEG did not adequately implement the work process in accordance with MA-AA-716-010. [H.5]

Enforcement. MA-AA-716-010, Maintenance Planning Process, Revision 18, step 4.5.7, states “If approved procedure(s) are available which cover all or part of the work scope, then specify in the WO to perform work in accordance with the procedure(s).” Contrary to the above, PSEG did not specify in the WO to perform work in accordance with approved Relay department test procedures, and the associated RTO, for modification testing of the STV1 relay on October 5, 2015. Specifically, due to a work order that was not planned properly, PSEG did not test the STV1 relay at the applicable design setpoint and manufacturer-specified tolerance. Consequently, the relay actuated below its design setpoint on February 4, 2016, resulting in an automatic trip of the Unit 2 main turbine and reactor. PSEG entered the issue in CAP as notification 20717849 and performed RCE 70183932. Planned corrective actions included replacing the failed STV1 relay with a properly tested STV1 relay, verifying other STV relays were appropriately tested as an extent of condition, and revising LTS department relay test procedures to ensure all applicable acceptance criteria are incorporated. This finding does not involve enforcement action because no violation of a regulatory requirement was identified. Because this finding does not involve a violation and is of very low safety significance, it is identified as a Finding. **(FIN 05000311/2016002-03, Inadequate Work Order Planning Results in Main Generator AVR STV Relay Trip)**

4OA5 Other Activities

.1 (Closed) URI 05000272; 311/2015008-01: Inadequate Maintenance Rule System Performance Criteria (PC) Selection

a. Inspection Scope

In IR 05000272; 311/2015-008, inspectors identified a URI associated with inadequate Maintenance Rule Performance Criteria selection.

During this review the inspectors noted approximately 25 high safety significant systems (HSS) with reliability PC greater than two maintenance preventable functional failures (MPFFs). According to ER-AA-310-1003, Attachment 3, flowchart "Process for Selecting Reliability Performance Criteria," HSS SSCs, with reliability PC greater than or equal to two MPFFs require SSC past performance documentation. When the inspectors requested that PSEG provide past performance documentation for the HSS SSCs with reliability PC greater than two MPFFs, PSEG provided documentation of HSS SSC PC approval from 1997, when the MRule Program was first implemented by PSEG. The inspectors determined this documentation did not support the assigned PC, because it did not consider the last 18 years of SSC past performance.

The inspectors also reviewed ER-AA-310-1007, "Maintenance Rule – Periodic (a)(3) Assessment." Step 5.11.1.4 states to determine that the number of MPFFs allowed per evaluation period is consistent with the assumptions in the probabilistic risk assessment (PRA). Contrary to ER-AA-310-1007, step 5.11.4, the last two periodic (a)(3) assessments performed by PSEG: April 1, 2011, through September 9, 2012; and October 1, 2012 through June 30, 2014; did not verify that the number of MPFFs allowed per evaluation period were consistent with the assumptions in the PRA. Additionally, ER-AA-310-1003, step 4.3.2, states, in part, that unless justified and approved by the Maintenance Rule Expert Panel, the number of MPFFs selected, as a Reliability PC, may **not** be higher than the PRA-supplied number of functional failures.

The inspectors determined that the failure to meet ER-AA-310-1007, step 5.11.4, and ER-AA-310-1003, step 4.3.2, was a performance deficiency. However, at the time of inspection, as documented in the IR referenced above, the inspectors did not have the information needed to determine whether the performance deficiency was more than minor. The inspectors reviewed PSEG's actions in response to the URI, to determine whether the performance or condition of HSS SSCs was effectively controlled through the performance of appropriate preventive maintenance under 10 CFR 50.65(a)(2), and also to determine if those HSS SSCs being monitored under 10 CFR 50.65(a)(1) were assigned appropriate goals and monitoring when considered against the appropriate reliability PC threshold.

b. Findings

No findings were identified.

PSEG captured the performance deficiency associated with the URI in the CAP under notifications 20694641, 20699573, and 20716722. In response, the PSEG Engineer performed detailed reviews of all the HSS reliability performance criteria against the basic event failure assumptions in the most recent PRA model. For any systems that were identified to have reliability performance criteria deviations from the PRA basic event failure data, performance criteria changes were proposed to more closely align with the PRA. Any proposed changes to system performance criteria were scheduled for review by the Maintenance Rule Expert Panel, including a review of system performance during the last 36 months. The inspectors observed a sampling of the Expert Panel meetings, and reviewed meeting minutes for several others. Upon completion of the PSEG system reviews and expert panel meetings, a total of 12 HSS had reliability performance criteria reductions to more closely align with PRA failure data. Five of the 12 systems were already being monitored under 10 CFR Part 50.65(a)(1) prior to the reduction in performance criteria. None of the 12 systems were moved to (a)(1) as a result of the performance criteria reductions. The inspectors sampled the performance criteria adjustments to determine if HSS classified under (a)(2) were being appropriately monitored, and to verify that (a)(1) systems had appropriate goals assigned. No performance deficiencies were identified. The inspectors determined that PSEG's scope of actions restored compliance with ER-AA-310-1007, step 5.11.4, and ER-AA-310-1003, step 4.3.2.

This URI is closed.

.2 License Renewal Commitments Inspection - Phase I Observation of License Renewal Activities (71003 – 1 sample)

a. Inspection Scope

License renewal inspections verify the license conditions added as part of the renewed operating license, regulatory commitments, and selected aging management programs, and are implemented in accordance with 10 CFR Part 54, "Requirements for the Renewal of Operating Licenses for Nuclear Power Plants." This inspection was completed during 1R24 to observe the implementation of select aging management program activities that are only available for observation during a refueling outage. This inspection is described as "Phase 1" in NRC Inspection Manual Procedure 71003, Post-Approval Site Inspection for License Renewal and is intended to be completed during the last refueling outage prior to a nuclear power facility entering the period of extended operation.

As part of this review the inspectors observed the implementation of aging management programs and activities described in the license conditions, and regulatory commitments, as well as any testing or visual inspections of systems, structures, and components which are only accessible at reduced power levels or during a refueling outage.

The inspectors observed the ultrasonic thickness inspection of 1S-FWR-P-21-L1, which is a 6-inch diameter elbow in the Feedwater Recirculation system. The component is part of the No. 12 SG Feed pump's 24-inch discharge header. The inspectors observed the test grid being applied and the recording of measurements in accordance with test procedure OU-AA-335-004 under the flow accelerated program guidance ER-AA-430-1001 as directed by WO 30285966.

The inspectors also observed the preparation for the replacement of a Moisture Separator Reheat Drain system 4-inch diameter piping section. The line is the drain from the No. 11 West Moisture Separator Reheat Main Steam Coil going to the No. 11 West Main Steam Coil Drain Tank. This was the planned replacement of 27' feet of piping with corrosion resistant P22/Chrome Moly material. The work was being performed on the 140' Turbine deck, under WO 60123316.

The inspectors observed the No. 12C Miscellaneous Drains drain manifold replacement spool piece. This 12-inch diameter manifold receives three drain lines from the No. 15A, B, & C Bleed Steam lines and is being replaced with corrosion resistant P22 (Chrome Moly) material. The replacement was in progress and performed under WO 60123347.

After reviewing WO 60120251, the inspectors observed the removal and evaluation of random samples of inaccessible Salem Unit 1 containment liner covered by insulation. The inspectors observed the containment interior liner insulation being removed, unremediated containment liner sections, and containment liner sections that were cleaned, brushed, and prepared for panel installation. The inspectors reviewed ultrasonic thickness data to verify whether the program was in conformance with American Society of Mechanical Engineers, Boiler and Pressure Vessel Code, Section XI.

b. Findings and Observations

No findings were identified.

4OA6 Meetings, Including Exit

On July 28, 2016, the inspectors presented the inspection results to Mr. Robert DeNight, Salem Operations Director, and other members of the PSEG staff. On August 11, 2016, an additional exit meeting was conducted and the inspectors presented inspection results specific to the baffle bolt issues in this report to Mr. Eric Carr, Acting Station Vice President. During the August 11, 2016 exit meeting, PSEG management stated they may contest NCV 05000311/2016002-02 (Section 1R15), in a written response within 30 days of the date of this inspection report, using the process described in the cover letter. Additionally, the inspectors verified that no proprietary information was retained by the inspectors or documented in this report.

4OA7 Licensee-Identified Violations

The following violation of very low safety significance (Green) was identified by PSEG and is a violation of NRC requirements which meets the criteria of the NRC Enforcement Policy, for being dispositioned as an NCV.

- TS LCO 3.3.2.1 requires the ESFAS instrumentation channels and interlocks shown in Table 3.3-3 shall be operable. Table 3.3-3, Function 8, requires two channels of AFW automatic actuation logic to be operable in Modes 1, 2, and 3. With the number of operable channels one less than the required number of channels, TS LCO 3.3.2.1 requires the inoperable channel to be restored to operable status within 6 hours or, be in at least Hot Standby within the next 6 hours and in at least Hot Shutdown within the following 6 hours. Contrary to TS LCO 3.3.2.1, one less than the required number of channels of AFW automatic actuation logic were operable from April 20, 2015, until Unit 2 entered Mode 4 for a scheduled refueling outage on October 23, 2015. This was due to the 21 AFW pump loop time response being greater than the allowed TS value because the isolation valve for the pressure override defeat pressure transmitter was in the closed position. PSEG entered this issue into the CAP as NOTFs 20709417, 20716352, 20710947, and 20711796.

This performance deficiency was more than minor because it was associated with the human performance attribute of the Mitigating System cornerstone, and adversely affected the cornerstone objective of ensuring the reliability and capability of systems that respond to initiating events to prevent undesirable consequences. The inspectors evaluated this finding using IMC 0609, Appendix A, “The Significance Determination Process for Findings At-Power,” Exhibit 2. The inspectors determined that the finding was of very low safety significance (Green) because the finding did not represent an actual loss of function of at least a single train for greater than its TS allowed outage time.

ATTACHMENT: SUPPLEMENTARY INFORMATION

SUPPLEMENTARY INFORMATION

KEY POINTS OF CONTACT

Licensee Personnel
J. Perry, Site Vice President
E. Carr, Acting Site Vice President
J. Barkhamer, PSEG Engineer
J. Bergeron, Superintendent of Instrumentation and Controls
T. Cachaza, Senior Regulatory Compliance Engineer
R. Cary, Environmental Coordinator
L. Clark, Instrument Supervisor
B. Daly, Nuclear Environmental Affairs, Sustainability
D. Denelsbeck, RP Support Supervisor
B. Down, PSEG Engineer
P. Essner, System Engineer
P. Fabian, Salem Steam Generator Engineer
T. Giles, Salem ASME Section XI Program Owner
F. Grenier, RP Supervisor, Dosimetry
M. Hassler, Salem Radiation Protection Manager
B. Kerkorian, Salem Steam Generator Supervisor
D. Kolasinski, Senior Engineer
A. Kraus, Manager, Nuclear Environmental Affairs
T. MacEwen, Principal Compliance Engineer
J. Mallon, Compliance Director
S. Markos, Manager, Design Engineering
J. Marooney, MPR Engineering Consultant
P. Martitz, Technical Support Superintendent
J. Melchionna, Engineering Services
R. Moore, System Engineering Branch Manager
D. Mora, Salem NDE Program Coordinator
G. Morrison, Mechanical Engineer
T. Mulholland, Shift Operations Manager
A. Ochoa, Senior Compliance Engineer
B. Ohmert, System Engineer
T. Oliveri, Salem Unit 1 and Unit 2, NDE Manager
J. O'Rourke, Regulatory Affairs
J. Owad, Design Engineering
M. Phillips, Regulatory Assurance
M. Pyle, Chemistry Manager
N. Ruvis, Westinghouse
B. Sebastian, Manager Fire Protection/Industrial Safety
J. Stairs, Manager Plant Engineering
C. Wend, Radiation Protection Manager
D. Yilgic, Lead Engineer Quality Control Chemistry

LIST OF ITEMS OPENED, CLOSED AND DISCUSSED

Open		
05000272/2016002-01	URI	Baffle-Former Bolts with Identified Anomalies (Section 1R08)
Open and Closed		
05000311/2016002-02	NCV	Failure to Follow Operability Determination Procedure for Unit 2 Baffle-Former Bolts (Section 1R15)
05000311/2016002-03	FIN	Inadequate Work Order Planning Results in Main Generator AVR STV Relay Trip (Section 4OA3.3)
Closed		
05000272:311/2015-008-01	URI	Inadequate Maintenance Rule System Performance Criteria Selection (Section 4OA5)
05000311/2016-001-00	LER	Auxiliary Feedwater Loop Response Time Exceeded Technical Specifications (Section 4OA3.1)
05000311/2016-002-00	LER	Automatic Reactor Trip Due to Main Turbine Trip (Section 4OA3.3)

LIST OF DOCUMENTS REVIEWED

* Indicates NRC-identified

Section 1R01: Adverse Weather Protection

Procedures
SC.OP-SO.500-0001, Trip-A-Unit Scheme Operation, Revision 10
OP-AA-108-107-1001, Electric System Emergency Operations and Electric Systems Operator Interface, Revision 4

Notifications
20731655* 20731657* 20731658* 20731659* 20731662 20731729*
20731735*

Section 1R04: Equipment Alignment

Procedures
SC.MD-ST.125-0003, Quarterly Inspection and Preventive Maintenance of Units 1, 2, & 3 125 Volt Station Batteries, Revision 30
S1.OP-ST.CAN-0007, Refueling Operations – Containment Closure, Revision 25
S2.OP-SO.SW-0005, Service Water System Operation, Revision 42
S2.OP-SO.ABV-0001, Auxiliary Building Ventilation System Operation, Revision 25
S2.OP-SO.SJ-00001, Preparation of the Safety Injection System for Operation, Revision 19
OP-SA-102-106, Salem Operations Master List of Timed Actions, Revision 0
OP-AA-108-103, Locked Equipment Program, Revision 4

Notifications
20702800 20707221 20724871 20729878* 20732182 20732551
20732785* 20732994* 20733091

Drawings
205337, Sheet 1, No. 2 Unit Auxiliary Building – Ventilation, Revision 43
205242, Sheet 1, No. 2 Unit Service Water Nuclear Area, Revision 81
205242, Sheet 2, No. 2 Unit Service Water Nuclear Area, Revision 76

Maintenance Orders/Work Orders
50180453 50182431 60125981 60129782

Section 1R05: Fire Protection

Procedures
FP-SA-2542, Pre-Fire Plan Unit 2 Spent Fuel/Component Cooling Heat Exchanger and Pump Area, Revision 0
FP-SA-2552, Pre-Fire Plan Unit 2 Boric Acid Evaporator Unit & Chemistry Area, Revision 0
FP-SA-2651, Pre-Fire Plan Unit 2 Service Water Intake Structure, Revision 0
FP-SA-2555, Pre-Fire Plan Unit 2 Diesel Generator Area, Revision 0
FP-SA-2556, Pre-Fire Plan Unit 2 Inner Piping Penetration Area & Chiller, Revision 0

Notifications

20723743	20730150*	20732820*	20732836*

Section 1R07: Heat Sink Performance

Notifications
20726947
20727041
20727041

Maintenance Orders/Work Orders
30255437

Section 1R08: In-service Inspection

NDE Procedures
Liquid Penetrant Examination Procedure, OU-AA-335-002, Revision 3
Nondestructive Examination Procedure, Manual Ultrasonic Examination of Vessel Nozzle Inner Radius Regions, Procedure Number 54-ISI-132-011, 1/27/2011
Nondestructive Examination Procedure, Ultrasonic Examination of Austenitic Piping Welds, Procedure Number 54-ISI-836-014, 8/21/2013
Areva NP Inc., Nondestructive Examination Procedure, Multi-Frequency Eddy Current Examination of Tubing, Procedure Number 54-ISI-400-021, 6/12/2013

Notifications

20682192	20694861	20697140	20697577	20697669	20699820
20699859	20699910	20704139	20707057	20707057	20707125
20712181	20712774	20713572	20713573	20713849	20713849
20714082	20716581	20720745	20722494	20724667	20725857
20726340	20726743				

Maintenance Orders/Work Orders
60114705
60123261
60126260

Evaluations

70178672	70178814	70178821	70179375	70183001	70185980

Self Assessments
Check-In Self-Assessment, Salem INPO PWR Materials Review, 7/30/2015

NDE Records
Salem Unit 1, Liquid Penetrant Report No. PT-16-002, 11-RHRHEX Vessel Support, 4/15/16 (Summary No.205170)
Salem Unit 1, Liquid Penetrant Report No. PT-16-001, Pipe Lugs 8-RH-2116-10PL-1 thru 4, 4/15/16 (Summary No. 263631)
Salem Unit 1, Liquid Penetrant Report No. PT-16-004, Pipe to Penetration IA, Component 12 SJ-2152-36PS-4, 4/19/16 (Summary No. 263904)

Salem Unit 1, Liquid Penetrant Report No. PT-16-003, Inlet Nozzle-to-Pump (11 Charging Pump), Component 6-CV-2111-14R1, 4/15/16 (Summary No. 220757)
Salem Unit 1, Liquid Penetrant Report No. PT-16-005, PIPE TO VALVE (11CS48) component ID: 8-CS-2114-60, 4/15/16 (Summary No. 356640)

Design Change Package
80092579, Salem Unit 1 – Steam Generator Bowl Drain Repair, SG 11, 12, 13, and 14 (removal of Alloy 600 and associated 82/182 weld material from each SG Channel Head (SGCH) bowl drain plugs
PSEG NUCLEAR VTD NUMBER: 900013(019), Title Stress Analysis of Tube-Tubesheet Weld AREVA RSG, 11/23/15; Calculation Summary Sheet, 7/25/2015.
PSEG Nuclear Work Order 70172201; Areva Reanalysis of Salem Steam Generator tube-to-tubesheet joint as a friction joint and to provide a revised SG stress analysis to PSEG for record purposes
WO #60123261, including weld history sheet; Replace SISJ - !SJ248 & 2SJ249
PSEG NUCLEAR LLC VTD NUMBER: AREVA 902739 (001); Salem Unit 1 SG Condition Monitoring for 1R22 AND Final Operational Assessment for Cycles 23 & 24; 8/8/13
Drawings: 02-9124528D, Salem Unit 1 Steam Generator Channel Head Drain Modification, Revision 001
Drawings: 1512E32, Salem REPLACEMENT Steam Generator General Layout; Salem Unit 1 Steam Generator Channel Head Drain Modification, Revision 1
Drawing 02-9124526B, Revision 001, Steam Generator Channel Head Drain Plug
Document No.: 51-9207624-000, Salem Unit 1 SG Condition Monitoring for 1R22 and Final Operational Assessment for Cycles 23 & 24

Other Documents
NRC Regulatory Issues Summary 2016-02, Design Basis Issues Related To Tube-To-Tubesheet Joints in Pressurized-Water Reactor Steam Generators, March 23, 2016
PSEG NUCLEAR LLC VTD Number: 9000(019); AREVA Stress Analysis of Tube-Tubesheet Weld-AREVA, Vendor Number 32-9235210-001

Section 1R11: Licensed Operator Requalification Program

Other Documents
SG-1624, Risk Management, SGFP Trip, SGTR, dated 05/21/16

Section 1R12: Maintenance Effectiveness

Procedures
ER-AA-310-1004, Maintenance Rule – Performance Monitoring, Revision 14

Notifications
20689987 20729117* 20730512* 20730513* 20731038* 20732228*

Drawings
265029, Circ Water Swgr Bldg. 125VDC DC Distribution System, Revision 5

Section 1R13: Maintenance Risk Assessments and Emergent Work Control

Procedures
OP-AA-108-116, Protected Equipment Program, Revision 12

Notifications

20723781	20724495	20725030*	20725036	20726192	20727564
20727565	20728242	20731749	20733122		

Maintenance Orders/Work Orders
60128649

Other Documents
ACE 20723873, 11 CFCU Low Speed Breaker Back-Flashed

Section 1R15: Operability Determinations and Functionality Assessments

Calculations, Analysis, Engineering Evaluations, and Specifications
MPR Associates Letter "Salem Service Water Discharge Header - Disposition of Degraded Joints", (0108-0471-0007, Rev 1), 6/3/2016
MPR Associates Letter, Salem PCCP Bell-and-Spigot Joint Degradation-Supplemental Information to (MPR-2650 Revision 0), 10/26/05
MPR Associates Letter, Salem Service Water Discharge Header - Disposition of Degraded Joints (0108-0471-0007, Rev 0), 4/29/2016
MPR Calculation 0108-0333-JEM-01, Structural Evaluation of Service Water Piping Thinned Joints, Revision 0
PSEG VTD 326511-001, "Structural Evaluation of Service Water Piping Thinned Joints"
PSEG VTD 326511-002, "Service Water"
PSEG VTD 326511-003, "Service Water WEKO Seal Structural Repair Relief Request RAI Response Technical Input"
PSEG VTD 326511-004, "Request for Use of Mechanical Repair System in Degraded Service Water Pipe Joints - Input for Response to NRG Request for Additional Information dated October 29, 2013"
S-C-SW-MEE-1975, Salem Units 1 & 2 Concrete Service Water Pipe Joints - Acceptance Criteria, Revision 0

Drawings, Wiring Diagrams, and Piping and Instrumentation Diagrams
205243, Sheet 1, Auxiliary Building Control Air, Revision 49
0108-0471-0007, Salem Service Water Discharge Header - Disposition of Degraded Joints, 4/29/2016

Evaluations

70097092	70097514	70103845	70131286	70144770

Notifications

20724198	20726264	20727538	20727590	20726001
20726320	20727126	20727354	20727430	20727678
20729040	20730485*	20727242	20727261	

Procedures
CC-AA-309-101, Engineering Technical Evaluation, Revision 10
OP-AA-108-115, Operability Determinations & Functionality Assessments, Revision 4
LS-AA-120, Issue Identification and Screening Process, Revision 13
LS-AA-125, Corrective Action Program, Revision 21
NO-AA-10, Quality Assurance Topical Report (QATR), Revision 84
S1.OP-PT.CA-0001, Emergency Control Air Compressor Functional Test, Revision 18
S1.OP-LR.CA-0005, Leak Rate Test 1CA920, Revision 1
SC.OP-LB.DF-0001, Diesel Fuel Oil Testing Program, Revision 3

Maintenance Orders/Work Orders
30265178 50140453 50154389 50154555 50158970 50172136
60115402

Miscellaneous
Inspection Manual Chapter 0326, Operability Determinations & Functionality Assessments for Conditions Adverse to Quality or Safety, dated December 3, 2015
Event Notification 51902, Anomalies Identified during Visual Inspection of Reactor Vessel Internals, dated May 3, 2016
70187161, Extent of Condition Review for Salem Unit 2 Susceptibility to Baffle Bolt Failure, Revision 0
70187161, Extent of Condition Review for Salem Unit 2 Susceptibility to Baffle Bolt Failure, Revision 1
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Section 1R19: Post-Maintenance Testing

Procedures
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20273570	20670175	20672463	20723478	20723652	20723765
20724185	20724217	20725095	20725111	20726481	20727534

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30205173	60120462	60128697	60129161

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70171681

Section 1R20: Refueling and Other Outage Activities

Procedures
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MA-AA-716-008-1010, Reactor Services Project FME Plan, Revision 2
S1.OP-IO.ZZ-0006, Hot Standby to Cold Shutdown, Revision 37
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Procedures
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Section 2RS1: Access Control to Radiologically Significant Areas

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RP-AA-460, Control for High and Very High Radiation Areas, Revision 17
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Radiation Protection Plant Radionuclide Evaluation
Corrective Action Documents (various Notifications)

Section 2RS2: Occupational ALARA Planning and Controls

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Outage Chemistry Control Plan
1R24 Hard Gamma Projection
Corrective Action Documents (various Notifications)

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

Procedures
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Procedures
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Corrective Action Documents (various notifications)

Section 2RS5: Radiation Monitoring Instrumentation

Procedures
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Other Documents
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EN-AA-170-500, Meteorological Monitoring System Calibration and Maintenance (Metrological Tower), Revision 1
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Instruction VGTSA-1.1.7, Collection of Vegetable, Vegetation and Fodder Crops, Revision 8
Instruction 1.1.9, Collection of Potable Water Samples, Revision 3
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Instruction AQUACOLL-1.1.10, Collection of Aquatic samples, Revision 11
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Instruction VEGECEN-0.3.2, Salem/Hope Creek Vegetable Garden Census, Revision 6

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<u>Section 4OA3: Follow-up of Events and Notices of Enforcement Discretion</u>

<u>Notifications</u>
20733919*

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
ASME	American Society of Mechanical Engineers
AVR	automatic voltage regulator
CAP	Corrective Action Program
CCE	common cause evaluation
CFCU	containment fan cooling unit
CFR	*Code of Federal Regulations*
CS	containment spray
DC	direct current
DCP	design change package
EC	eddy current
ECAC	emergency compressed air compressor
ECCS	Emergency Core Cooling System
ECT	eddy current testing
EDG	emergency diesel generator
EFPY	effective full power years
EPD	electronic personal dosimeter
EPRI	Electric Power Research Institute
ESFAS	engineered safety feature actuation system
FIN	finding
FOSAR	foreign object search and retrieval
GPI	Groundwater Protection Initiative
HRA	high radiation area
HSS	high safety significant systems
HX	heat exchanger
IMC	Inspection Manual Chapter
IOD	immediate operability determination
IR	inspection report
ISI	In-service inspection
IASCC	Irradiation Assisted Stress Corrosion Cracking
kV	kilovolt
LCO	limiting conditions for operation
LER	licensee event report
LHRA	locked high radiation area
LLRT	local leak rate test
LTS	Laboratory and Testing Services
MPFF	maintenance preventable functional failure(s)
MR	maintenance rule
MRC	Management Review Committee
NCV	non-cited violation
NDE	nondestructive examination
NEI	Nuclear Energy Institute

NOS	Nuclear Oversight
NOTF	notification(s)
NRC	Nuclear Regulatory Commission
NVLAP	National Voluntary Laboratory Accreditation Program
ODCM	Offsite Dose Calculation Manual
PC	performance criteria
PI	performance indicator(s)
PM	preventive maintenance
PRA	probabilistic risk assessment
PSEG	Public Service Enterprise Group Nuclear LLC
QHPI	Quick Human Performance Investigation
RCE	root cause evaluation
RCS	reactor coolant system
REMP	Radiological Environmental Monitoring Program
RFO	refueling outage
RG	regulatory guide
RHR	residual heat removal
RP	radiation protection
RTO	relay test order
RWP	radiation work permit(s)
SBO	station blackout
SDP	significance determination process
SF	spent fuel
SG	steam generator
SI	safety injection
SOC	Station Oversight Committee
SSC	structure, system, and component
SW	service water
TS	technical specification(s)
UFSAR	Updated Final Safety Analysis Report
URI	unresolved item
UT	ultrasonically testing
V/Hz	volt/hertz
VHRA	very high radiation areas
WGE	work group evaluation
WOs	work order(s)