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

February 8, 2018

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

SUBJECT: SALEM NUCLEAR GENERATING STATION, UNIT NOS. 1 AND 2 – INTEGRATED INSPECTION REPORT 05000272/2017004 AND 05000311/2017004

Dear Mr. Sena:

On December 31, 2017, the U.S. Nuclear Regulatory Commission (NRC) completed an inspection at Salem Nuclear Generating Stations (Salem), Units 1 and 2. On January 11, 2018, the NRC inspectors discussed the results of this inspection with Mr. Charles McFeaters, Salem Vice President, and other members of your staff. The results of this inspection are documented in the enclosed report.

NRC inspectors documented five findings of very low safety significance (Green) in this report. Four of these findings involved violations of NRC requirements. The NRC is treating these violations as non-cited violations (NCVs) consistent with Section 2.3.2.a of the Enforcement Policy. NRC inspectors documented one finding of very low safety significance (Green) in this report. The finding did not involve a violation of NRC requirements.

If you contest the violations or significance of these NCVs, 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; and the NRC Resident Inspector at Salem Nuclear Generating Station. In addition, if you disagree with a cross-cutting aspect assignment 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 U. S. Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington, DC, 20555-0001; with copies to the Regional Administrator, Region I, and the NRC Resident Inspector at Salem.

This letter, its enclosure, and your response (if any) will be made available for public inspection and copying at http://www.nrc.gov/reading-rm/adams.html and the NRC Public Document Room in accordance with 10 CFR 2.390, "Public Inspections, Exemptions, Requests for Withholding."

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 05000272/2017004 and 05000311/2017004
w/Attachment: Supplementary Information

cc w/encl: Distribution via ListServ

SUBJECT: SALEM NUCLEAR GENERATING STATION, UNIT NOS. 1 AND 2 – INTEGRATED INSPECTION REPORT 05000272/2017004 AND 05000311/2017004 DATED FEBRUARY 8, 2018

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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.	05000272/2017004 and 05000311/2017004
Licensee:	PSEG Nuclear LLC (PSEG)
Facility:	Salem Nuclear Generating Station, Units 1 and 2
Location:	Hancocks Bridge, NJ 08038
Dates:	October 01, 2017 through December 31, 2017
Inspectors:	P. Finney, Senior Resident Inspector A. Ziedonis, Resident Inspector J. Ayala, Reactor Inspector J. DeBoer, Emergency Preparedness Inspector T. Fish, Senior Operations Engineer N. Floyd, Reactor Engineer J. Furia, Senior Health Physicist
Approved By:	Fred L. Bower, III, Chief Reactor Projects Branch 3 Division of Reactor Projects

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SUMMARY

Inspection Report (IR) 05000272/2017004, 05000311/2017004; 10/01/2017 – 12/31/2017; Salem Nuclear Generating Station Units 1 and 2; In-Service Inspection Activities, Refueling and Other Outage Activities, Radiological Hazard Assessment and Exposure Controls, Problem Identification and Resolution.

This report covered a three-month period of inspection by resident inspectors and announced inspections performed by regional inspectors. The inspectors identified one NRC-identified finding and four self-revealing findings of very low safety significance (Green), four of which were non-cited violations (NCVs). The significance of most findings is indicated by their color (i.e., greater than Green, or Green, White, Yellow, Red) and determined using Inspection Manual Chapter (IMC) 0609, "Significance Determination Process (SDP)," dated April 29, 2015. Cross-cutting aspects are determined using IMC 0310, "Aspects Within Cross-Cutting Areas," dated December 4, 2014. All violations of NRC requirements are dispositioned in accordance with the NRC's Enforcement Policy, dated November 1, 2016. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG-1649, "Reactor Oversight Process," Revision 6.

Cornerstone: Mitigating Systems

- Green. A self-revealing Green non-cited violation (NCV) of Unit 1 Technical Specification (TS) 6.8.1, "Procedures and Programs," as described in Appendix 'A' of Regulatory Guide 1.33, Revision 2, was identified when PSEG performed service water (SW) pump strainer discharge valve maintenance without adequate procedural guidance. PSEG replaced the valve, entered the issue in their Corrective Action Program (CAP), and completed an equipment reliability evaluation (ERE). PSEG's additional, planned corrective actions (C/As) include a procedural revision to install valve pins in a flush, depressed condition with a weld-over, maintenance plan revisions to include the same guidance, and taper pin inspections on valves from PSEG's extent of condition review.

  The finding was more than minor since it was associated with the equipment performance attribute of the Mitigating Systems cornerstone and adversely affected its objective to ensure the availability of those systems relied upon to mitigate the consequences of an accident. Specifically, the inadequate procedural guidance resulted in 11 additional days of pump inoperability and unavailability, and 32 hours of 1 SW bay unavailability to complete repairs. The finding was evaluated using IMC 0609, Attachment 4, and Appendix A, Exhibit 2, dated June 9, 2012, and screened to Green since it was not a qualification or design deficiency, did not represent a loss of a system or function, and did not exceed its TS allowed outage time. The finding had a cross-cutting aspect in the area of Human Performance, Documentation, in that limited PSEG staff were aware of the expected 11SW3 configuration, and procedures had not been updated to reflect the required configuration. [H.7] (Section 4OA2.3)

- Green. A self-revealing Green Finding (FIN) was identified when PSEG did not fully evaluate operating experience in accordance with LS-AA-115, "Operating Experience Procedure," and MA-AA-716-210, "Performance Centered Maintenance (PCM) Process." Specifically, PSEG did not fully evaluate and address vendor recommendations for preventive maintenance (PM) to replace aluminum electrolytic capacitors in station inverters every 7 to 8 years. This resulted in a failure of the 1A vital instrument bus (VIB) inverter.

PSEG C/As include addressing the vendor recommendations, updating the capacitor replacement frequency to every 6 years, and evaluating capacitor model replacement.

This finding was more than minor because it was associated with the equipment performance attribute of the Mitigating Systems Cornerstone and adversely affected the cornerstone objective of ensuring the availability and reliability of systems that respond to initiating events to prevent undesirable consequences. The finding was evaluated using IMC 0609 Attachment 4 and Appendix A Exhibit 2, dated June 9, 2012, and screened to Green because it did not affect the design or qualification of a mitigating structure, system, and component (SSC), did not represent the loss of system and/or function, did not represent an actual loss of function of at least a single train for greater than its TS Allowed Outage Time, or two separate safety systems out-of-service for greater than its TS Allowed Outage Time, and did not represent an actual loss of function of one or more non-TS trains of equipment, designated as high safety-significance in accordance with the PSEG's Maintenance Rule Program (MRP), for greater than 24 hours. This finding was determined to have a cross-cutting aspect in the area of Problem Identification and Resolution, Operating Experience, in that, PSEG did not effectively evaluate and implement relevant internal and external operating experience in a timely manner. [P.5] (Section 4OA2.5)

Cornerstone: Barrier Integrity

- 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 XVI, "Corrective Action," when PSEG did not identify and correct a non-conformance with the Unit 1 containment thermal insulation system. The installed configuration did not provide a watertight seal between the containment liner and the insulation cover in conformance with the design specification. As a result, periodic SW leakage seeped behind the insulation and caused corrosion of the containment liner. PSEG's C/As included entering the issue into the CAP, repairing the portions of degraded liner, and planning to modify the top of the insulation panels to prevent water intrusion.

  The finding was more than minor because it was associated with the design control attribute of the Barrier Integrity cornerstone and adversely affected its objective to provide reasonable assurance that physical design barriers (i.e., containment) protect the public from radionuclide releases caused by accidents or events. The finding was evaluated using IMC 0609.04 and IMC 0609, Appendix A, Exhibit 3, dated June 9, 2012, and screened to Green because the finding did not represent an actual open pathway in the physical integrity of the reactor containment. This finding had a cross-cutting aspect of Problem Identification and Resolution (PI&R), Identification, because PSEG did not implement a CAP with a low threshold for identifying issues where individuals identify issues completely, accurately, and in a timely manner in accordance with the program. [P.1] (Section 1R08)

- Green. The inspectors documented a self-revealing, Green non-cited violation (NCV) of Unit 1 Technical Specification (TS) 6.8.1, "Procedures and Programs," for inadequate reactor vessel (RV) head removal procedures that led to the reactor coolant system (RCS) level lowering out of the procedural band during detensioning with lowered inventory and short time-to-boil conditions. PSEG's C/As included restoring level within operating bands, completing an apparent cause evaluation, revising associated procedures and entering this matter in their CAP as NOTF 20778011

  The issue was more than minor since it was associated with the RCS procedural quality attribute of the Barrier Integrity cornerstone and adversely affected its objective to provide

reasonable assurance that physical design barriers (i.e., fuel cladding and the RCS) protect the public from radionuclide releases caused by accidents or events. The finding was evaluated using IMC 0609, Appendix B, dated September 22, 2015, and screened to Green via IMC 0609 Appendix G, Attachment 1, dated May 9, 2014, based on not being a loss of level control, that is, an inadvertent loss of 2 feet of RCS inventory while not in mid-loop. The actual drop in level was less than one foot. The finding had a cross-cutting aspect in PI&R, Evaluation, in that PSEG did not thoroughly evaluate this issue to ensure that the resolution addressed the causes and extent of condition commensurate with its safety significance. Specifically, PSEG did not properly classify, prioritize, and evaluate the Unit 2 RCS level transient (April 2017) according to its safety significance so that the associated Unit 1 procedures were revised prior to their use during the same evolution in a subsequent RV detensioning (October 2017). [P.2] (Section 1R20)

Cornerstone: Occupational Radiation Safety

- Green. The inspectors documented a self-revealing, Green non-cited violation (NCV) of Technical Specification (TS) 6.12.1, when a worker entered a high radiation area with dose rates greater than 100 millirem per hour at 30 centimeters, without having been briefed on the area dose rates present before entry. PSEG C/As included restricting the worker's RCA access and entering the issue in their CAP as NOTF 20776693.

  The finding was more than minor because it was associated with the program and process (exposure control) attribute of the Occupational Radiation Safety Cornerstone and adversely affected its objective to ensure the adequate protection of the worker health and safety from exposure to radiation from radioactive material. The finding was evaluated using IMC 0609, Appendix C, dated August 19, 2008, and screened to Green because the finding was not an as low as reasonably achievable (ALARA) planning or work control issue, there was no overexposure or substantial potential for an overexposure, and the licensee's ability to assess dose was not comprised. The finding had a cross-cutting aspect in the area of Human Performance, Procedure Adherence, in that individuals follow processes, procedures, and work instructions. [H.8] (Section 2RS1)

REPORT DETAILS

Summary of Plant Status

Unit 1 began the inspection period at 100 percent reactor thermal power (RTP). The unit was shut down on October 12 for refueling outage (RFO) 1R25. A reactor startup was commenced on November 10 and the unit reached 100 percent RTP on November 15. On December 21, an unplanned power reduction to approximately 47 percent RTP was performed in response to lowering hydrogen pressure on the main generator. The hydrogen leak was identified and isolated, and power was returned to 100 percent RTP the following day. The unit remained at or near 100 percent for the remainder of the inspection period.

Unit 2 began the inspection period at 100 percent RTP where it generally remained and there were no additional plant status changes of regulatory significance during the inspection period.

On November 30, PSEG entered a Common Site (Salem and Hope Creek) Unusual Event (UE) Emergency Action Level (EAL) HU1.1, for a recorded 4.1 magnitude earthquake near Dover, Delaware (EN 53099). Operators implemented the abnormal operating procedures and continued to operate all three units onsite at 100 percent RTP with no equipment or structural issues identified related to the earthquake. PSEG exited the UE on November 30, 2017.

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, and Barrier Integrity

1R01 Adverse Weather Protection (71111.01 – 1 sample)

.1 Readiness for Seasonal Extreme Weather Conditions

a. Inspection Scope

The inspectors reviewed PSEG's readiness for the onset of seasonal cold temperatures. The review focused on the SW intake structure, SW accumulator buildings, fire protection pump house, and external piping and heating systems for the feedwater, primary, and refueling water storage tanks. The inspectors reviewed the Updated Final Safety Analysis Report (UFSAR), TSs, control room logs, and the CAP to determine what temperatures or other seasonal weather could challenge these systems, and to ensure PSEG personnel had adequately prepared for these challenges. The inspectors reviewed station procedures, including PSEG's seasonal weather preparation procedure and applicable operating procedures. The inspectors performed walkdowns of the selected systems to ensure station personnel identified issues that could challenge the operability of the systems during cold weather conditions. Documents reviewed for each section of this IR are listed in the Attachment.

b. Inspection Scope

No findings were identified.

1R04 Equipment Alignment

.1 Partial System Walkdown (71111.04Q – 2 samples)

a. Inspection Scope

The inspectors performed partial walkdowns of the following systems:

- Unit 1, Containment during irradiated fuel moves on October 18
- Unit 2, Chilled water and SW with 22 chiller out of service (OOS) on October 11

The inspectors selected these systems based on their risk-significance relative to the reactor safety cornerstones at the time they were inspected. The inspectors reviewed applicable operating procedures, system diagrams, the UFSAR, TSs, work orders (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 December 20, the inspectors performed a complete system walkdown of accessible portions of the Unit 1 and Unit 2 chilled water systems during flow testing in the 'C' configuration per TS 3.7.10c, to verify the existing equipment lineup was correct. The inspectors reviewed operating procedures, drawings, WOs, 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. For identified degradation the inspectors confirmed the degradation was appropriately managed by the applicable aging management program. Additionally, the inspectors reviewed a sample of related NOTFs 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 – 4 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 OOS, degraded, or inoperable fire protection equipment, as applicable, in accordance with procedures.

- Unit 1, Containment on November 8
- Unit 1, Spent fuel (SF) pool heat exchanger (HX) and component cooling water (CCW) HX area on November 10
- Unit 1, Mechanical penetration area on November 14
- Unit 2, Emergency diesel generator (EDG) areas on November 30

b. Findings

No findings were identified.

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

a. Inspection Scope

The inspectors reviewed the Unit 1, 11 CCW HX readiness and availability to perform its safety functions. The inspectors observed portions of the as-found inspection of the component cooling HX. The inspectors discussed the results of the most recent inspection with engineering staff and reviewed the results of the eddy current testing performed to measure the HX tube wall thickness. The inspectors verified that PSEG initiated appropriate C/As 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

From October 23 to November 1, 2017, the inspectors conducted an inspection and review of in-service inspection (ISI) activities in order to assess the effectiveness of PSEG's program for monitoring degradation of the RCS boundary, risk-significant piping boundaries, and the containment system boundaries during the Salem Unit 1 25th RFO (1R25).

Non-destructive Examination and Welding Activities (IP Section 02.01)

The inspectors observed a sample of in-process non-destructive examinations (NDE), reviewed completed documentation, and interviewed PSEG personnel to verify that the NDE activities performed as part of the fourth interval, second period, of the Salem Unit 1 ISI program were conducted in accordance with the requirements of the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code, Section XI, 2004 Edition with no Addenda. For augmented examinations, the inspectors verified that activities were performed in accordance with PSEG's augmented inspection program and procedures, and with any applicable industry guidance documents. The inspectors verified that indications and defects, if present, were dispositioned in accordance with the ASME Code or an NRC-approved alternative, and verified that relevant indications were compared to previous examinations to determine if any changes had occurred.

Activities included a review of ultrasonic testing (UT), radiography testing (RT), and visual testing (VT). The inspectors reviewed certifications of the NDE technicians performing the examinations and verified that the inspections were performed in accordance with qualified NDE procedures and industry guidance. For UT activities, the inspectors also verified the calibration of equipment used to perform the examinations. The inspectors verified that the test results were reviewed and evaluated by certified Level III NDE personnel as directed by PSEG procedures and that the parameters used in the test were in accordance with the limitations, precautions, and prerequisites specified in the test procedure.

ASME Code Required Examinations

- Direct observation of the automated phased array UT of the RV outlet nozzle to safe-end welds, #12 Hot Leg @ 338^{o} (29-RC-1120-1) and #14 Hot Leg @ 22^{o} (29-RC-1140-1).

- Direct observation of the manual UT of the residual heat removal pipe to elbow weld (14-RH-1111-10).

- Record review of the RT of the two field welds (4-AF-2114-2A and 4-AF-2114-3) associated with the 14AF23 valve replacement in the auxiliary feedwater (AFW) system.

Other Augmented, License Renewal or Industry Initiative Examinations

- Record review of the VT and UT of a sample of inaccessible containment liner plates on elevations 78' and 100' inside the containment building as part of an ongoing license renewal commitment. The containment liner plates were made accessible by temporarily removing sections of the overlying insulation panels.

Examination of Previous Indications

The inspectors did not review any previous indications because there were no relevant indications from the previous outage that required re-examination or evaluation for continued service at this time.

Welding on Pressure Boundary Systems

The inspectors reviewed the following pressure boundary risk-significant welding activities, including the associated NDE:

- One pipe-to-pipe weld (4-AF-2114-2A) and one pipe to elbow weld (4-AF-2114-3) as part of a repair/replacement activity in the AFW system. Specifically, the scope of the activity was to cut out and replace the 14AF23 valve due to the valve failing one of its required in-service tests (IST). The repair was performed under WO 60132668; and,

- Multiple weld overlays as part of a repair to the containment metal liner. Specifically, the scope of the activity was to restore the nominal wall thickness of several containment liner plates on elevation 100' that were identified as having localized corrosion due to historic leaks in the containment building. The repair was performed under WO 60131819.

The inspectors observed portions of the in-field welding and performed a documentation review of the remaining welding activities to verify that the welding, NDE, and final acceptance were performed in accordance with the ASME Code requirements. The inspectors reviewed the weld procedure specification to ensure it contained the required essential and supplemental essential weld variables, and that those variables were within the ranges demonstrated by the supporting qualification record. The inspectors also reviewed the weld records to determine if they were performed with the base and weld filler materials listed in the welding specification.

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

The inspectors reviewed the reactor pressure vessel upper head examinations, procedures, and records to verify that they were performed in accordance with requirements of 10 CFR 50.55a and ASME Code Case N-729-4, "Alternative Examination Requirements for PWR Reactor Vessel Upper Heads," to ensure the structural integrity of the RV head pressure boundary. The inspectors reviewed the post-examination documentation of the bare metal VT of the exterior surface of the RV upper head to verify that no boric acid leakage had been observed. The inspectors also verified that the required coverage for the surfaces had been achieved.

No ultrasonic weld examinations were performed during this RFO. The inspectors verified that the ultrasonic examinations were scheduled in accordance with the periodicity requirements of ASME Code Case N-729-4. Because the Salem Unit 1 RV upper head was replaced with nozzles and welds made of PWSCC-resistant materials, the ultrasonic examinations do not have to be performed every RFO.

Boric Acid Corrosion Control Inspection Activities (IP Section 02.03)

The inspectors reviewed Salem's boric acid corrosion control program as described in PSEG procedures and discussed the program requirements with the boric acid program owner. The inspectors performed independent walkdowns of various plant areas inside the containment building and reviewed photographic records of several identified boric acid leakage locations. The inspectors reviewed a sample of condition reports to verify that degraded or non-conforming conditions were identified properly within the CAP.

The inspectors reviewed two engineering evaluations (listed in the documents reviewed section) performed for boric acid found on piping and components to determine whether PSEG properly applied applicable corrosion rates to the affected components, and properly assessed the effects of corrosion-induced wastage on structural or pressure boundary integrity. The inspectors also reviewed the C/As planned and/or performed for those areas identified with evidence of boric acid leaks. Samples were selected based on actions for repair, component function, significance of leakage, and location where direct leakage or impingement on adjacent locations could cause degradation of safety system components.

Steam Generator Tube Inspection Activities (IP Section 02.04)

The inspectors directly observed a sample of the steam generator (S/G) eddy current tube examinations, which consisted of full length bobbin inspection of 100 percent of all active tubes in each of the four S/Gs; array probe inspection of the top-of-tubesheet of 100 percent of all active tubes in the 13 S/G and 50 percent of all active tubes in the other three S/Gs; and +Point probe inspection of any special interest tubes. The inspectors reviewed the results of the examinations to determine how well PSEG was able to predict future tube performance by comparing the results with the values predicted in the previous outage operational assessment.

The inspectors then evaluated the scope of eddy current testing to determine if areas of potential degradation were inspected, noting if areas known to represent eddy current challenges were included. The inspectors also compared the S/G tube eddy current examination scope and expansion criteria with TS requirements to determine whether PSEG was in compliance with these requirements.

The inspectors verified that the S/G tube examination screening criteria were in accordance with the Electric Power Research Institute (EPRI) Steam Generator Guidelines and that the examination technique specification sheets used for the exams were appropriate for the expected types of tube degradation. The inspectors remotely observed a Qualified Data Analyst's review of five S/G tubes, including the one tube (R2C91) identified as leaking, to determine that proper eddy current analysis techniques were applied.

The inspectors reviewed PSEG's actions to locate the source of S/G primary-to-secondary leakage in the 13 S/G that occurred over the operating cycle and determined that these actions, which included visual inspections of plugs and a secondary side

pressure test, were sufficient to identify the source of the leakage. The inspectors independently verified via video recording that the source of the leakage was tube R2C91 in the 13 S/G. The inspectors reviewed the in-situ screening criteria and test data to determine if the appropriate leaking tube had been properly identified for in-situ pressure testing. The inspectors reviewed the test procedure 03-6016219, "Field Procedure for In-Situ Pressure Testing RSG Tubes Using the Triplex Pump," and the associated test plan to verify the tube was tested in accordance with EPRI In-Situ Pressure Test Guidelines. The inspectors reviewed the test results to determine the test was completed as planned and to verify the tube integrity performance criteria were met. The inspectors verified that the leaking tube (R2C91) was repaired with a plug.

The inspectors observed a sample of the secondary side examinations and reviewed PSEG's C/As for loose parts (i.e., foreign material) in the secondary side of the 13 S/G. For foreign objects that were inaccessible, and not removed, the inspectors determined PSEG performed an engineering evaluation that considered the potential effects of object migration and tube fretting damage.

Identification and Resolution of Problems (IP Section 02.05)

The inspectors reviewed a sample of Salem Unit 1 C/A reports, which identified NDE indications, deficiencies, and other non-conforming conditions since the previous RFO and during the current outage. The inspectors verified that non-conforming conditions were properly identified, characterized, evaluated, and that C/As were identified and entered into the CAP for resolution.

b. Findings

Introduction. The inspectors identified a Green NCV of 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Action," when PSEG did not identify and correct a nonconformance with the Unit 1 containment thermal insulation system. Specifically, the installed configuration did not provide a watertight seal between the containment liner and the insulation cover in conformance with the design specification. As a result, periodic SW leakage seeped behind the insulation and caused corrosion of the containment liner.

Description. The design of the Salem Unit 1 containment structure includes a carbon steel liner, which forms a water and gas tight boundary to prevent radiological contamination from reaching the environment in the event of a reactor accident. From elevation 78' to 110' of the containment building interior, the liner is covered with 348 thermal insulation panels to limit the temperature rise in the steel liner during a postulated accident. Due to the design of the insulation panels, Section XI of the ASME Boiler and Pressure Vessel Code considers the liner as inaccessible for visual examination at these locations. PSEG made a license renewal commitment as part of an augmented inspection program to inspect a sample of these inaccessible liner locations every period during the ten-year ISI interval. PSEG completed the initial inspections behind 82 insulation panels during the 1R22, 1R23, and 1R24 RFOs.

During the 1R24 RFO in May 2016, PSEG identified heavy surface corrosion and pitting under the insulation panel on one liner plate and performed a UT to measure the remaining wall thickness. The thickness was determined to be below the minimum thickness allowed by the ASME Code and was repaired using a weld overlay to restore the degraded area to nominal thickness. PSEG staff performed an extent-of-condition review of liner degradation under WO 70187557 and found that, in the presence of

historical SW leakage, the configuration of the insulation system at this location allowed water to seep behind the insulation and caused liner corrosion. Specifically, the top of approximately 20 thermal insulation panels had gaps at the interface of the panel and the liner, where the vertical weld test channels penetrated the panels, and were not properly sealed. During the 1R25 RFO in October 2017, PSEG performed additional inspections on a sample of inaccessible liner plates as a result of the previous degraded liner location. Six new liner plate locations were identified to be degraded below the minimum thickness allowed by the ASME Code and required weld repair to restore the liner back to nominal wall thickness. The liner locations remained functional because the degraded thicknesses were above the minimum required by design.

The inspectors reviewed the design of the thermal insulation system in PSEG Detail Specification S-C-1972-DSP-6354, “Thermal Insulation of the Reactor Containment Liner Plate Units No. 1 and 2.” The specification stated “all insulation surfaces shall be sealed and impermeable to moisture with a suitable vapor barrier,” and “all lagging, flashing, slip joints, cover plates, etc., in exposed areas shall be designed to provide adequate protection against driving water from containment spray entering under or behind lagging.” The specification also included a drawing of the general arrangement of the insulation panel, including the top channel and sealant. The inspectors determined that the installed configuration of the Unit 1 thermal insulation system was not in conformance with its design requirements because the top channel/cover of multiple insulation panels contained large gaps that were unsealed. The inspectors noted that PSEG staff did not identify any as-built drawings or instructions for the installed configuration that accounted for this discrepancy. Although PSEG staff identified the presence of gaps in the tops of the panels, the staff did not identify or document in the CAP that the gaps and lack of sealant were a non-conformance with the thermal insulation design specification. The panels were reinstalled after the completion of liner inspections/repairs with the gaps still present. Upon questioning by the NRC inspectors, PSEG staff performed a technical evaluation to provide reasonable assurance that the containment liner insulation system would continue to perform its design function with the installed configuration during a postulated design basis accident. The inspectors reviewed the technical evaluation and concluded that the condition was a long-term degradation mechanism that had no immediate adverse impact to the containment liner or other mitigating systems. Also, PSEG had performed a pressurization test on the containment structure during the 1R24 RFO in May 2016, which demonstrated the leakage integrity of the liner pressure boundary. The inspectors determined that PSEG did not identify and correct the non-conformance during both the 1R24 and 1R25 RFOs. The inspectors noted that PSEG had a planned action after the most recent 1R25 outage (NOTF 20779679), to develop recommendations for a future modification to the panels. However, this action was a recommendation and not a C/A, which was inadequate to address resolution of the issue in accordance with the requirements of PSEG procedure LS-AA-125, “Correction Action Program.” PSEG captured this issue in their CAP as NOTFs 20782228 and 20782853.

The inspectors also reviewed NRC Finding 2001006-01, detailed in Inspection Report 05000272/2001006 (ML011720399), which documented defects on the containment thermal insulation system due to SW leaks. Specifically, over 200 fasteners (i.e., studs and nuts) that support the thermal insulation panels against the containment liner were found degraded or missing due to corrosion. The inspectors determined that this was a missed opportunity by PSEG staff to evaluate the effects of the water intrusion and to identify and correct the non-conformance with the insulation detail design specifications at that time.

Analysis. The inspectors determined that not identifying and correcting a non-conformance with the containment thermal insulation system detailed design specifications was a performance deficiency that was reasonably within PSEG's ability to foresee and correct. The installed configuration did not meet the thermal insulation design requirements to prevent moisture intrusion behind the panels and as a consequence, repeated SW leaks over time seeped behind the insulation and caused corrosion of the containment liner. This issue was more than minor because it is associated with the design control attribute of the Barrier Integrity cornerstone and adversely affected its objective to provide reasonable assurance that physical design barriers (i.e., containment) protect the public from radionuclide releases caused by accidents or events. Specifically, although functional, the containment liner was degraded below the wall thickness allowed by the ASME code, impacting its physical integrity, and required a weld repair to restore it to nominal design thickness. The finding was evaluated using IMC 0609.04 and IMC 0609, Appendix A, Exhibit 3, and screened to Green since the finding did not represent an actual open pathway in the physical integrity of the reactor containment.

This finding has a cross-cutting aspect in Problem Identification and Resolution, Identification, because PSEG did not implement a CAP with a low threshold for identifying issues where individuals identify issues completely, accurately, and in a timely manner in accordance with the program. Specifically, PSEG did not identify that a non-conforming condition existed between the design of the thermal insulation system and its installed configuration. (P.1)

Enforcement. Title 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Action," states, in part, that measures shall be established to assure that conditions adverse to quality, such as non-conformances are promptly identified and corrected. Detail Specification S-C-1972-DSP-6354, "Thermal Insulation of the Reactor Containment Liner Plate Units No. 1 and 2," requires all insulation surfaces shall be sealed and impermeable to moisture with a suitable vapor barrier, and all lagging, flashing, slip joints, cover plates, etc., in exposed areas shall be designed to provide adequate protection against driving water from containment spray entering under or behind lagging. Contrary to the above, from May 2016 until November 2017, PSEG did not identify and correct a non-conformance with the Unit 1 containment thermal insulation system. Specifically, the installed configuration of the thermal insulation system was nonconforming with the detailed design specification in that it was not properly covered and sealed to provide adequate protection against moisture and driving water. PSEG's C/As included entering the issue in their CAP (NOTFs 20782228 and 20782853) and developing plans to modify the insulation panels to prevent water intrusion. Because this violation was of very low safety significance and was entered into PSEG's CAP, this issue is being treated as an NCV consistent with Section 2.3.2.a of the Enforcement Policy. **(NCV 05000272/2017004-01, Non-conformance with the Containment Thermal Insulation System was not Identified and Corrected**)

1R11 Licensed Operator Requalification Program (71111.11Q – 3 samples)

.1 Quarterly Review of Licensed Operator Requalification Testing and Training

a. Inspection Scope

The inspectors observed licensed operator simulator training on November 28 and December 4, which included a stator water runback, loss of CCW, natural circulation, and a reactor coolant (RC) leak in the auxiliary building. The inspectors evaluated

operator performance during the simulated event and verified completion of risk significant operator actions, including the use of abnormal and emergency operating procedures. The inspectors assessed the clarity and effectiveness of communications, implementation of actions in response to alarms and degrading plant conditions, and the oversight and direction provided by the control room supervisor. The inspectors verified the accuracy and timeliness of the emergency classification made by the shift manager and the TS action statements entered by the shift technical advisor. Additionally, the inspectors assessed the ability of the crew and training staff to identify and document crew performance problems.

b. Findings

No findings were identified.

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

a. Inspection Scope

The inspectors observed operator performance to verify that procedure use, crew communications, and coordination of activities between work groups similarly met established expectations and standards. The inspectors observed infrequently performed test or evolution briefings, pre-shift briefings, and reactivity control briefings to verify that the briefings met established licensee criteria. The major activities observed included:

- Unit 1, 1R25 Reactor shutdown and cooldown on October 12
- Unit 1, 1R25 Mid-loop on November 4 and reactor startup on November 10

b. Findings

No findings were identified.

.3 Licensed Operator Requalification (71111.11A – 1 sample, 71111.11B – 1 sample)

a. Inspection Scope

The following inspection activities were performed using NUREG-1021, “Operator Licensing Examination Standards for Power Reactors,” Revision 11, and Inspection Procedure Attachment 71111.11, “Licensed Operator Requalification Program.”

Examination Results

The operating tests for the week of September 11, 2017, were reviewed for quality and performance.

On October 30, 2017, the results of the annual operating tests were reviewed to determine if pass/fail rates were consistent with the guidance of NUREG-1021 and NRC IMC 0609, Appendix I, “Operator Requalification Human Performance Significance Determination Process (SDP).” The review verified that the failure rate (individual or crew) did not exceed 20 percent.

- 1 of 71 operators failed at least one section of the Annual Exam. The overall individual failure rate was 1.41 percent.

- 1 of 17 crews failed the simulator test. The crew failure rate was 5.88 percent.

Written Examination Quality

The inspectors reviewed three written examinations previously administered during the August-October 2016 examination cycle for qualitative and quantitative attributes as specified in Appendix B of Attachment 71111.11.

Operating Test Quality

Six job performance measures (JPMs) and three scenarios were reviewed for qualitative and quantitative attributes as specified in Appendix C of Attachment 71111.11.

Licensee Administration of Operating Tests

Observations were made of the dynamic simulator exams and JPMs administered during the week of September 11, 2017. These observations included facility evaluations of crew and individual performance during the dynamic simulator exams and individual performance of JPMs.

Examination Security

The inspectors assessed whether facility staff properly safeguarded exam material. JPMs, scenarios, and written examinations were checked for excessive overlap of test items.

Remedial Training and Re-Examinations

The remediation plan for one crew dynamic simulator failure (from the 2017 annual operating exam) was reviewed to assess the effectiveness of the remedial training. Remediation for the individuals was processed in accordance with site procedures.

Conformance with Operator License Conditions

Medical records for four Senior Reactor Operator licenses and three reactor operator licenses were reviewed to assess conformance with license conditions. All records reviewed were satisfactory.

Proficiency watch standing records were reviewed for the first three quarters of 2017. All active licensed operators met the watch standing requirements to maintain an active license.

The reactivation plan for two licensed operators were reviewed to assess the effectiveness of the reactivation process. The reactivations were successfully processed in accordance with site procedures.

Records for the participation of licensed operators in the requalification program from January 2016 through August 2017 were reviewed. Records for the performance of

licensed operators on annual requalification operating test and biennial requalification written exams were reviewed.

Simulator Performance

Simulator performance and fidelity was reviewed for conformance to the reference plant control room. A sample of simulator deficiency reports was also reviewed to ensure facility staff addressed identified modeling problems. Simulator test documentation was also reviewed.

Problem Identification and Resolution

A review was conducted of recent operating history documentation found in inspection reports, the licensee's CAP, and the most recent NRC plant issues matrix (PIM). The inspectors also reviewed specific events from the PSEG's CAP which indicated possible training deficiencies, to verify that they had been appropriately addressed. The Senior Resident Inspector was also consulted for insights regarding licensed operators' performance. These reviews did not detect any operational events that were indicative of possible training deficiencies.

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 C/As to return these SSCs to (a)(2). Additionally, the inspectors ensured that PSEG staff was identifying and addressing common cause failures that occurred within and across MR system boundaries.

- Unit 1, Commercial grade dedication of auxiliary building ventilation belts and sheaves and inverter capacitors on October 2, Quality Control (QC)
- Unit 1, Charging system maintenance in response to low flow margin on November 1
- Unit 1, Vital Instrument Bus (VIB) failures on November 7

b. Findings

No findings were identified.

1R13 Maintenance Risk Assessments and Emergent Work Control (71111.13 – 2 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 1,13 S/G tube leak pressure test on October 26
- Unit 1, RCS vacuum fill with one channel of pressurizer overpressure protection system (POPS) OOS on November 5

b. Findings

No findings were identified.

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

a. Inspection Scope

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

- Unit 1, S/G pressure and temperature limits on October 24
- Unit 1, POPS following 'B' channel failure on November 6
- Unit 2, 2PR2 pressurizer power operated relief valve leakage on October 23
- Common, Motor operated valve wedge pin shear capability in response to 10 CFR Part 21 Event Notification (EN) 48797

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.

b. Findings

No findings were identified.

1R18 Plant Modifications (71111.18 – 1 sample)

Permanent Modifications

a. Inspection Scope

The inspectors evaluated a modification of Unit 1 EDG SW valve Moore controller replacements implemented by Engineering Change Package 80111212. The inspectors verified that the design bases, licensing bases, and performance capability of the affected systems were not degraded by the modification. In addition, the inspectors reviewed modification documents associated with the upgrade and design change. The inspectors also interviewed engineering and operations personnel.

b. Findings

No findings were identified.

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

a. Inspection Scope

The inspectors reviewed the post-maintenance tests for the maintenance activities listed below to verify that procedures and test activities 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 QC hold point were performed and checked, and that results adequately demonstrated restoration of the affected safety functions.

- Unit 1, ‘B’ 125 volts direct current (VDC) battery cell replacements on October 30
- Unit 1, ‘B’ VIB inverter following planned and corrective maintenance on November 1
- Unit 1, Containment liner weld repair on November 6
- Unit 1, ‘A’ in-core detector on November 20
- Unit 2, 21 containment fan cooling unit SW outlet valve failure to open on October 17

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 RFO (1R25), conducted October 12 through November 12. The inspectors reviewed PSEG’s development and implementation of outage plans and schedules to verify that risk, industry experience, previous site-specific problems, and defense-in-depth were considered. During the outage, the inspectors observed portions

of the shutdown and cooldown processes and monitored controls associated with the following outage activities:

- Configuration management, including maintenance of defense-in-depth, commensurate with the outage plan for the key safety functions and compliance with the applicable TSs when taking equipment OOS
- Implementation of clearance activities and confirmation that tags were properly hung and that equipment was appropriately configured to safely support the associated work or testing
- Installation and configuration of RC 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 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 RFO activities.

b. Findings

Introduction. Inspectors documented a self-revealing, Green NCV of Unit 1 TS 6.8.1, "Procedures and Programs," for inadequate RV head removal procedures that led to the RCS level lowering out of the procedural band during detensioning with lowered inventory and short time-to-boil conditions.

Description. During a daily CAP review, inspectors reviewed NOTF 20778011 that discussed a Unit 1 RCS level transient on October 16, 2017, while level was at lowered inventory. PSEG's SO.RC-0005 procedures consider the unit to be at lowered inventory when RCS level is less than that indicated via the pressurizer and when RCS level is below the RV flange (104 feet). During detensioning, RV level lowered from 103.0 to 102.1 feet. This was outside the procedural band of 102.7-103.3 feet as directed in S1.OP-SO.RC-0005, "Draining the RCS to >101' Elevation," Revision 42, for 8 minutes. PSEG recovered RCS level by raising charging flow and reducing letdown flow. During this transient, the RCS time-to-boil was 21 minutes at a level of 103 feet and the key safety function of shutdown cooling was in Yellow risk for the lowered inventory. The NOTF referenced a similar condition that had occurred on April 18, 2017, during a Unit 2 RV head detensioning, documented under NOTF 20762530.

The inspectors reviewed the Unit 2 NOTF from the April 2017 occurrence. This NOTF discussed that RCS level had dropped from 102.9 to 102.2 feet instantly. PSEG recovered RCS level approximately 34 minutes later. During this transient, the RCS time-to-boil was approximately 15 - 24 minutes at a level of 103 feet and the key safety function of shutdown cooling was in Yellow risk for the lowered inventory.

NOTF 20762530 also stated that operating experience suggested this was a common occurrence during the last segment of detensioning, but that the magnitude experienced historically is less than 0.5 feet and usually only a 0.1-0.2 foot momentary change. From this experience, PSEG had created two action items to enhance the OP-SO.RC-0005 procedures and the common Outage Services detensioning procedure to include a note to inform the control room to be observant of anticipated momentary RCS level anomalies when the last remaining pass on the final six RV studs are detensioned. PSEG intended for these action items to be in place for the Unit 1 RFO starting in October 2017, but established due dates were beyond this timeframe; therefore, these action items were incomplete at the time of the Unit 1 RCS level transient.

PSEG performed an apparent cause evaluation or NOTF 20778011 under order 70197060 and determined that the cause was inadequate guidance in the SO.RC-0005 procedure to prevent a level perturbation during draindown due to inadequate vent paths and lack of Volume Control Tank (VCT) parameters. The C/As included revision of the SO.RC-0005 procedures to include a note for operators advising them of potential level perturbations, controlling VCT pressure and temperature more closely, verification of vent function and opening additional vent paths during and after drain down, and expansion of the designated level band. Other actions included revision of the Outage Services procedure SC.MD-FR.FH-0012 to include a hold point to contact the control room prior to detensioning the last RV head bolt.

NRC IMC 0609 Appendix G, Attachment 1, identifies that the risk significance of many shutdown findings rely on the operators' ability to diagnose the problem and perform appropriate actions, and that the success of those actions is dependent in part on procedures, time, and ability to diagnose the problem. The inspectors used this information to inform their perspective on this issue and, consistent with PSEG's cause evaluation, determined that PSEG's Unit 1 procedures were inadequate and that this was within PSEG's ability to foresee and correct given the spring 2017 Unit 2 RCS level transient.

Finally, inspectors assessed the performance characteristics of this issue and considered the following aspects pertinent. First, the NOTF associated with the spring 2017 transient was not coded as a condition adverse to quality (CAQ) while the evaluation associated with the similar fall 2017 transient coded that transient as a CAQ. Secondly, the action items from the spring 2017 transient were not assigned due dates supportive of the scheduled Unit 1 detensioning. Finally, the spring 2017 transient was not evaluated for a cause despite the level transient being larger than PSEG operating experience suggested and recovery to the operating band taking over 30 minutes. These aspects were used in determining a cross-cutting aspect for the finding.

Analysis. Inadequate procedures for removal of the reactor head was a performance deficiency within PSEG's ability to foresee and correct. The issue was more than minor since it was associated with the RCS procedural quality attribute of the Barrier Integrity cornerstone and adversely affected its objective to provide reasonable assurance that physical design barriers protect the public from radionuclide releases caused by accidents or events. Specifically, RCS level perturbations occurred during two consecutive RFOs during reactor head detensioning while at lowered inventory that caused level to go low out of procedural bands. The finding was evaluated using IMC 0609, Appendix B, and screened to Green via IMC 0609, Appendix G, Attachment 1

based on not being a loss of level control, that is, an inadvertent loss of 2 feet of RCS inventory while not in mid-loop.

Inspectors determined that the finding had a cross-cutting aspect in Problem Identification and Resolution, Evaluation, in that licensee organizations thoroughly evaluate issues to ensure that resolutions address causes and extent of conditions commensurate with their safety significance. Specifically, PSEG did not properly classify, prioritize, and evaluate the Unit 2 RCS level transient (April 2017) according to its safety significance so that the associated Unit 1 procedures were revised prior to their use during the same evolution in a subsequent RV detensioning (October 2017). (P.2)

Enforcement. Technical Specification 6.8.1 “Procedures and Programs,” states, in part, that written procedures be established, implemented, and maintained covering the applicable procedures recommended in Appendix ‘A’ of Regulatory Guide (RG) 1.33, Revision 2, February 1978. The RG 1.33, Appendix A, Section 9.d lists procedures that could be categorized as either maintenance or operating procedures for certain activities and includes the removal of the reactor head as one of those procedures. Contrary to the above, from April 18 to October 16, 2017, PSEG’s RV head removal procedures for Salem were inadequately established such that when implemented, the RCS level lowered low out of the procedures’ established band during conditions of lowered inventory and short time-to-boil. PSEG’s C/As included restoring level within operating bands, completing an apparent cause evaluation, revising associated procedures and entering this in their CAP as NOTF 20778011. Because this violation was of very low safety significance and was entered into PSEG’s CAP, this issue is being treated as an NCV consistent with Section 2.3.2.a of the Enforcement Policy.
(NCV 05000272/2017004-02, Inadequate Reactor Vessel Head Removal Procedure)

1R22 Surveillance Testing (71111.22 – 3 samples)

a. Inspection Scope

The inspectors observed performance of surveillance tests and/or reviewed test data of selected risk-significant structures, systems, and components 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, 13 AFW IST on October 4
- Unit 1, S/G blowdown primary containment isolation valves (PCIV) on October 20
- Unit 1, ‘C’ 125 VDC capacity testing (routine surveillance) on October 28

b. Findings

No findings were identified.

Cornerstone: Emergency Preparedness

1EP4 Emergency Action Level and Emergency Plan Changes (IP 71114.04 – 1 Sample)

a. Inspection Scope

PSEG implemented various changes to the Salem EALs, Emergency Plan, and Implementing Procedures. PSEG had determined that, in accordance with 10 CFR 50.54(q)(3), any change made to the EALs, Emergency Plan, and its lower-tier implementing procedures, had not resulted in any reduction in effectiveness of the Plan, and that the revised Plan continued to meet the standards in 50.47(b) and the requirements of 10 CFR Part 50, Appendix E.

The inspectors performed an in-office review of all EAL and Emergency Plan changes submitted by PSEG as required by 10 CFR 50.54(q)(5), including the changes to lower-tier emergency plan implementing procedures, to evaluate for any potential reductions in effectiveness of the Emergency Plan. This review by the inspectors was not documented in an NRC Safety Evaluation Report and does not constitute formal NRC approval of the changes. Therefore, these changes remain subject to future NRC inspection in their entirety. The requirements in 10 CFR 50.54(q) were used as reference criteria. The specific documents reviewed during this inspection are listed in the Attachment.

b. Findings

No findings were identified.

2. RADIATION SAFETY

Cornerstones: Occupational and Public Radiation Safety

2RS1 Radiological Hazard Assessment and Exposure Controls (71124.01 - 4 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, Regulatory Guide 8.38, and the procedures required by TSs as criteria for determining compliance.

Inspection Planning

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

Instructions to Workers (1 sample)

The inspectors reviewed high radiation area (HRA) 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 (1 sample)

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. The inspectors selected several sealed sources from inventory records and assessed whether the sources were accounted for and were tested for loose surface contamination. The inspectors evaluated whether any recent transactions involving nationally tracked sources were reported in accordance with requirements.

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

The inspectors reviewed the procedures and controls for high radiation areas (HRAs), very high radiation areas (VHRAs), and radiological transient areas in the plant.

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

Introduction. The inspectors documented a self-revealing, Green non-cited violation (NCV) of Technical Specification (TS) 6.12.1, when a worker entered a high radiation area with dose rates greater than 100 millirem per hour at 30 centimeters, without having been briefed on the area dose rates present before entry.

Description. A PDO conducting a walk down of plant equipment on the 78' elevation of the Unit 1 mechanical penetration area on October 15, 2017, under the control of radiation work permit (RWP) 11, task 110 (Operation Activities), entered a posted HRA without having been briefed on radiological conditions in the area prior to entry that day. Shortly after entry, the PDO received a dose rate alarm, exited the RCA, and reported to the RP shift technician. The maximum dose rate measured by the worker's electronic dosimeter was 104 millirem per hour, and the alarm set point was 80 millirem per hour. The worker's total dose for the entry was measured at 0.4 millirem. On the previous day, the PDO had been authorized for entry to this area, and received a radiological briefing. The PDO incorrectly assumed that due to this previous briefing, he could re-enter the area without a radiological briefing on another day.

Unit 1 TS 6.12.1.e. requires that workers entering an area with dose rates in excess of 100 millirem per hour measured at 30 centimeters from the source of radiation be provided with a briefing that includes the dose rates in the work area. The worker was restricted from access to the RCA pending an interview with the Radiation Protection Manager. This issue was documented in the PSEG's CAP as NOTF 20776693.

Analysis. Not receiving a radiological briefing before entry into a posted HRA was a performance deficiency within the PSEG's ability to foresee and correct. The performance deficiency was more than minor because it was associated with the program and process (exposure control) attribute of the Occupational Radiation Safety Cornerstone and adversely affected its objective to ensure the adequate protection of the worker health and safety from exposure to radiation from radioactive material. The finding was evaluated using IMC 0609, Appendix C, and screened to Green because the finding was not an ALARA planning or work control issue, there was no overexposure or substantial potential for an overexposure, and the licensee's ability to assess dose was not comprised. The finding had a cross-cutting aspect in the area of Human Performance, Procedure Adherence, in that individuals follow processes, procedures, and work instructions. (H.8)

Enforcement. Technical Specification 6.12.1 implements the controls that shall be applied to HRAs. Specifically, TS 6.12.1.e requires, in part, that workers shall be briefed on the dose rates present in high radiation areas prior to entry. Contrary to the above, on October 15, 2017, a worker entered an HRA without having been briefed on the dose rates present. PSEG C/As included restricting the worker's RCA access and entering the issue in their CAP as NOTF 20776693. Because this violation was of very low safety significance was entered into the PSEG's CAP, this violation is being treated as an NCV consistent with Section 2.3.2.a of the Enforcement Policy. **(NCV 05000272/2017004-03, Worker Not Briefed on Dose Rates Before Entering a High Radiation Area)**

2RS2 Occupational ALARA Planning and Controls (71124.02 - 2 samples)

a. Inspection Scope

The inspectors assessed PSEG's performance with respect to maintaining occupational individual and collective radiation exposures ALARA. The inspectors used the requirements contained in 10 CFR Part 20, RGs 8.8 and 8.10, TSs, and procedures required by TSs as criteria for determining compliance.

Inspection Planning

The inspectors conducted a review of Salem's 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.

Implementation of ALARA and Radiological Work Control (1 sample)

The inspectors reviewed radiological work controls and ALARA practices during the observation of in-plant work activities. The inspectors verified use of shielding, contamination controls, airborne controls, RWP controls, and other work controls were consistent with ALARA plans. The inspectors ensured that work-in-progress reviews were performed in a timely manner and adjustments made to the ALARA estimates when appropriate. The inspectors reviewed the results achieved against the intended ALARA estimates to confirm adequate implementation and oversight of radiological work controls. The inspectors also verified that the ALARA staff was involved with emergent work activities and were revising both dose estimates and ALARA controls in the associated RWPs/ALARA Plans, as appropriate.

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.

2RS8 Radioactive Solid Waste Processing and Radioactive Material Handling, Storage, and Transportation (71124.08 - 6 samples)

a. Inspection Scope

The inspectors verified the effectiveness of PSEG's programs for processing, handling, storage, and transportation of radioactive material. The inspectors used the requirements of 49 CFR 170-177, 10 CFR Parts 20, 61, and 71, applicable industry standards, RGs, and procedures required by TSs as criteria for determining compliance.

Inspection Planning

The inspectors conducted an in-office review of the solid radioactive waste system description in the UFSAR, the process control program, and the recent radiological effluent release report for information on the types, amounts, and processing of radioactive waste disposed. The inspectors reviewed the scope of quality assurance audits performed for this area since the last inspection.

Radioactive Material Storage (1 sample)

The inspectors observed radioactive waste container storage areas and verified the postings and controls and that PSEG had established a process for monitoring the impact of long-term storage of the waste.

Radioactive Waste System Walkdown (1 sample)

The inspectors walked down the following:

- Accessible portions of liquid and solid radioactive waste processing systems to verify current system alignment and material condition
- Abandoned in place radioactive waste processing equipment to review the controls in place to ensure protection of personnel
- Changes made to the radioactive waste processing systems since the last inspection
- Processes for mixing and transferring radioactive waste resin and/or sludge discharges into shipping/disposal containers
- Current methods and procedures for dewatering waste

Waste Characterization and Classification (1 sample)

The inspectors identified radioactive waste streams and reviewed radiochemical sample analysis results to support radioactive waste characterization. The inspectors reviewed the use of scaling factors and calculations to account for difficult-to-measure radionuclides.

Shipment Preparation (1 sample)

The inspectors reviewed the records of shipment packaging, surveying, labeling, marking, placarding, vehicle checks, emergency instructions, disposal manifest, shipping papers provided to the driver, and PSEG verification of shipment readiness.

Shipping Records (1 sample)

The inspectors reviewed selected non-excepted package shipment records.

Problem Identification and Resolution (1 sample)

The inspectors assessed whether problems associated with radioactive waste processing, handling, storage, and transportation, 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)

.1 Mitigating Systems Performance Index (6 samples)

a. Inspection Scope

The inspectors reviewed PSEG's submittal of the Mitigating Systems Performance Index for the following systems for the period of October 1, 2016, through September 30, 2017.

- Common, Emergency AC power system (MS06)
- Common, High pressure injection system (MS07)
- Common, Cooling water system (MS10)

To determine the accuracy of the PI data reported during those periods, the inspectors used definitions and guidance contained in Nuclear Energy Institute (NEI) Document 99-02, "Regulatory Assessment Performance Indicator Guideline," Revision 7. The inspectors also reviewed PSEG's operator narrative logs, NOTFs, Mitigating Systems Performance Index derivation reports, event reports, and NRC integrated IRs to validate the accuracy of the submittals.

b. Findings

No findings were identified.

.2 Occupational Exposure Control Effectiveness (1 sample)

a. Inspection Scope

The inspectors reviewed licensee submittals for the occupational radiological occurrences PI for the first quarter 2017 through the fourth quarter 2017. The inspectors used PI definitions and guidance contained in NEI 99-02, Revision 7, to determine the accuracy of the PI data reported. The inspectors reviewed electronic personal dosimetry accumulated dose alarms, dose reports, and dose assignments for any intakes that occurred during the time period reviewed to determine if there were potentially unrecognized PI occurrences. The inspectors conducted walkdowns of various locked high radiation area and VHRA entrances to determine the adequacy of the controls in place for these areas.

b. Findings

No findings were identified.

.3 Radiological Effluent Technical Specification/Offsite Dose Calculation Manual Radiological Effluent Occurrences (1 sample)

a. Inspection Scope

The inspectors reviewed licensee submittals for the radiological effluent Technical Specification/Offsite Dose Calculation Manual (TS/ODCM) radiological effluent occurrences PI for the first quarter 2017 through the fourth quarter 2017. The inspectors used PI definitions and guidance contained in the NEI 99-02, Revision 7, to determine if the PI data was reported properly. The inspectors reviewed the public dose assessments for the PI for public radiation safety to determine if related data was accurately calculated and reported.

The inspectors reviewed the CAP database to identify any potential occurrences such as unmonitored, uncontrolled, or improperly calculated effluent releases that may have impacted offsite dose. The inspectors reviewed gaseous and liquid effluent summary data and the results of associated offsite dose calculations to determine if indicator results were accurately reported.

b. Findings

No findings were identified.

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

.1 Routine Review of Problem Identification and Resolution Activities

a. Inspection Scope

As required by Inspection Procedure 71152, “Problem Identification and Resolution,” the inspectors routinely reviewed issues during baseline inspection activities and plant status reviews to verify PSEG entered issues into their CAP at an appropriate threshold, gave adequate attention to timely C/As, 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 included repetitive or closely-related issues that may have been documented by PSEG outside of the CAP, such as trend reports, PIs, major equipment problem lists, system health reports, MR assessments, and maintenance or CAP backlogs. The inspectors also reviewed PSEG CAP database for the second through fourth quarters of 2017 to assess NOTFs written in various subject areas (equipment problems, human performance issues, etc.), as well as individual issues identified during the inspectors' daily condition report review (Section 4OA2.1). The inspectors reviewed the PSEG CAP trending data, conducted under LS-AA-125, to verify that PSEG personnel were appropriately evaluating and trending adverse conditions in accordance with applicable procedures.

b. Findings and Observations

No findings were identified.

The inspectors determined that PSEG personnel were appropriately identifying trends as demonstrated by the following examples and NOTFs:

- SW pump degraded differential pressures during ISTs that required additional monitoring (20773788)
- Pressurizer heater backup group breaker trips and blown fuses (20776099)
- Human performance standards (20774067)
- Combustible material control online as well as during RFOs (20779275, 20777851, 20783955)
- Improper coding of NOTFs when identified by external oversight (20775766)

Of particular note, the Management Review Committee (MRC) documented 20 trend NOTFs in 2017 as compared to 7 trend NOTFs in 2016. The inspectors determined this was indicative of an improved sensitivity and low threshold to potential trends.

Equipment Reliability Evaluations

The inspectors reviewed a number of EREs completed during the period. The EREs were added as a CAP evaluation method in September 2016 and are focused on analyzing contributing aspects to equipment failure mechanisms.

- A revised ERE template was introduced in the July 2017 timeframe. The new template has a screening question regarding whether the failure consequence is consistent with the maintenance strategy applied to the equipment. An affirmative response results in documenting the basis and exiting the investigation. Inspectors noted that, of 14 EREs completed with this new template, 11 were answered 'Yes.' In all of these cases, PSEG overrode the process and continued the investigation based on pursuit of improving equipment reliability, identifying C/As, addressing acceptable consequences, and/or the matter was associated with an unplanned limiting condition for operation (LCO). The inspectors sought to understand this initial ERE step and held discussions with station engineering staff on the matter. Of concern was the concept that PSEG staff could determine through the CAP process that an evaluation was required that would subsequently be screened out. Ultimately, the inspectors assessed that the behavior of overriding the process in the interest of improving equipment reliability and identifying C/As was positive in that, by performing the ERE, the station determined causal aspects of the associated failures, developed C/As, and gained valuable insights.

- An ERE incorrectly stated that three inverter failures that occurred in the last 3 years due to the same failure mechanism were not safety-related; however, the inspectors identified that two of the inverters that failed were indeed safety-related. The ERE was revised to reflect this information (NOTF 20776512).

The inspectors determined that the trends documented above were of minor safety significance in accordance with IMC 0612.

.3 Annual Sample: 11 Service Water Strainer Discharge Valve Failure

a. Inspection Scope

On July 30, PSEG attempted to complete an IST of the 11 SW pump as part of post-maintenance testing (PMT). Operators were unable to achieve the proper differential pressure using the 11 SW pump strainer discharge valve, 11SW3, and noted that the manual actuator operated with less-than-usual resistance. Initial PSEG troubleshooting revealed that the upper stem was likely separated from the disc; when the actuator was removed, the upper stem moved outward with it. The as-found valve condition was that both disk-to-stem pins on the actuator side of 11SW3 were not in place; one was completely missing while the other was half missing. The pin on the opposite side was intact. This condition resulted in the 11SW3 butterfly disc being free to rotate on the stem. The stem should have remained in place given it is pinned to the disc with three taper pins. PSEG continued to troubleshoot and documented the condition in NOTF 20771766 for challenges with collecting the IST data.

PSEG replaced the 11SW3 valve on August 9, conducted an 11 SW pump IST, and returned the train to operable status on August 11. PSEG documented a number of matters related to this issue in their CAP and performed an ERE under operation 70195274. Inspectors reviewed the associated NOTFs, the ERE, walked down the affected and similar components, interviewed station personnel, and observed station meetings that reviewed the ERE.

b. Findings and Observations

Introduction. The inspectors documented a self-revealing Green NCV of Unit 1 TS 6.8.1, "Procedures and Programs," as described in Appendix 'A' of Regulatory Guide 1.33, Revision 2, when PSEG performed SW pump strainer discharge valve maintenance without adequate procedural guidance. This resulted in eleven days of pump inoperability and unavailability, and 32 hours of 1 SW bay unavailability to complete repairs.

Description. On April 27, 2013, the safety-related 11 SW pump strainer discharge valve, 11SW3, was replaced under an internal inspection maintenance plan via WO 30208976. The replacement valve had been sent to PSEG's nuclear satellite maintenance organization, Central Maintenance Shop (CMS), to be refurbished using procedure SC.MD-PM.ZZ-0106, "Disassembly, Inspection and Assembly of Henry Pratt Butterfly Valves Mode N-2F11," Revision 7. Steps 5.5.23 and 24 of this procedure had steps to "initiate a Code Job Package" and "weld each taper pin at both ends" respectively.

Through their investigation and evaluation, PSEG determined that procedural guidance provided to CMS did not clearly specify that the taper pins were to be cut flush with the valve disk, have the ends depressed, and completely weld over them in order to prevent microbiological-induced corrosion. PSEG determined that this information was "tribal knowledge" among PSEG work groups without formal documentation. Secondly, the weld history record specified a "bridge tack" weld that would not satisfy the welding requirement.

On July 24, 2017, the 11 SW pump was tagged for planned maintenance. On July 30, 2017, PSEG attempted to complete an IST of the 11 SW pump as part of its PMT. Operators were unable to achieve the proper differential pressure using the 11SW3 and noted that the manual actuator operated with less-than-usual resistance. Initial PSEG troubleshooting revealed that the upper stem was likely separated from the disc. On August 9, PSEG removed the 1 SW bay from service for 31 hours to replace the 11SW3 valve under WO 60135986. PSEG replaced the valve, conducted an 11 SW pump IST, and returned the train to operable status on August 11. PSEG entered the as-found condition in their CAP as NOTF 20772939 and performed an ERE under order 70195274.

As-left pictures of the 11SW3 installed in 2013 revealed that the pins installed were left protruding and seam welded around the outside of the pins, leaving them susceptible to corrosive river water. Finally, the bill of materials for the 11SW3 included both Inconel and stainless steel (SS) taper pins. CMS had elected to install stainless steel pins in their repairs, a material that is more susceptible to the corrosive SW environment. PSEG had changed the pin material from SS to Inconel 625 in a May 2008 purchase order, PO 4500430091, with the valve manufacturer Pratt. PSEG captured this potential gap in PSEG and CMS repair plan relationships in NOTF 20775039. PSEG's additional, planned C/As include a procedural revision to install the pins in a flush, depressed condition with a weld-over, maintenance plan revisions to include the same guidance, and taper pin inspections of valves identified by PSEG's extent of condition review. The inspectors assessed that the conclusion from PSEG's ERE that inadequate procedural guidance for the 11SW3 valve was appropriate, and that this was within PSEG's ability to foresee and correct.

Analysis. Performance of the 11SW3 valve maintenance at CMS without adequate procedural guidance was a performance deficiency within PSEG's ability to foresee and

correct. The finding was more than minor since it was associated with the equipment performance attribute of the Mitigating Systems cornerstone, and adversely affected its objective to ensure the availability of those systems relied upon to mitigate the consequences of an accident. Specifically, the inadequate procedural guidance resulted in eleven additional days of pump inoperability and unavailability, and 32 hours of 1 SW bay unavailability to complete repairs. The finding was evaluated using IMC 0609 Attachment 4 and Appendix A, Exhibit 2, dated July 1, 2012, and screened to Green since it was not a qualification or design deficiency, did not represent a loss of system or function, and did not exceed its TS allowed outage time.

The finding had a cross-cutting aspect in the area of Human Performance, Documentation, in that the licensee creates and maintains complete, accurate, and up to date documentation (H.7). Specifically, limited PSEG staff were aware of the expected 11SW3 configuration, and procedures had not been updated to reflect the required configuration.

- Enforcement. Technical Specification 6.8.1, Procedures and Programs, states, in part, that written procedures shall be established, implemented, and maintained covering the applicable procedures recommended in Appendix ‘A’ of RG 1.33, Revision 2, February 1978. Regulatory Guide 1.33, Revision 2, Appendix A, Section 9, “Procedures for Performing Maintenance,” states, in part, that maintenance that can affect the performance of safety-related equipment should be properly pre-planned and performed in accordance with written procedures appropriate to the circumstances. Contrary to this, procedure SC.MD-PM.ZZ-106 was inadequately established to perform maintenance on the 11 SW 3 valve in August 2013 and resulted in 11 days of additional pump inoperability and unavailability, and 32 hours of 1 SW bay unavailability, to complete repairs in August 2017. This issue was captured in PSEG’s CAP as NOTFs 20771766, 20772939, and 20775039. PSEG replaced the valve, entered the issue in their Corrective Action Program (CAP), and completed an equipment reliability evaluation (ERE). PSEG’s additional, planned corrective actions (C/As) include a procedural revision to install valve pins in a flush, depressed condition with a weld-over, maintenance plan revisions to include the same guidance, and taper pin inspections on valves from PSEG’s extent of condition review. Because the finding was of very low safety significance and entered in PSEG’s CAP, this finding is being treated as an NCV consistent with Section 2.3.2.a of the Enforcement Policy. **(NCV 05000272/2017004-04, Inadequate Maintenance Procedure for a Service Water Pump Strainer Discharge Valve)**

Observations:

- Inspectors identified that the ERE did not include information pertinent to the issue after it was discussed during a Management Review Committee (MRC) review meeting. Specifically, during the presentation of the ERE to the MRC on September 20, 2017, it was verbally communicated that fully assembled Pratt valves were being supplied to PSEG with their pins welded over and that when PSEG was assembling these valves, the need to weld over the pins was “tribal knowledge” and was not formally documented. MRC approved the ERE as written and did not document this information. This inspector observation was documented in NOTF 20775740, and PSEG revised and re-presented the ERE to MRC.

- Inspectors observed that the maintenance procedure, SC.MD-PM.ZZ-0106, “Disassembly, Inspection, and Assembly of Henry Pratt Butterfly Valves Model N-2F11,”

did not include a step to install the disc pins, although it did include guidance on welding the pins. PSEG captured this observation in NOTF 20780544. PSEG had already established an action to revise the maintenance procedure to include specific guidance on cutting the pins flush with the disc, depressing them, and welding over them to prevent microbial-induced corrosion.

.4 Annual Sample:

a. Inspection Scope

The inspectors performed an in-depth review of PSEG's casual evaluations and C/As associated with NCV 05000272;311/2015004-04, Inadequate Post Maintenance Testing on Over-Temperature Delta-Temperature (OTDT) Channels; and Licensee Event Reports (LER) 05000272/2015-004-00 and 05000311/2015-001-00 which were associated with two separate Conditions Prohibited by Technical Specifications for One Channel of OTDT Inoperable. In both events, Salem experienced an equipment failure that was not detected during PMT, which rendered a single channel of the OTDT system inoperable.

The inspectors assessed PSEG's problem identification threshold, causal analysis, and adequacy of C/As to determine whether PSEG was appropriately identifying, characterizing, and correcting problems associated with these issues and whether the planned or completed C/As 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 associated documents, conducted interviews with station personnel, and completed walkdowns of various indication channels in the main control room to gain an understanding of the issue and associated C/As.

b. Findings and Observations

No findings were identified.

In response to the event described in LER 05000311/2015-001-00, PSEG performed Equipment Apparent Cause Evaluation (EQACE) 70173371 to evaluate the cause of an equipment failure that occurred during performance of the PM, and apparent cause evaluation (ACE) 70173374 to evaluate adequacy of the PMT activity that did not identify the equipment failure. PSEG's C/As included replacing the failed equipment, revising applicable PM plans to include additional PMT requirements, revising main control room operator log sheets to include additional channel check requirements, and revising 45 test procedures to incorporate additional PMT requirements. The inspectors noted that NRC PI&R biennial team inspection report 2017008, Section 4OA2.1.b.(3), identified that only 20 of the 45 procedures revisions were completed at the time of the PI&R team inspection in August of 2017, which was documented as a minor performance deficiency (PD), in NOTF 20773280, for untimely C/A. During this annual PI&R sample, the inspectors performed a follow-up inspection and noted PSEG had completed 44 of the 45 procedure revisions, with the remaining procedure on administrative hold so that it could not be performed until the revision was completed. The inspectors determined that PSEG's overall C/As for the event described in LER 05000311/2015-001-00 were adequate.

In response to the event described in LER 05000272/2015-004-00, PSEG performed troubleshooting due to an abnormal axial flux distribution (AFD) value that was identified approximately 2 days after planned corrective maintenance to replace a power range

nuclear instrument (PRNI) detector. PSEG corrected the condition by performing a current meter calibration, and documented in NOTF 20689386 that the PMT activity for the current meter replacement incorrectly assigned the performance of a functional test in lieu of the calibration procedure. PSEG subsequently determined this issue was reportable under 10 CFR 50.73, because it resulted in one channel of OTDT being inoperable due to the incorrect voltage being applied from the current meter to the isolation amplifier that supplies voltage to the OTDT channel. Additionally, PSEG performed work group evaluation (WGE) 70175956 to evaluate the cause of the inadequate PMT. The inspectors reviewed NOTF 20689386, as well as the WGE, and noted that PSEG did not identify a CAQ for this event, and did not assign any corrective actions. The inspectors noted the WGE had an associated action assigned under NOTF 20689386 to revise procedure MA-AA-716-012, "Post Maintenance Testing," to incorporate the applicable PMT requirements associated with PRNI maintenance activities. The inspectors noted that the action to revise MA-AA-716-012 was still open at the time of the inspection.

The inspectors reviewed the timing of the WGE completion with respect to completion of the reportability review, and noted the WGE was completed prior to PSEG's reportability determination that concluded the issue resulted in the inoperability of a safety-related OTDT channel. The inspectors determined that the CAQ was ultimately corrected when the current meter was satisfactorily calibrated in accordance with a corrective maintenance work order, which is permitted to correct a CAQ under LS-AA-125, "Corrective Action Program," Revision 18, step 4.4.5. The inspectors determined that the failure of PSEG to identify a CAQ for an issue that resulted in the inoperability of a safety-related function was a PD. The inspectors determined this PD was minor because the CAQ was promptly corrected via a corrective maintenance work order. PSEG captured the minor performance deficiency under NOTF 20785934. The inspectors determined that while the action to revise the PMT procedure under NOTF 20689386 had not been completed in a timely manner, this was not a performance deficiency because the assigned action was not a corrective action and was therefore not required to be completed. The inspectors also performed a CAP review and did not identify any additional equipment failures as a result of the delay in updating the PMT procedure. The inspectors characterized the incomplete action to revise the PMT procedure as an observation to PSEG, which was captured under NOTF 20785934.

.5 Annual Sample: Loss of 1A Vital Instrument Bus Inverter

a. Inspection Scope

The inspectors performed an in-depth review of PSEG's casual evaluations and C/As associated with Vital Instrument Bus (VIB) inverter challenges based on a number of latched and unlatched transfers on the Unit 1 1A VIB inverter, blown fuses, and related operating experience. Salem Unit 1 experienced unlatched and latched transfers on January 19, 2017, and January 26, 2017, respectively. The January 26 event also resulted in a tripped breaker, blown fuses, and a shorted logic power supply card due to a failed capacitor that leaked electrolyte onto the power supply, causing a short circuit and resulting in the failure of the VIB inverter.

The inspectors assessed PSEG's problem identification threshold, causal analysis, extent of condition reviews, and the prioritization and timeliness of C/As to determine whether PSEG was appropriately identifying, characterizing, and correcting problems associated with these issues and whether the planned or completed C/As 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 also reviewed associated documents, conducted interviews with engineering personnel, and completed field walkdowns to gain an understanding of the implemented and planned C/As associated with this issue.

b. Findings

Introduction. A self-revealing Green FIN was identified when PSEG did not fully evaluate operating experience in accordance with LS-AA-115, "Operating Experience Procedure," and MA-AA-716-210, "Performance Centered Maintenance (PCM) Process." Specifically, PSEG did not fully evaluate and address vendor recommendations for PMs to replace aluminum electrolytic capacitors in station inverters every 7 to 8 years. This resulted in a failure of the 1A vital instrument bus (VIB) inverter.

Description. On February 8, 2010, the inverter vendor issued a service bulletin, Cyberex Service Bulleting SB-032-UPS, "Component Reliability on Cyberex UPSs," and recommended replacing the C111 and C113 capacitor bank after 7 to 8 years. The C113 capacitors reduce the high ripple currents on the direct current (DC) bus generated by the switching action of the inverter bridge. The bulletin stated that if capacitors are not changed, high ripple current on the DC bus may cause premature degradation of the battery and components in the inverter bridge section, and may cause inverter failures during loading. This was a change from their previous recommendation of every 10 years and a change from the industry template frequency. PSEG reviewed the service bulletin, but did not incorporate the new vendor recommendations into the station PM program, keeping their previously-established replacement frequency of 9 years.

On January 26, 2017, the control room received an alarm for failure of the 1A VIB inverter. PSEG found the DC inverter breaker, CB101, tripped and subsequently entered a 24-hour shutdown action per TS 3.7.2.1.b. Visual inspection of the inverter identified that the C113 filter capacitor bank had released electrolyte material across the inverter onto the adjacent logic power supply card, causing the logic power supply card to short and blow a fuse. PSEG entered the loss of the Unit 1A VIB inverter into their CAP as NOTF 20753978 and performed an ACE under order 70192996 and an ERE under order 70191881.

PSEG identified inverters with similar failures of C113 capacitors prior to the January 26, 2017, event in their ERE. On December 23, 2013, the 2B RMS inverter tripped with the C101 breaker open and blown fuses. PSEG investigation identified that all 16 capacitors in the C113 capacitor bank failed testing. On February 12, 2015, a non-safety related emergency lighting inverter failed with the C101 breaker open and fuses blown. PSEG concluded that these symptoms pointed to a potential C113 capacitor issue. On February 29, 2016, the 2A RMS inverter tripped with the C101 breaker open and blown fuses. PSEG's investigation identified a leaking C113 capacitor. For the three prior events identified in the ERE, no analysis had been performed to identify the cause of the capacitor failures. The capacitors were replaced and the inverters were returned to service.

PSEG's ACE determined that there was a lack of technical rigor in evaluating operating experience to identify lessons learned from industry and transfer them into station processes to prevent similar events from occurring, and to enhance the reliability of the station inverters. Specifically, screening, evaluating, and acting on in-coming operating experience documents is required by LS-AA-115. The procedure requires a review of internal and external operating experience documents and to classify the level of review

required. Further, a site formal review for vendor technical notifications is required as described in Attachment 4 of the procedure. Procedure MA-AA-716-210, “Performance Centered Maintenance (PCM) Process,” Revision 6, required that the PCM templates process utilizes internal and external operating experience and use maintenance history, industry experience, vendor recommendations, and insurance requirements to develop recommended PM activities and frequencies.

The inspectors reviewed ACE 70192996 and ERE 70191881 and determined that PSEG took appropriate C/As; however, the 1A VIB inverter failure could have been prevented if PSEG had evaluated and properly addressed industry operating experience and vendor recommendations for filter capacitor replacement in their PCM templates. PSEG updated the PM frequency to replace the C113 capacitors every 6 years, and is evaluating a different capacitor that is less susceptible to high ripple current degradation.

Analysis. The inspectors determined that not fully evaluating operating experience in accordance with LS-AA-115 and MA-AA-716-210 was a performance deficiency. This finding was more than minor because it was associated with the equipment performance attribute of the Mitigating Systems Cornerstone and adversely affected the cornerstone objective of ensuring the availability and reliability of systems that respond to initiating events to prevent undesirable consequences. Specifically, PSEG did not fully evaluate and address vendor recommended changes to the capacitor replacement intervals, which resulted in the failure and unavailability of the 1A VIB inverter. The finding was evaluated using IMC 0609 Attachment 4 and Appendix A Exhibit 2, and screened to Green because it did not affect the design or qualification of a mitigating SSC, did not represent the loss of system and/or function, did not represent an actual loss of function of at least a single train for greater than its TS Allowed Outage Time, or two separate safety systems out-of-service for greater than its TS Allowed Outage Time, and did not represent an actual loss of function of one or more non-TS trains of equipment, designated as high safety-significance in accordance with the PSEG’s MRP, for greater than 24 hours.

This finding was determined to have a cross-cutting aspect in the area of PI&R, Operating Experience, in that, PSEG did not effectively evaluate and implement relevant internal and external operating experience in a timely manner. Specifically, in 2010 PSEG did not effectively evaluate and address vendor recommendations to replace the C113 aluminum electrolytic capacitors in station inverters every 7-8 years, and did not incorporate internal operating experience into the replacement interval with the C113 capacitor failures in 2013, 2015, and 2016. (P.5)

Enforcement. The finding did not involve enforcement action because the inspectors did not identify a violation of regulatory requirements associated with this finding. PSEG has taken C/As to address the vendor recommendations, updated the capacitor replacement frequency to every 6 years, and is evaluating capacitor model replacement. Because the issue did not involve a violation of regulatory requirements and had very low safety significance, it is identified as a finding. (**FIN 05000272/2017004-05, Inadequate Evaluation of Operating Experience for Vital Instrument Bus Inverter**)

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

.1 Plant Events

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 PSEG's follow-up actions related to the events to assure that PSEG implemented appropriate C/As commensurate with their safety significance.

- Common site declaration of a Notice of Unusual Event due to Seismic Event (ENS 53099) on November 30
- Unit 1 power reduction to 47 percent RTP in response to a main generator hydrogen leak on December 21

b. Findings

No findings were identified.

.2 (Closed) Licensee Event Report (LER) 05000311/2017-001-00, Emergency Diesel Generator Start Due to a Loss of Power to the 2C 4160 Volt Vital Bus

a. Inspection Scope

On April 14, 2017, while attempting to fast transfer the 2C 4 kV vital bus from 24 Station Power Transformer (SPT) to 23 SPT, the 24 SPT infeed breaker opened properly but the 23 SPT infeed breaker failed to close. This resulted in de-energization of the 2C 4kV vital bus and subsequent start and loading of the 2C EDG to power the bus. This event was reported by PSEG as required by 10 CFR 50.73(a)(2)(iv)(A) under ENS 52681. PSEG determined the cause was attributed to a large burr on the movable contact assembly internal to the 52/IS positive interlock switch. Inspectors reviewed the LER, the associated evaluation and C/As under order 70193583, evaluations and C/As related to breaker failures on the 1B and 2B EDGs in September 2015 and February 2016 respectively (70179878, 70184008), interviewed station staff, and walked down associated plant equipment. No findings or violations of NRC requirements were identified. This LER is closed.

b. Findings

No findings were identified.

4OA6 Meetings, Including Exit

On January 11, 2018, the inspectors presented the inspection results to Mr. Charles McFeaters, Salem Vice President, and other members of the PSEG staff. The inspectors verified that no proprietary information was retained by the inspectors or documented in this report. PSEG management acknowledged and did not dispute the findings.

ATTACHMENT: SUPPLEMENTARY INFORMATION

SUPPLEMENTARY INFORMATION

KEY POINTS OF CONTACT

Licensee Personnel
C. McFeaters, Site Vice President, Salem
P. Martino, Plant Manager, Salem
S. Barr, Emergency Preparedness Manager
T. Cachaza, Senior Regulatory Compliance Engineer
R. Chan, Operations Training Simulator Instructor
R. DeNight, Salem Engineering Director
S. Dennis, Training Corporate Functional Area Manager
P. Fabian, Steam Generator Program Owner
T. Giles, ISI Program Owner
M. Hassler, Radiation Protection Manager
T. MacEwen, Regulatory Compliance
P. Martitz, Radiological Engineering Manager
D. McCollum, Principal Nuclear Engineer
D. Mora, PSEG NDE Level III
W. Muffley, Operations Training Manager
T. Mulholland, Shift Operations Manager
L. Newsome, Shipper
M. Ochoa, System Engineer
J. Schmidt, Site Welding Engineer
R. White, Operations Training Simulator Instructor
W. Wikoff, Boric Acid Program Owner

LIST OF ITEMS OPENED, CLOSED AND DISCUSSED

Open and Closed

05000272/2017004-01	NCV	Non-conformance with the Containment Thermal Insulation System was not Identified and Corrected (Section 1R08)
05000272/2017004-02	NCV	Inadequate Reactor Vessel Head Removal (Section 1R20)
05000272/2017004-03	NCV	Worker Not Briefed on Dose Rates Before Entering a High Radiation Area (Section 2RS1)
05000272/2017004-04	NCV	Inadequate Maintenance Procedure for a Service Water Pump Strainer Discharge Valve (Section 4OA2.3)
05000272/2017004-05	FIN	Inadequate Evaluation of Operating Experience for Vital Instrument Bus Inverter (Section 4OA2.5)

Closed

05000311/2017001-00	LER	Emergency Diesel Generator Start Due to a Loss of Power to the 2C 4160 Volt Vital Bus (Section 4OA3.2)

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Section 1R01: Adverse Weather Protection

Procedures
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SC.OP-PT.ZZ-0002, Station Preparations for Seasonal Conditions, Revision 14
SH.FP-TI.FP-0001, Freeze Protection and Winter Readiness of Fire Protection Systems, Revision 5
WC-AA-107, Seasonal Readiness, Revision 14

Notifications
20776356
20783176*
20783213

Section 1R04: Equipment Alignment

Procedures
CY-AP-120-400, Closed Cooling Water Chemistry, Revision 4
S1.OP-SO.CH-0001, Chilled Water System Operation, Revisions 32 and 33
S1.OP-ST.CAN-0007, Refueling Operations – Containment Closure, Revision 25
S2.OP-SO.CH-0001, Chilled Water System Operation, Revision 35
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Notifications

20785300	20784828	20784400	20784263	20784264	20784257
20784284	20784188	20782774			

Work Orders

60132216	60132175	70197918	70184891

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Section 1R05: Fire Protection

Procedures
FP-SA-1547, Unit 1 Mechanical Penetration Area, Revision 0

Notifications

20777851*	20783519*	20780090	20780834	20779693	20780016
20779839	20781783	20780846			

Section 1R07: Heat Sink Performance

Procedures
ER-AA-340-1002, Service Water Heat Exchanger and Component Inspection Guidance, Revision 6
SC.MD-PM.CC-0002, Component Cooling Heat Exchangers 11, 21, and 22 Internal Inspection, Revision 15

Notifications
20778691

Work Orders
30298474 30313148

Section 1R08: In-service Inspection

Procedures
03-6016219, Field Procedure for In-Situ Pressure Testing RSG Tubes Using the Triplex Pump, Revision 011
54-ISI-413, Multi Frequency Eddy Current Two-Row Pancake Coil Array Probe Examination of the Inside Diameter Surfaces of Nozzle Welds and Weld Regions, Revision 001
54-ISI-835, Ultrasonic Examination of Ferritic Pipe Welds, Revision 015
54-ISI-836, PDI Generic Procedure for the Ultrasonic Examination of Austenitic Piping Welds PDI-UT-2, Revision 016
54-ISI-874, Automated Phase Array Ultrasonic Examination of Large Diameter Austenitic and Dissimilar Metal Piping Welds from the Inside Surface for Detection and Length Sizing, Revision 000
ER-AP-331, Boric Acid Corrosion Control (BACC) Program, Revision 7
ER-AP-331-1001, Boric Acid Corrosion Control (BACC) Inspection Locations, Implementation and Inspection Guidelines, Revision 8
ER-AP-331-1002, Boric Acid Corrosion Control Program Identification, Screening, and Evaluation, Revision 8
LS-AA-120, Issue Identification and Screening Process, Revision 16
LS-AA-125, Corrective Action Program, Revision 24
OU-AP-335-043, Bare Metal Visual Examination (VE) of Class 1 PWR Components, Revision 3

S1.OP-PT.GBD-0001, 13 Steam Generator Leak Detection, Revision 2
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Notifications

20778954	20779113	20779182	20779512	20779679	20779980*
20780021*	20780029*	20782228*			

Drawings
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Work Orders

50189666	60131819	60132668	70187557

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180-9278127-000, NDE Services Final Report, Dated October 2017
180-9278384-000, Salem 1R25 RPV Outlet Nozzle ID Piping Examination Report, Dated October 30, 2017
51-5041443, Site Validation of Eddy Current (ET) Examination Techniques for PSEG Nuclear Salem Unit 1, Dated October 21, 2017
51-8100201, Salem In-Situ Pressure Test Summary Report, Dated November 1, 2017
51-9257621, Salem Unit 1 Condition Monitoring for 1R24 and Final Operational Assessment for Cycles 25 and 26, Dated October 21, 2016
51-9275231, SG Degradation Assessment for Salem Unit 1 Refuel Outage 25 (1R25), Dated October 21, 2017
51-9279094, Salem Unit 1 Condition Monitoring at 1R25 and Preliminary Operational Assessment for Cycles 26 and 27, Dated November 3, 2017
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CISI-SC-LTP2, Containment Inservice Inspection Plan for Salem Generating Station Units 1 & 2 Second Interval, Revision 1
Eddy Current Testing Screenshots for Steam Generator 13 Tubes R2C91, R34C79, R36C78, R50C94, and R53C85, Dated October 31, 2017
ISI-S1-LTP4-PLAN-TOC, ISI Program Plan Fourth Ten Year Inspection Interval Salem Unit 1, Revision 4
LR-N16-0187, Salem Unit 1 Owner's Activity Report for S1RFO24, Dated October 11, 2016
RT Data Sheet for Weld 4-AF-2114-2A (Field Weld 4), Dated October 28, 2017
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Salem 1 In-Situ Pressure Testing Plan, Dated October 28, 2017
S-C-1972-DSP-6354, Detail Specification: Thermal Insulation of the Reactor Containment Liner Plate, Dated December 14, 1973
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UT Data Sheet for Weld 29-RC-1120-1 (Summary 050901), Dated October 30, 2017
UT Data Sheet for Weld 29-RC-1140-1 (Summary 047301), Dated October 30, 2017

UT Data Sheets for Containment Liner Panel No. 32, 35, 92, 93, 98, and 105 on el. 100', Dated October 19 to 25, 2017
UT-17-028, UT Data Sheet for Weld 14-RH-1111-10 (Summary 093200), Dated October 24, 2017
UT-17-030, UT Data Sheet for Weld 4-AF-2114-3 (Summary 219320), Dated October 28, 2017
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Vendor Technical Document (VTD) 322689, Westinghouse Model F SG Technical Manual, Revision 3
VTD 326592, Specification Drawing for Replacement Reactor Vessel Closure Head - Salem Unit 1, Revision 2
Weld History Records for WO 60131819 from Containment Liner Repair, Dated November 6, 2017
Weld History Records for WO 60132668 from 14AF23 Valve Replacement, Dated October 30, 2017
Weld Pictogram for WO 60132668 on Valve 14AF23, Dated October 23, 2017

Section 1R11: Licensed Operator Requalification Program

Procedures
2-EOP-TRIP-1, Reactor Trip or Safety Injection, Revision 32
2-EOP-TRIP-2, Reactor Trip Response, Revision 31
2017 LOR Annual Operating Exam Sample Plan
OP-AA-105-102, NRC Active License Maintenance
S2.OP-AB.CC-0001, Component Cooling Abnormality, Revision 16
S2.OP-AB.PZR-0001, Pressurizer Pressure Malfunction, Revision 18
TQ-AA-106, Licensed Operator Requalification Training Program

Notifications
20783422*
20783815*

Other Documents
S-ESG-1703, Simulator Training Scenario
2017 Annual ESG – 1710 2017 Annual ESG – 1711 2017 Annual ESG - 1712

Job Performance Measures
2017 Annual S-8 2017 Annual S-9 2017 Annual IP-5 2017 Annual IP-7
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Biennial Written Exams (Previously administered August-October 2016)
2016 Biennial Exam Alpha Shift 2016 Biennial Exam Charlie Shift
2016 Biennial Exam Echo Shift

Simulator Testing
OPA-01 Manual Reactor Trip 7/27/16
OPA-02 Simultaneous Trip of All Feed Pumps 7/22/16
OPA-09 Max Unisolable MS Leak 7/26/16
OPA-10 Slow Primary Depressurization
REF-50 U2 Loss of 2H Bus 2/25/2016
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SSS-01.02,03 Low Power Heat Balance/Stability 6/22/2016
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Section 1R12: Maintenance Effectiveness

Procedures
S1.OP-ST.SJ-0016, High Head Cold Leg Throttle Valve Flow Balance Verification, Revisions 28 and 29
SM-AA-300-1001, Procurement Activities and Responsibilities, Revision 12

Notifications

20779429*	20779701	20779741	20778659	20778659	20778845
20779495	20779008	20778882	20777057	20779426	20778883
20778943	20779099	20784184*			

Work Orders

60136298	60127315	80121263

Other Documents
Commercial Grade Dedication Evaluation DP-99-2259, Revision 0
ERE 70197539, 1B VIB inverter blown fuse
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QC-4349
QC-5752
QC-6921A

Section 1R13: Maintenance Risk Assessments and Emergent Work Control

Procedures
S1.IC-SC.RHR-0002, RC Level Indication for Midloop Operation, Revision 23
S1.OP-PT.GBD-0001, 13 Steam Generator Leak Detection, Revision 2
S1.OP-SO.RC-0002, Vacuum Refill of the RCS, Revision 25
S1.OP-SO.RC-0006, Draining The Reactor Coolant System Less Than 101 Foot Elevation With Fuel In The Vessel, Revision 33
WC-AA-105, Work Activity Risk Management, Revision 6

Notifications

20777714*	20779014	20779296	20783741*	20778713	20778041
20779674	20779230	20778107	20778105	20773362	20771549
20772193	20772590	20770026	20768829	20767273	20603850
20773588	20780721	20780927	20780721		

Work Orders

60135565	70195297	70152996	60136144	60119923

Other Documents

NRC Information Notice 2017-03: Anchor Darling Double Disc Gate Valve Wedge Pin and Stem-Disc Separation Failures

VTD 322689, Westinghouse PSNH Seabrook NPP Unit 2 Model F SG Technical Manual as Modified by FTI for PSEG Salem Unit 1

Section 1R15: Operability Determinations and Functionality Assessments

Procedures

S1.OP-PT.GBD-0001, 13 Steam Generator Leak Detection, Revision 2

S2.OP-ST.INST-0001, Instrumentation – Accident Monitoring, Revision 18

Notifications

20774896	20774897	20779014	20779296	20778846	20779759
20779828	20372484	20389927	20576019	20584221	

Work Orders

60135565	70195297	70197224

Other Documents

ACM 17-009 (70197184), 2PR2 PORV Tailpipe Elevated Temperature

OTDM S-17-008, RCS Pressurizer PORV S2RC-2PR2 Seat Leakage

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Section 1R18: Plant Modifications

Notifications

20776840	20779588

Work Orders

30304916	60118706	60118707	80111212

Other Documents

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Section 1R19: Post-Maintenance Testing

Procedures

SC.MD-ST.125-0006, 125 Volt Station Batteries 18 Month Service Test using BCT-2000 with Windows Software and Associated Surveillance Testing, Revisions 3 and 4

MA-AA-716-012, Post-Maintenance Testing, Revision 20

SC.MD-PM.115-0001, 10/12 KVA Vital Instrument Bus Inverter Preventive Maintenance, Revision 15

SC.MD-CM.115-0001, 10/12 KVA Uninterruptible Power Supply Troubleshooting and Repair, Revision 18

Notifications

20480381	20487093	20487275	20778924	20779078	20779460
20779525	20779565	20779660	20779750	20779754	20780231
20780870	20780950	20776482	20753229	20731835	20731794
20765261	20776678	20777968	20783169	20782226	20780756
20781390	20782102	20782103	20782130	20782129	20780767
20780737	20780492	20783155	20782126	20782127	20781817
20782125	20782123	20782128	20782445	20744388	20782228
20779679	20780921	20779113	20780979	20780921	20780961

Drawings
204463, Unit 1 Reactor Containment Plan Elevation 78' and 81', Sheet 1, Revision 27
42472, Flux Mapping Miniature, Detector Insertion, Sheet 5, Revision B

Work Orders

30255201	30277085	50185624	60136572	60136555	601232479
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6S0-1800, Temperature of Concrete Containment Wall during DBA LOCA, Revision 1
6S0-1913, Evaluation of Containment Structure for Local Cut-Outs in Liner Insulation, Revision 0
6S1-2047, Qualification of Degraded Insulation Stud Bolts, Revision 0
PSEG Detail Specification 72-6354, Thermal Insulation of the Reactor Containment Liner Plate Units 1 and 2, Dated December 14, 1973
S-1-CAN-SEE-1519, SGS Containment, Liner Insulation Studs, 1RF14, Revision 0
S-C-RHR-MDC-2039, Debris Generation due to LOCA within Containment for Resolution of GSI-191, Revision 0
VTD 902203, MPR Calculation 0109-0394-01, Salem Containment Liner Stud Evaluation, Revision 1

Section 1R20: Refueling and Other Outage Activities

Procedures
SC.RE-ST.ZZ-0013, Initial Criticality and Testing Advanced Digital Reactivity Computer, Revision 22
SC.MD-TI.FH-0022, Manual Operation of the Manipulator Crane, Revision 0
S1.OP-AB.CONT-0001, Containment Closure, Revision 13
S1.OP-IO.ZZ-0003, Hot Standby to Minimum Load, Revision 38
S1.OP-IO.ZZ-0005, Minimum Load to Hot Standby, Revision 23
S1.OP-IO.ZZ-0006, Hot Standby to Cold Shutdown, Revision 39
S1.OP-IO.ZZ-0103, Hot Standby to Minimum Load Administrative Requirements, Revision 9
S1.OP-ST.SJ-001, Emergency Core Cooling ECCS Subsystems – Containment Sump – Modes 5-6, Revision 7
SC.OP-DL.ZZ-0011, Reactor Coolant System Heatup/Cooldown Log, Revision 9
SC.RE-RA.ZZ-0002, Inverse Count Rate Ratio During Reactor Startup, Revision 12

Notifications

20778031*	20778291*	20778713	20780450*	20780997*	20781722*
20781734*	20781778*	20781843*	20784184*	20785144*	20751564
20780507	20778592	20778728	20778697	20778852	20781942
20776716	20782137	20780096	20781737	20781736	20781131
20780689	20780745	20779802	20779593	20779766	20779477
20779471	20779473	20779474	20779475	20778039	20778879
20778778	20778699	20777787	20778647	20776693	20778078
20777979	20778066	20778047	20785603*		

Work Orders
60131819-0001-0050

Other Documents
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Shutdown Safety Evaluation for 1R25
S-C-SF-MDC-1810, Decay Heat-up Rates and Curves for Spent Fuel Pool, Revision 14

Section 1R22: Surveillance Testing

Procedures
S1.OP-ST.AF-0003, Inservice Testing – 13 Auxiliary Feedwater Pump, Revision 46
S1.OP-LR.GB-0001, Local Leak Rate Test 11GB4, Revision 0
S1.OP-LR.GB-0002, Local Leak Rate Test 12GB4, Revision 0
S1.OP-LR.GB-0003, Local Leak Rate Test 13GB4, Revision 0
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Notifications

20776359*	20776642*	20777847*	20778226*	20780790*	20784403*
20780868	20788547	20778911	20779226	20778582	20778004
20777982					

Work Orders

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Letter from C&D Technologies to PSEG Nuclear Re: 1C 125V Battery Test Failure, Dated October 16, 2017

Section 1EP4: Emergency Action Level and Emergency Plan Changes

Procedures
NC.EP-FT.ZZ-0009, Emergency Operations Facility Ventilation System Testing, Revision 0

Section 2RS1: Access Control to Radiologically Significant Areas

Notifications

20767793	20780008	20781944

Miscellaneous
RWP 11, 1R25 Aux, FHB, Pen and SRW Activities
RWP 14, 1R25 Containment Activities

Section 2RS2: Occupational ALARA Planning and Controls

Notifications
20782797 20783058

Miscellaneous
ALARA Plan 31, 1R25 Aux, FHB, Pen and SRW Activities

Section 2RS8: Radioactive Solid Waste Processing and Radioactive Material Handling, Storage, and Transportation

Procedures
RP-AA-600-1006, shipment of Category 1 Quantities of Radioactive material or Waste (Category 1 RAM-AC), Revision 8
RP-AA-610, Surveying Radioactive material Shipments, Revision 9
RP-AA-602, Packaging of Radioactive Material Shipments, Revision 16
RP-AA-602-1001, Packaging of Radioactive Material/Waste Shipments, Revision 9
RP-AA-605, 10CFR61 Program, Revision 1
RW-AA-605-1001, Evaluation of 10CFR61 Sample Results, Revision 1
RW-AA-100, Process Control Program for Radioactive Wastes, Revision 10

Notifications
20727015 20727731 20747198 20776039

Assurance of Quality
Audit NOSA-SLM-17-08, Radiation Protection Audit Report

10CFR61 Scaling Factors
Teledyne Brown Engineering Reports of Analysis for: Dry Active Waste; Liquid Waste Processing Resin; Spent Resin Storage Tank

Training
EnergySolutions Load Securing for Radioactive material Training
EnergySolutions Radioactive Waste Packaging, Transportation and Disposal Training
WMG RC-102 Use of WMG Programs and Regulatory Interfaces
EnergySolutions Air Transport of Radioactive Materials (IATA/DOT) Training
Salem/Hope Creek Lesson Plan NRP9902RMATC-04, NRC Bulletin 79-19 and 49CFR 172 Subpart H Required Periodic Training

Shipments
16-57 16-76 16-79 16-97 16-113

Section 4OA1: Performance Indicator Verification

Notifications
20784515*

Other Documents
Units 1 and 2 Unavailability and Unreliability Indices for MS06, MS07, and MS10

Section 4OA2: Problem Identification and Resolution

Procedures
LS-AA-125-1001, Cause Analysis, Revision 14
LS-AA-125-1003, Apparent Cause Evaluation Manual, Revision 14
LS-AA-120, Issue Identification and Screening Process, Revision 14
LS-AA-120, Issue Identification and Screening Process, Revision 15
LS-AA-125, Corrective Action Program, Revision 17
LS-AA-125, Corrective Action Program, Revision 18
LS-AA-125, Corrective Action Program, Revision 21
LS-AA-125, Corrective Action Program, Revision 23
LS-AA-115, Operating Experience Program, Revision 11
LS-AA-115, Manual for Processing OE6 Documents, Revision 0
LS-AA-115-1006, Operating Experience Program, Revision 15
MA-AA-716-004, Complex Trouble Shooting, Revision 14
MA-AA-716-012, Post Maintenance Testing, Revision 20
MA-AA-716-210, Performance Centered Maintenance (PCM) Process, Revision 3
NC.NA-AP.ZZ-0054(Q), Operating Experience (OE) Program, Revision 6
PIA-036, Equipment Reliability Evaluation, Revision 1
PIA-035, Cause Analysis Manual, Revision 1
S1.OP-AR.ZZ-0002(Q), Overhead Annunciator Window B, Revision 29
S1.OP-SO.115-0011(Q), 1A Vital Instrument Bus UPS System Operation, Revision 15
SC.MD-CM.115-0001(Q), 10/12 KVA Vital Instrument Bus Parts Replacement, Revision 2

Notifications

20725553	20753773	20753978	20754004	20759627	20760233
20768430	20770152	20776360*	20776455*	20776512*	20776512*
20776630*	20777665*	20777810*	20778652*	20778666*	20779094*
20779145*	20780892*	20781909*	20781997*	20782157*	20782641*
20782771*	20783119*	20783245*	20783441*	20783942*	20780583*
20780571*	20780572*	20780573*	20784445*	20784607*	20784966*
20784967*	20783810*	20783811*	20777818	20723437	20775023
20777008	20782030	20782221	20782651	20689386	20741534
20724221					

Drawings
309945, 10 KVA Vital Bus UPS, Revision 1
311223, Inverter Wiring Model 120/18.75IB1, Revision 2
601837, Units 1 and 2 T avg Control and Protection Interconnections, Revision 5

Work Orders

30156600	30242880	30244001	50198304	60133303	60133392
60135986	70195274	70196994	60135790	30315917	70173371
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Miscellaneous
70192996, ACE – Missed opportunity in Operating Experience Review
70191881, Equipment Reliability Evaluation, Dated March 29, 2017
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VTD 127779, Service Water System Flanged Butterfly Valves, Revision 3
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LER 05000311/2015-001-00, Condition Prohibited by Technical Specifications for One Channel of Over-Temperature Delta-T Inoperable
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Maintenance Plan S1400196
Maintenance Plan S2405128
ACE 70173371, 24NM306 Isolator Found Low
EQACE 70173374, Time of Discovery of Failed 24NM306
WGE 70175956, Incorrect PMT/RT Assigned to Corrective Maintenance Work

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

Procedures
EP-SA-111-107, Salem Generating Station, Section H – Hazards and Other Conditions Affecting Plant Safety, H1 – Natural and Destructive Phenomena – Earthquake, Revision 1
S1.OP-AR.ZZ-0008, Overhead Alarm Response H-33: H2 Pressure Hi or Lo, Revision 37
S1.OP-PT.GEN-0003, Main Generator Stator Temperatures, Revision 12
SC-IC.PT.INS-0001, Peak Recording Accelograph, Revision 4
SC.IC-PT.INS-0006, Seismic System Field Device Calibration Triaxial Time – History Accelerometers, Revision 5
SC.OP-AB.ZZ-0004, Earthquake, Revision 2

Notifications

20782593	20782595	20782848	20782847	20782849*	20782591
20782944*	20782941*	20780548*	20783044	20783119*	20780576*
20782615	20785560	20785373*	20784919	20785051	20785142
20784879	20785143	20784530	20784260	20784527	20784055
20784056					

Drawings
205220, Units 1 and 2 Hydrogen and Carbon Dioxide

Work Orders

30294982	60137255

Other Documents

A-5-500-EEE-1686, Attachment 1, Curve 2S1: Salem 1 Three Unit Operation: All Transmission Facilities In Service, Revision 11

GE Hitachi SC 16-03 R0, 10 CFR Part 21 Communication, Failure of CR2940U310 Normally Open Switch, Dated May 12, 2016

LIST OF ACRONYMS

10 CFR	Title 10 of the *Code of Federal Regulations*
ACE	apparent cause evaluation
ADAMS	Agencywide Documents Access and Management System
AFD	axial flux distribution
AFW	auxiliary feedwater
ALARA	as low as reasonably achievable
ASME	American Society of Mechanical Engineers
C/A	corrective action(s)
CAP	corrective action program
CAQ	condition adverse to quality
CCW	component cooling water
CFR	*Code of Federal Regulations*
CMS	Central Maintenance Shop
DC	direct current
EAL	Emergency Action Level(s)
EDG	emergency diesel generator(s)
EN	event notification
EPRI	Electric Power Research Institute
EQACE	Equipment Apparent Cause Evaluation
ERE	equipment reliability evaluation
FIN	finding
HRA	high radiation area
HX	heat exchanger
IMC	inspection manual chapter
IR	inspection report(s)
ISI	in-service inspection
IST	in-service test
JPM	job performance measures
LCO	limiting condition of operation
LER	licensee event report
MR	maintenance rule
MRC	Management Review Committee
MRP	Maintenance Rule Program
NCV	non-cited violation
NDE	non-destructive examination
NEI	Nuclear Energy Institute
NOTF	notification(s)
NRC	Nuclear Regulatory Commission
OOS	out of service
OTDT	over-temperature delta-temperature
PCIV	primary containment isolation valve(s)
PCM	performance centered maintenance
PD	performance deficiency

PDO	primary duty operator
PI	performance indicator(s)
PIM	plant issues matrix
PI&R	problem identification and resolution
PM	preventive maintenance
PMT	post-maintenance testing
POPS	pressurizer overpressure protection system
PRNI	power range nuclear instrument
PSEG	Public Service Enterprise Group Nuclear LLC
QC	Quality Control
RC	reactor coolant
RCA	radiologically controlled area
RCS	reactor coolant system
RFO	refueling outage
RG	regulatory guide
RP	radiation protection
RT	radiography testing
RTP	reactor thermal power
RV	reactor vessel
RWP	radiation work permit
S/G	steam generator
SDP	significance determination process
SF	spent fuel
SPT	station power transformer
SS	stainless steel
SSC	structure, system, and component
SW	service water
TS	technical specification(s)
TS/ODCM	Technical Specifications/Offsite Dose Calculation Manual
UE	unusual event
UFSAR	Updated Final Safety Analysis Report
UT	ultrasonic testing
VCT	volume control tank
VDC	volts direct current
VHRA	very high radiation area
VIB	vital instrument bus
VT	visual testing
WGE	work group evaluation
WO	work order