October 27, 2005

Mr. William Levis
Senior Vice President and Chief Nuclear Officer
PSEG Nuclear, LLC - N09
P. O. Box 236
Hancocks Bridge, NJ 08038

SUBJECT: SALEM NUCLEAR GENERATING STATION - NRC INTEGRATED INSPECTION REPORT 05000272/2005004 and 05000311/2005004

Dear Mr. Levis:

On September 30, 2005, the US Nuclear Regulatory Commission (NRC) completed an inspection at the Salem Nuclear Generating Station. The enclosed integrated inspection report documents the inspection findings, which were discussed on October 6, 2005, with Mr. Tom Joyce and other members of your staff.

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

The report documents two self-revealing findings of very low safety significance (Green). One of these findings was determined to involve a violation of NRC requirements. However, because of the very low safety significance and because it is entered into your corrective action program, the NRC is treating this finding as a non-cited violation (NCV) consistent with Section VI.A of the NRC Enforcement Policy. Additionally, a licensee-identified violation which was determined to be of very low safety significance is listed in this report. If you contest the non-cited violation, you should provide a response within 30 days of the date of this inspection report, with the basis for your denial, to the Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington, DC 20555-0001; with copies to the Regional Administrator, Region I; the Director, Office of Enforcement, United States Nuclear Regulatory Commission, Washington, DC 20555-0001; and the NRC Resident Inspector at the Salem Nuclear Generating Station.

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

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

Sincerely,

/RA/

Eugene W. Cobey, Chief
Projects Branch 3
Division of Reactor Projects

Docket Nos: 50-272; 50-311
License Nos: DPR-70; DPR-75

Enclosure: Inspection Report 05000272/2005004 and 05000311/2005004
w/Attachment: Supplemental Information

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U.S. NUCLEAR REGULATORY COMMISSION

REGION I

Docket Nos:	50-272, 50-311
License Nos:	DPR-70, DPR-75
Report No:	05000272/2005004, 05000311/2005004
Licensee:	Public Service Enterprise Group (PSEG) Nuclear LLC
Facility:	Salem Nuclear Generating Station, Units 1 & 2
Location:	P.O. Box 236 Hancocks Bridge, NJ 08038
Dates:	July 1, 2005, through September 30, 2005
Inspectors:	D. Orr, Senior Resident Inspector G. Malone, Resident Inspector J. Josey, Reactor Inspector K. Mangan, Senior Reactor Inspector T. Fish, Senior Operations Engineer B. Welling, Senior Project Engineer T. O'Hara, Reactor Inspector R. Barkley, Senior Reactor Inspector J. Cai, Human Factors Analyst, NRR
Approved By:	Eugene W. Cobey, Chief Projects Branch 3 Division of Reactor Projects

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SUMMARY OF FINDINGS

IR 05000272/2005004, 05000311/2005004; 07/01/2005 - 09/30/2005; Public Service Enterprise Group (PSEG) Nuclear LLC, Salem Units 1 and 2; Maintenance Effectiveness and Surveillance Testing.

The report covered a 13-week period of inspection by resident inspectors and announced inspections by operations engineers and reactor inspectors. One Green non-cited violation (NCV) and one Green finding were identified. The significance of most findings is indicated by their color (Green, White, Yellow, or Red) using Inspection Manual Chapter (IMC) 0609, "Significance Determination Process" (SDP). Findings for which the SDP does not apply may be Green or be assigned a severity level after NRC management review. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG-1649, "Reactor Oversight Process," Revision 3, dated July 2000.

A. NRC-Identified and Self-Revealing Findings

Cornerstone: Mitigating Systems

- Green. A self-revealing finding was identified for failure to implement corrective actions to create a preventive maintenance task to clean lube oil coolers on the station black-out air compressor (SBOAC). As a result, the SBOAC tripped due to a high air outlet temperature condition during a monthly performance test on August 14, 2005. PSEG entered the failure to perform necessary preventive maintenance into their corrective action program for resolution. The finding was not a violation of NRC requirements because it pertained to non-safety related equipment. The cause of the finding is related to the cross-cutting element of problem identification and resolution.

  Traditional enforcement does not apply because the issue did not have any actual safety consequences or potential for impacting the NRC's regulatory function and was not the result of any willful violation of NRC requirements. This finding was more than minor because it was associated with the equipment performance attribute, and it affected the mitigating systems cornerstone objective to ensure the availability of systems that respond to initiating events to prevent undesirable consequences. In accordance with Inspection Manual Chapter 0609, Appendix A, "Significance Determination of Reactor Inspection Findings for At-Power Situations," the inspectors conducted a Phase 1 Significance Determination Process (SDP) screening and determined that the safety function of the SBOAC, which is risk significant per 10 CFR 50.65, was lost for greater than 24 hours. This required that a Phase 2 SDP analysis be performed. Because the Salem Risk-Informed Inspection Notebook did not consistently describe the SBOAC, the regional Senior Reactor Analyst conducted a Phase 3 SDP analysis and determined the issue to be of very low safety significance. (Section 1R12.2)

- Green. A self-revealing non-cited violation was identified for PSEG's failure to comply with 10 CFR 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings." Operators performed surveillance procedure steps out of sequence, inadvertently tripping the 2A emergency diesel generator on undervoltage on August 18, 2005. PSEG entered the failure to implement a surveillance procedure into their corrective action program for resolution. The cause of the finding is related to the cross-cutting element of human performance.

  Traditional enforcement does not apply because the issue did not have any actual safety consequences or potential for impacting the NRC's regulatory function and was not the result of any willful violation of NRC requirements. This finding was more than minor because it was associated with the human performance attribute, and it affected the mitigating systems cornerstone objective to ensure the availability of systems that respond to initiating events to prevent undesirable consequences. In accordance with Inspection Manual Chapter 0609, Appendix A, "Significance Determination of Reactor Inspection Findings for At-Power Situations," the inspectors conducted a Phase 1 Significance Determination Process screening and determined the issue to be of very low safety significance. The finding was not a design or qualification deficiency, did not represent a loss of system safety function, did not represent an actual loss of safety function of a single train for greater than its Technical Specification allowed outage time, did not represent an actual loss of safety function of one or more non-Technical Specification trains of equipment designated as risk significant per 10 CFR 50.65 for greater than 24 hours, and did not screen as potentially risk significant due to external events. (Section 1R22)

B. Licensee Identified Violations

A violation of very low safety significance, which was identified by PSEG was reviewed by the inspectors. Corrective actions taken or planned by PSEG were entered into PSEG's corrective action program. This violation and corrective actions are listed in Section 4OA7 of this report.

REPORT DETAILS

Summary of Plant Status

Unit 1 began the period at 100 percent (%) power and remained at or near 100% power for the entire quarter.

Unit 2 began the period at 99.5% power. On August 21, 2005, after PSEG raised the normal operating average coolant temperature by one-degree Fahrenheit to improve main turbine generator electrical output, Unit 2 power was increased to 100%. Unit 2 operated at or near 100% power for the remainder of the quarter.

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems and Barrier Integrity

1R04 Equipment Alignment (71111.04)

a. Inspection Scope

Partial System Alignments (3 samples). The inspectors performed three partial equipment alignment inspections. The partial alignment inspections were completed during conditions when the equipment was of increased safety significance, such as would occur when redundant equipment was unavailable during maintenance or the equipment was recently returned to service after significant maintenance. The inspectors performed a partial walkdown of the following systems or trains to verify the equipment was aligned to perform its intended safety function:

- 11 Emergency diesel generator (EDG) fuel oil transfer pump on July 26, 2005, with the 12 EDG fuel oil transfer pump out of service;
- 1A and 1B EDGs and the 1A and 1B 4160 volt alternating current (VAC) switchgear on August 31, 2005, with the 1C EDG out of service; and
- 12A and 12B component cooling (CC) heat exchanger on September 8, 2005, with the 11 CC heat exchanger out of service.

The inspectors reviewed applicable documents and several corrective action notifications related to configuration control errors as listed in the Supplemental Information attachment to this report.

Complete System Alignment (1 sample). The inspectors performed one complete system alignment inspection of the Unit 1 residual heat removal system (RHR) to verify that the system was properly configured, hangers and supports correctly installed and functional, and to identify any discrepancies between the existing lineup and the prescribed lineup. The inspectors interviewed the system engineer. Additionally, the inspectors reviewed applicable documents as listed in the Supplemental Information attachment to this report.

b. Findings

No findings of significance were identified.

1R05 Fire Protection (71111.05)

a. Inspection Scope

Quarterly Fire Protection Walkdowns (71111-05Q - 10 samples). The inspectors walked down ten fire areas and observed combustible material control, fire detection and suppression equipment availability and compensatory measures. The inspectors reviewed Salem's Individual Plant Examination for External Events (IPEEE) for risk insights and design features credited in these areas. The inspectors also referenced Salem's pre-fire plans and NC.DE-PS.ZZ-0001-A6-GEN, "Programmatic Standard Salem Fire Protection Report-General." The following plant areas were inspected:

- Unit 1 and Unit 2 electrical penetration area;
- Unit 1 and Unit 2 mechanical penetration area;
- Unit 1 and Unit 2 service water intake structure;
- Unit 1 and Unit 2 demineralized ion exchanger area; and
- Unit 1 and Unit 2 reactor plant auxiliary equipment area.

Annual Fire Drill Inspection (71111-05A - 1 sample). The inspectors observed one fire drill on September 21, 2005, to determine the readiness of PSEG's fire brigade to prevent and respond to fires. The drill scenario involved a vital bus breaker fire located in the Unit 1 460 volt switchgear room. The inspectors verified the timeliness of the fire brigade response, the proper selection and placement of firefighting equipment, proper communication techniques between fire team members and the control room, and use of fire plans. Additionally, the inspectors observed the drill brief and post-drill critique.

b. Findings

No findings of significance were identified.

1R06 Flood Protection Measures (71111.06)

a. Inspection Scope (1 sample)

The inspectors performed one external flood protection measures inspection for Salem Units 1 and 2. All watertight flood protection doors, numerous auxiliary building penetration seals credited for wave runup protection, and the service water intake structure were walked down to verify operational readiness. Readiness of portable sump pumps was assessed, and the external flood protection engineer was interviewed. The inspectors reviewed applicable documents as listed in the Supplemental Information attachment to this report.

b. Findings

No findings of significance were identified.

1R11 Licensed Operator Requalification Program (71111.11)

a. Inspection Scope

Requalification Activities Review by Resident Staff (2 samples). The inspectors observed two simulator training scenarios conducted on July 29, 2005, and September 13, 2005, to assess operator performance and training effectiveness. The July 29 scenario involved a steam generator tube rupture preceded by a power range nuclear instrument anomaly, a loss of condenser vacuum, and a reactor coolant pump oil leak. The September 13 scenario involved a large break loss-of-coolant accident (LBLOCA) preceded by a containment fan coil unit breaker trip, main steam pressure transmitter (PT-507) failure, and a stuck-open steam dump valve. The LBLOCA was complicated with a 2A vital bus failure and failure of two phase ‘A’ containment isolation valves to close. The inspectors assessed simulator fidelity and observed the simulator instructors’ critique of operator performance. Documents associated with this inspection activity are listed in the Supplemental Information attachment to this report.

Biennial Review by Regional Staff (1 sample). The following inspection activities were performed using NUREG-1021, Revision 9, “Operator Licensing Examination Standards for Power Reactors,” and Inspection Procedure Attachment 71111.11, “Licensed Operator Requalification Program,” and 10 CFR 55.46, Simulator Rule.

The inspectors reviewed documentation of operating history since the last requalification program inspection. The inspectors also discussed facility operating events with the resident staff. Documents reviewed included NRC inspection reports and PSEG notifications to ensure that operational events were not indicative of possible training deficiencies. Inspectors reviewed the following notifications to evaluate the need for training involvement: 20191254, related to automatic safety injection reset; 20197693, related to unintentional entry into Technical Specification 3.0.3; 20238416, related to application of an incorrect main turbine ramp rate; and 20239469, related to probabilistic safety assessment changing to red due to 2B emergency diesel generator being inoperable.

The inspectors reviewed three comprehensive written exams the facility administered to licensed operators in September and October 2004, at the completion of the previous two year training cycle. The written exams for the current cycle were not reviewed, because they have not yet been developed and will be administered in September and November 2006. In addition, the inspectors reviewed four scenarios and ten job performance measures (JPMs) administered during this current annual operating exam period to ensure the quality of these exams met the criteria established in the Examination Standards (NUREG 1021) and 10 CFR 55.59.

The inspectors observed the administration of operating examinations to two operating shifts comprising 28 operators. Each licensed operator was examined on two simulator scenarios and five JPMs.

The inspectors interviewed instructors, training and operations department management personnel, and licensed operators for feedback regarding the implementation of the licensed operator requalification program to ensure the requalification program was meeting their needs and responsive to their comments regarding the quality of the requalification program.

Inspectors reviewed four remediation training records; three records were associated with three operators who failed their comprehensive written exam, and one record was associated with an operating crew that failed a scenario evaluation.

Conformance with operator license conditions was verified by reviewing the following records:

- A sample of attendance records for the current training cycle;
- 15 medical records (previously sampled during site visit in April 2005); and
- A sample of proficiency watch-standing records, reactivation records, and license renewal records.

The inspectors observed simulator performance during the conduct of the examinations, reviewed simulator performance tests (e.g., steady state performance tests, selected transient tests, and selected malfunction tests), and simulator action requests to verify compliance with the requirements of 10 CFR 55.46 and guidance contained in ANSI/ANS-3.5-1993. The following tests and data were reviewed.

- Steady State Accuracy Tests
    - 2004 Steady State Comparison Tests
    - 2004 Simulator Stability Test
- Transient Tests
    - Transient Test For All Main Steam Isolation Valve Closure (test ‘c’)
    - Transient Test For Turbine Trip Which Does Not Result in Reactor Trip (test ‘f’)
    - Transient Test For Maximum Size Reactor Coolant System Rupture Combined with Loss of All Offsite Power (test ‘h’)
- Malfunction Tests
    - RC001, Reactor Coolant System Rupture of Reactor Coolant Loop
    - RC002, Reactor Coolant System Leak into Containment

b. Findings

No findings of significance were identified.

1R12 Maintenance Implementation (71111.12)

a. Inspection Scope (2 samples)

The inspectors reviewed performance monitoring and maintenance effectiveness issues for two components: the Salem Unit 1 and Unit 2 chemical volume and control system

(CVCS) positive displacement pumps (13 and 23 PDPs) and the station blackout air compressor (SBOAC). The inspectors assessed whether PSEG was adequately monitoring equipment performance to ensure that preventive maintenance was effective. The inspectors verified that the components were monitored in accordance with the maintenance rule program requirements. The inspectors compared documented functional failure determinations and unavailability hours to those being tracked by PSEG to evaluate the effectiveness of PSEG's condition monitoring activities and to determine whether performance goals were being met. The inspectors reviewed applicable work orders, corrective action notifications, preventive maintenance tasks, and system health reports. Documents associated with this inspection activity are listed in the Supplemental Information attachment to this report.

b. Findings

1. Chemical Volume Control System (CVCS) Positive Displacement Pump (PDP) Maintenance Rule Applicability

The issue involving maintenance rule applicability for the CVCS PDPs is unresolved pending further inspector review.

In late 2002, PSEG completed a design change (80029150) that installed an inter-unit cross-tie of the CVCS to provide continued charging flow in a post fire condition. PSEG revalidated a post fire safe shutdown analysis and determined that the existing safe shutdown charging pumps required cable separation or protection upgrades. PSEG stated in evaluation 80029150 that greater plant safety could be achieved by installing a charging cross-tie between the Salem Units rather than protecting impacted cables associated with the charging system. The charging cross-tie resulted in having all active components associated with a new, alternate charging train in a totally separate fire area (i.e. the opposite or unaffected unit). The alternate charging train consisted of the existing non-safety related PDP and a newly installed CVCS cross-tie, and according to PSEG, provided a suitable fix for addressing postulated fires.

The inspectors noted that the PDPs were scoped for rapid boration of the opposite unit during the post-fire shutdown via the cross-tie, yet the function to provide reactor coolant pump (RCP) seal injection via the cross-tie for post-fire shutdown was not scoped in SC.ER-DG.ZZ-0002, "System Function Level Maintenance Rule Scoping versus Risk Reference."

The inspectors identified that S1/S2.OP-AB.LOOP-0001, "Loss of Offsite Power," Revision 12, provided guidance to use the CVCS cross-tie during non-fire abnormal operating conditions. However the original 10 CFR 50.59 safety analysis (PSEG order 80029150) that evaluated its use during post fire scenarios specifically stated if the cross-ties are used or credited for any other event, a separate safety evaluation will be generated. S1/S2.OP-AB.LOOP-0001, "Loss of Offsite Power," Revision 12, did not have a separate safety evaluation and inappropriately credited safety analysis 80029150.

PSEG recognized on June 9, 2004, in notification 20191176 that procedures S1/S2.OP-AB.LOOP-0001, “Loss of Offsite Power,” were in conflict with an overriding emergency operating procedure, 1/2-EOP-LOPA-1, “Loss of All AC Power.” On August 15, 2004, PSEG revised procedures S1/S2.OP-AB.LOOP-0001, “Loss of Offsite Power,” Revision 15, to resolve the procedure conflicts. This revision prevented operators from aligning seal injection via the CVCS cross-tie during loss of power scenarios because procedural guidance was not adequate to prevent thermally shocking the RCP seal packages. The inspectors questioned whether PSEG properly resolved this issue to minimize plant risk during loss of power scenarios. The inspectors considered that revising 1/2-EOP-LOPA-1, “Loss of All AC Power,” to include restoration of seal injection via the CVCS cross-tie with proper precautions to prevent thermally shocking the RCP seal packages may have minimized plant risk. PSEG also initiated notification 20216063 on December 16, 2004, with similar concerns and stated that the baseline core damage frequency for the Salem units would be reduced. To date no action was taken regarding notification 20216063.

The inspectors also noticed inconsistent procedure guidance for using the CVCS cross-tie under different abnormal operating conditions. For instance, procedures S1.OP-AB.CVC-0001, Revision 1, and S2.OP-AB.CVC-0001, Revision 2, “Loss of Charging,” provided guidance to use the CVCS cross-tie, yet procedure S1.OP-AB.RCP-0001, Revision 11, and S2.OP-AB.RCP-0001, Revision 16, “Reactor Coolant Pump Abnormality,” did not direct use of the CVCS cross-tie for loss of seal injection scenarios. S1/S2.OP-AB.CVC-0001, “Loss of Charging,” also did not provide precautions to prevent thermally shocking the RCP seal packages when seal injection was restored. S1/S2.OP-AB.SW-0005, “Loss of Service Water,” Revision 2, also did not direct use of the CVCS cross-tie. S1/S2.OP-AB.SW-0005, “Loss of Service Water,” used an alternate strategy to align cooling water through temporary hoses and restore the affected units centrifugal charging pumps while operating the component cooling water system without service water cooling to provide thermal barrier heat exchanger cooling to the RCP seal packages.

This issue is unresolved pending inspector review of PSEG’s corrective actions to resolve the maintenance rule scoping, 10 CFR 50.59 safety evaluations, and procedure quality and consistency issues for the CVCS cross-tie. PSEG issued corrective action notifications 20254207, 20253052, 20253019, and 20253153 to address the CVCS cross-tie implementation issues. **(URI 05000272&311/2005004-01, CVCS Cross-Tie Implementation)**

2. <u>Unavailability of Station Black-Out Air Compressor due to Incomplete Preventive Maintenance</u>

<u>Introduction</u>. A self-revealing finding was identified for failure to implement effective corrective actions when the station black-out air compressor (SBOAC) tripped due to high discharge air temperature on August 14, 2005. This finding was of very low safety significance (Green). Because the corrective action issues involved non-safety related equipment, there was no violation of regulatory requirements.

Description. On August 14, 2005, the SBOAC was started for monthly performance test, SC.OP-PT.CA-0001, “SBO Diesel Control Air Compressor Test.” The SBOAC tripped due to a high outlet air temperature approximately 25 minutes into a 60 minute run. PSEG identified through troubleshooting that outlet temperatures would remain below the trip set-point of 255 degrees Fahrenheit (EF) if sound dampening covers were removed from the compressor, allowing improved heat transfer from the oil cooler to the surrounding air. PSEG also identified that the air-cooled oil coolers had an oily film with dust and dirt deposits.

PSEG entered this issue into the corrective action program as notification 20249774. PSEG identified that a similar condition occurred in 2002. The evaluation for the 2002 condition identified the need for a preventive maintenance (PM) task to clean the SBOAC coolers at a 3-year frequency. The PM task was not developed. PSEG identified the apparent cause as inadequate corrective actions to create PM tasks to clean the coolers.

Analysis. The inspectors determined that not performing preventive maintenance to clean the SBOAC was a performance deficiency. Corrective actions were not completed by the assigned due date contrary to PSEG procedure NC.WM-AP.ZZ-0002, “Performance Improvement Process.” PSEG did not implement corrective actions to periodically clean SBOAC coolers, and as such, unnecessarily rendered the SBOAC unavailable during a period of high outside temperatures. Specifically, the inspectors determined that when outside air temperature was above about 90 EF the SBO compressor reliability was affected.

Traditional enforcement does not apply because the issue did not have any actual safety consequences or potential for impacting the NRC’s regulatory function, and it was not the result of any willful violation of NRC requirements. This issue was more than minor because it affected the equipment performance attribute of the Mitigating Systems cornerstone and impacted the cornerstone objective of ensuring the availability and reliability of the SBOAC to respond to a loss of control air initiating event to prevent undesirable consequences.

In accordance with IMC 0609, Appendix A, "Significance Determination of Reactor Inspection Findings for At-Power Situations," the inspectors conducted a Phase 1 SDP screening and determined that a Phase 2 Analysis was needed. The inspectors assumed that the SBOAC, a non-technical specification train of equipment designated as risk-significant per 10 CR 50.65, was unavailable for greater than 24 hours. The exposure time was based on National Atmospheric and Oceanographic Administration climate data that on average the Salem site temperature would exceed 90 F for 21 days a year, using the data for both Philadelphia, Pa and Atlantic City, NJ.

Because the Salem Risk-Informed Inspection Notebook did not consistently describe the SBOAC, (the SBOAC was listed as having a mitigating safety function in Table 3.14, but was not listed in Table 2 of the Salem Risk-Informed Inspection Notebook, Rev. 1) a regional Senior Reactor Analyst (SRA) conducted a Phase 3 SDP analysis. The SRA determined the finding to be of very low safety significance (Green) based on the estimated increase in core damage frequency (ΔCDF) due to internal and external initiating events, with no associated increase in the large early release frequency (ΔLERF).

ΔCDF Due to Internal Initiating Events. The SRA used Table 3.14 and estimated ΔCDF for internal initiating events to be on the order of 1 core damage accident in 6,000,000 years of reactor operation (in the low E-7 core damage events per year range), assuming that the SBOAC would not function for 3 to 30 days. The dominant core damage sequence involved a loss of instrument air and the failure of the SBO compressor, with subsequent failure of auxiliary feed water and failure of the operators to conduct feed and bleed cooling of the reactor.

ΔCDF Due to External Initiating Events. The SRA determined the additional risk impact due to external events because the ΔCDF for internal initiating events was in the low E-7 range. The SRA determined that external initiators did not contribute to the total ΔCDF relative to the SBOAC. The SRA reviewed the Salem Individual Plant Examination of External Events (IPEEE) report and a risk tool developed by the Office of Nuclear Reactor Regulation and its contractor, Brookhaven National Laboratory, "External Initiator Risk Characterization for USNRC's Significance Determination Process (Augmented Worksheets for Salem Nuclear Generating Station)," (BNL-73674-2005).

ΔLERF. There was no ΔLERF, because the Salem facility has a large dry containment and in accordance with IMC 0609, Appendix H, this Type A finding did not involve a steam generator tube rupture or an interfacing system loss-of-coolant accident.

The performance deficiency associated with the unavailability of the SBOAC has a problem identification and resolution cross-cutting aspect.

Enforcement. The finding was not a violation of NRC requirements, in that, the corrective action deficiencies involved non-safety related equipment. PSEG entered this problem into their corrective action program in notification 20249774. **(FIN 05000272&311/2005004-02, Unavailability of Station Black-Out Air Compressor due to Incomplete Preventive Maintenance)**

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

a. Inspection Scope (7 samples)

The inspectors reviewed seven on-line risk management evaluations through direct observation and document reviews for the following configurations:

- Planned unavailability of the 11 and 12 containment fan cooling units (CFCU) during an 11 residual heat removal pump surveillance test on July 21, 2005;

- Unplanned unavailability of the station blackout air compressor on August 15, 2005;
- Unplanned unavailability of the 1B emergency diesel generator on August 22, 2005;
- Unplanned unavailability of the 22 service water nuclear header on August 22, 2005;
- Unplanned unavailability of the 22 electrical penetration area exhaust fan on August 24, 2005;
- Unplanned unavailability of the 1C emergency diesel generator on August 30, 2005; and
- Planned unavailability of the 11 component cooling water heat exchanger on September 8, 2005.

The inspectors reviewed the applicable risk evaluations, work schedules and control room logs for these configurations to verify that concurrent planned and emergent maintenance and test activities did not adversely affect the plant risk already incurred with these configurations. PSEG's risk management actions were reviewed during shift turnover meetings, control room tours, and plant walkdowns. The inspectors also used PSEG's on-line risk monitor to gain insights into the risk associated with these plant configurations. Documents reviewed are listed in the Supplemental Information attachment to this report.

b. Findings

No findings of significance were identified.

1R15 Operability Evaluations (71111.15)

a. Inspection Scope (5 samples)

The inspectors reviewed five operability determinations for degraded or non-conforming conditions associated with:

- Service water piping trunnion support gaps and corrosion (20246849, 20250391 & 20251879) on July 14, 2005;
- 11 service water accumulator to containment fan coil unit silting (70048714) on July 29, 2005;
- High river water temperatures (70049239) on August 3, 2005;
- Station blackout compressor high air temperature trip (20249774) on August 14, 2005; and
- 1B emergency diesel generator failure to stop from local control panel (20250868 & 70050181) on August 31, 2005.

The inspectors reviewed the technical adequacy of the operability determinations to ensure the conclusions were technically justified. The inspectors also walked down accessible equipment to corroborate the adequacy of PSEG's operability determinations. Documents reviewed are listed the Supplemental Information attachment to this report.

b. Findings

No findings of significance were identified. However, issues involving the service water piping trunnion support gaps and corrosion are unresolved pending inspector review of PSEG's assessment calculations for piping supports not in conformance with original design plans. This issue was entered into PSEG's corrective action program as notifications 20246849, 20250391, 20251879, and 20255706. **(URI 05000272&311/2005004-03, Service Water Piping Trunnion Support Gaps)**

1R19 Post Maintenance Testing (71111.19)

a. Inspection Scope (6 samples)

The inspectors observed portions of and reviewed results of six post maintenance tests (PMT) for the following equipment:

- 15 service water pump discharge expansion joint replacement on August 8, 2005;
- 11 component cooling water pump on August 16, 2005;
- 13 containment fan cooling unit flow transmitter on August 18, 2005;
- 1B emergency diesel generator on August 23, 2005;
- 1C emergency diesel generator on September 1, 2005; and
- 25 service water pump on September 1, 2005.

The inspectors assessed whether: (1) the effect of testing on the plant had been adequately addressed by control room and engineering personnel; (2) testing was adequate for the maintenance performed; (3) acceptance criteria were clear and adequately demonstrated operational readiness consistent with design and licensing basis documentation; (4) test instrumentation had current calibration, range, and accuracy for the application; (5) tests were performed, as written, with applicable prerequisites satisfied; and (6) equipment was returned to an operational status and ready to perform its safety function. Documents reviewed to verify post maintenance testing adequacies are listed in the Supplemental Information attachment to this report.

b. Findings

No findings of significance were identified.

1R20 Refueling and Other Outage Activities (71111.20)

a. Inspection Scope (1 partial sample)

On September 27, 2005, the inspectors observed new fuel receipt inspections for two fuel assemblies in preparation for the October 2005 Unit 1 refueling outage, 1R17. Inspection activities included record reviews, interviews, and direct observation of new fuel inspection and fuel movement into the spent fuel pool. The inspectors verified fuel met design features for fuel storage as described in Technical Specifications, equipment was properly tested prior to handling new fuel, fuel was properly examined to verify no damage occurred during shipment, and nuclear material accountability was properly maintained. The inspectors verified the evolution was performed according to work order 30103156 and station procedures SC.RE-FR.ZZ-0001, "Fuel Handling," SC.RE.FR.ZZ-0002, "New Fuel Receipt and Storage," and SC.RE.FM.ZZ-0001, "Special Nuclear Material Control and Accounting."

b. Findings

No findings of significance were identified.

1R22 Surveillance Testing (71111.22)

a. Inspection Scope (5 samples)

The inspectors observed portions of and reviewed results for the following five surveillance tests:

- 12 charging pump inservice testing on July 5, 2005;
- 11 auxiliary feedwater pump inservice testing on July 20, 2005;
- Unit 1 component cooling water inservice valve testing on July 20, 2005;
- 11 component cooling water pump inservice testing on August 16, 2005; and
- 2A emergency diesel generator monthly testing on August 18, 2005.

The inspectors evaluated the test procedures to verify that applicable system requirements for operability were adequately incorporated into the procedures and that test acceptance criteria were consistent with the Technical Specification requirements and the updated final safety analysis report (UFSAR). The inspectors reviewed applicable documents associated with surveillance testing as listed in the Supplemental Information attachment to this report.

b. Findings

Introduction. A self-revealing non-cited violation was identified when an equipment operator inadvertently tripped the 2A emergency diesel generator during surveillance testing on August 18, 2005. The finding was of very low safety significance (Green) and a non-cited violation of 10 CFR 50, Appendix B, Criterion V, "Instruction, Procedures, and Drawings."

Description. On August 18, 2005, the 2A EDG tripped on undervoltage when an equipment operator performed an out-of-sequence step to exercise the voltage regulator potentiometer. The monthly surveillance test S2.OP-ST.DG-0001, "2A Diesel

Generator Surveillance Test," was in progress. Step 5.7.1 of the surveillance procedure required the operator to open the 2A diesel generator output breaker. This step was marked as completed on the procedure but was not actually completed. Step 5.7.3 of the surveillance procedure directed the operator to exercise the voltage regulator potentiometer using the voltage control switch. When step 5.7.3 was performed, the diesel generator tripped on undervoltage due to a loss of excitation voltage. The 2A EDG was unavailable for 53 minutes while operators investigated the trip and reset tripped relays.

PSEG's corrective action evaluation concluded that the human performance error was caused by inadequate self and peer checking. Specifically, the operator did not use a second operator to peer check his actions and did not correlate the action to exercise the voltage regulator potentiometer with the effect on the 2A EDG.

Analysis. The performance deficiency associated with the EDG trip was that certain procedure steps were not performed in sequence as directed by S2.OP-ST.DG-0001, "2A Diesel Generator Surveillance Test," which resulted in 2A EDG being unavailable for 53 minutes.

Traditional enforcement does not apply because the issue did not have any actual safety consequences or potential for impacting the NRC's regulatory function and was not the result of any willful violation of NRC requirements. This finding was more than minor because it was associated with the human performance attribute, and it affected the mitigating systems cornerstone objective to ensure the availability of systems that respond to initiating events to prevent undesirable consequences. The human performance errors led to unavailability of the 2A EDG. In accordance with IMC 0609, Appendix A, "Significance Determination of Reactor Inspection Findings for At-Power Situations," the inspectors conducted a Phase 1 SDP screening and determined the issue to be of very low safety significance (Green). The finding was not a design or qualification deficiency, did not represent a loss of system safety function, did not represent an actual loss of safety function of a single train for greater than its Technical Specification allowed outage time, did not represent an actual loss of safety function of one or more non-Technical Specification trains of equipment designated as risk significant per 10CFR50.65, for greater than 24 hours, and did not screen as potentially risk significant due to external events. The performance deficiency associated with the 2A EDG trip has a human performance cross-cutting aspect.

Enforcement. 10 CFR 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," requires, in part, that activities affecting quality shall be prescribed by documented procedures and shall be accomplished in accordance with these procedures. Contrary to the above, on August 18, 2005, the surveillance test of 2A EDG was not accomplished in accordance with procedure S2.OP-ST.DG-0001, "2A Diesel Generator Surveillance Test" and resulted in the 2A EDG tripping on undervoltage. The 2A EDG was unavailable for 53 minutes. Because this finding is of very low safety significance and has been entered into the corrective action program in notification 20250244, this violation is being treated as a NCV, consistent with section

VI.A of the NRC Enforcement Policy. **(NCV 05000311/2005004-04, 2A Emergency Diesel Generator Inoperable due to Operator Procedure Error)**

1R23 Temporary Plant Modifications (71111.23)

a. Inspection Scope (2 samples)

The inspectors reviewed temporary modifications 80083638, “Install Jumper to Power 12 Containment Fan Cooling Unit (CFCU) From Low Speed Breaker Via High Speed Power Cables,” installed on July 29, 2005, and 04-033 & 034, “Temporary Removal of Power to S1SW-1SV590 & 591,” installed on September 21, 2005. The inspectors assessed whether PSEG followed its administrative process for implementing the modifications, NC.DE-AP.ZZ-0030, “Control of Temporary Modifications,” and verified that each temporary modification did not adversely impact the operation and performance of the associated structure, system, or component. The inspectors verified that the modifications did not affect the operators’ response to abnormal or emergency conditions.

Temporary modification 80083638 involved use of the high speed power cables in conjunction with the low speed breaker to power the low speed CFCU motor windings. The original low speed cables had an electrical ground on the ‘A’ phase cable.

Temporary modifications 04-033 & 034 were identical in nature and de-energized the 1A and 1B emergency diesel generator (EDG) service water inlet cooling valves in the open position to eliminate a potential valve binding issue from affecting EDG operability. The 1C EDG and Unit 2 EDGs were verified not susceptible to the binding issue and did not require temporary modifications. The binding issue was identified in PSEG notification 20253345 on September 19, 2005, during surveillance testing of the 1B EDG.

b. Findings

No findings of significance were identified.

Cornerstone: Emergency Preparedness [EP]

1EP6 Drill Evaluation (71114.06)

a. Inspection Scope (2 samples)

The inspectors evaluated an emergency preparedness drill from the control room simulator and the Technical Support Center on August 16, 2005, and a licensed operator requalification examination on September 13, 2005, both of which contributed to the NRC’s Drill/Exercise Performance performance indicator. The inspectors evaluated drill performance relative to developing classifications, notifications, and protective action recommendations by PSEG personnel. The inspectors reviewed the Salem Event Classification Guides and Emergency Plans. The inspectors referenced

Nuclear Energy Institute 99-02, “Regulatory Assessment Performance Indicator (PI) Guidelines,” and verified that PSEG correctly counted these drill contributions to the NRC PI for Drill/ Exercise Performance.

b. Findings

No findings of significance were identified.

4. OTHER ACTIVITIES [OA]

4OA2 Identification and Resolution of Problems (71152)

3. Review of Items Entered into the Corrective Action Program

As required by Inspection Procedure 71152, "Identification and Resolution of Problems," and in order to help identify repetitive equipment failures or specific human performance issues for follow-up, the inspectors performed a daily screening of items entered into PSEG's corrective action program. This review was accomplished by reviewing hard copies of each condition report, attending daily screening meetings, or accessing PSEG's computerized database.

4. Annual Sample Reviews (71152 - 2 samples)

.1 PSEG Efforts to Improve Engineering Performance

a. Inspection Scope

The inspectors selected for detailed review a range of documents to assess PSEG’s progress in improving the performance of their engineering organization. These improvement initiatives were discussed with the NRC in November and December 2004 and included a range of new programs, processes and resources focused on improving the overall performance of Salem and Hope Creek engineering departments.

In particular, the inspectors reviewed NC.CA-DG.ZZ-0102, Revision 0, “Operational and Technical Decision-Making (OTDM) Process Desk Guide;” SH.SE-AS.ZZ-0001(Z)-Rev. 0, “Site Engineering Technical Evaluations;” and NC.CA-DG.ZZ-0103, Revision 1, “Adverse Condition Monitoring and Contingency Planning.” The inspectors also reviewed a range of organizational performance indicators, system health reports for maintenance rule a(1) systems at Salem and Hope Creek, and draft or recently created programs involving the Quality Review Team (QRT), margin management, Material Condition Improvement (MCIP) and technical rigor. The current and pending organization charts for engineering were also reviewed, along with PSEG’s transition plan for moving from its current to future organizational structure.

The inspectors spoke with several engineering managers and directors to discuss performance improvement initiatives as well as review various indicators of trends in engineering product quality and the reduction of engineering backlogs. To independently review the quality of engineering work products, the inspectors reviewed several 10 CFR 50.59 evaluations, OTDMs and Engineering Response Team (ERT) reports. Finally, a recently completed design engineering self-assessment of engineering product quality was also reviewed.

b. Findings and Observations

No findings of significance were identified.

The inspectors noted that PSEG is in various stages of implementing the performance improvement initiatives discussed with the NRC in November and December 2004. Several programs, most notably the OTDM process, were well established while other programs were in the early stages of implementation. Evidence of performance improvement was demonstrated based on the quality of the engineering products and the self-assessment reviewed by the inspectors, the large reduction in the design engineering backlog and positive trends in various engineering department performance indicators.

.2 Corrective Actions For 1SJ6 Leak Issues

a. Inspection Scope

In April 2005, PSEG discovered a leaking weld at a pipe elbow near valve 1SJ6. The leaking component is an ASME, Class 2 component governed by Technical Specification 3.4.11.b. At the time of discovery, the plant was operating at 100% power. Isolation of the leaking elbow weld necessitated closure of valves which isolated all high pressure safety injection flow to the reactor coolant system. This necessitated entry into Technical Specification 3.0.3, and shutdown of the plant to isolate and repair the leaking weld. The inspectors reviewed Unit 1 licensee event report (LER) 2005-002-00 and associated notifications, work orders, root cause reports and the resulting corrective actions for the 1SJ6 pipe leak.

Additionally, the inspectors reviewed Unit 2 LER 2005-002-00 and associated notifications, work orders, root cause reports and the resulting corrective actions associated with the reactor coolant instrument tubing through wall leaks discovered two days prior to the April 2005 refueling outage. The inspectors also reviewed a sample of notifications dealing with Boric Acid Corrosion Control issues.

b. Findings and Observations

No findings of significance were identified. Boric Acid Corrosion Control notifications were properly documented and corrective actions were appropriate for the conditions described.

In regards to the reactor coolant instrument tubing leaks, notification 20231322 did not specify actions to avoid or eliminate service water leaks in containment, which contributed to the tubing leak problem. There were no corrective actions identified to evaluate the stress caused to the tubing by the clamping arrangement which contributed to the leak mechanism at two locations. PSEG initiated notification 20255322 to capture and evaluate this condition.

The 1SJ6 pipe weld was reported via notification 20234828 on April 19, 2005. The leaking weld, piping, and valve 1SJ6 were removed and the pipe was capped. PSEG's extent of condition review identified several additional locations as susceptible to the same failure mechanism. PSEG initiated actions to continue visual inspections to monitor for through wall leaks at all locations at an eighteen month periodicity. PSEG initiated notification 20255323 to examine the effectiveness of the corrective actions for the 1SJ6 repair.

3. <u>Safety Conscious Work Environment Metric Review</u>

b. <u>Inspection Scope</u>

The inspectors reviewed PSEG's progress in addressing safety conscious work environment (SCWE) issues that were discussed in the NRC's annual assessment letter dated March 3, 2005. In that letter, the NRC staff documented a SCWE substantive cross-cutting issue and stated the NRC's intention to continue to monitor progress in this area.

The inspectors conducted a sampling review of PSEG's SCWE Metrics, or performance indicators (PIs), for the second quarter of 2005 on September 15 and 16, 2005.

Documents reviewed for this inspection activity are listed in the Supplemental Information attachment to this report.

c. <u>Findings and Observations</u>

No findings of significance were identified.

In the second quarter of 2005, PSEG identified 17 PIs as being green (satisfactory) while 12 were identified as red (needs improvement). These results were approximately consistent with the results in the first quarter of 2005, indicating no notable improvement or decline.

The inspectors identified inconsistencies in four of the PIs. These PIs showed numerical increases, indicative of possible adverse trends in equipment reliability, but were considered "Green, No Adverse Trend." Specifically, the Salem Unit 1, Salem Unit 2, and Hope Creek Repeat Maintenance PIs; and the Hope Creek Operational Challenges PI all showed increasing numbers, but remained "Green." The inspectors noted that the supporting information for these PIs did not address PSEG's determination that "No Adverse Trend" existed, despite the numerical increases. PSEG initiated notification 20253539 within their corrective action program to review these issues.

4. Cross-References to PI&R Findings Documented Elsewhere

Section 1R12.2 describes a finding in which PSEG did not preclude the repetition of a station blackout air compressor malfunction.

4OA3 Event Followup (71153 - 4 LER samples)

1. (Closed) LER 05000272/2005003-00, Emergency Core Cooling System (ECCS) Leakage Outside Containment Exceeds Dose Analysis Limits (Seal Injection Filter Replacement)

This LER described excessive ECCS boundary leakage to the auxiliary building during reactor coolant pump seal water injection filter maintenance that occurred on May 3, 2005. During followup log reviews, PSEG determined that similar leakage also existed on October 27, 2003. PSEG determined the apparent cause for the excessive leakage was due to inadequate isolation of the seal injection filter. Other factors contributing to this event were related to human performance deficiencies that allowed the leakage to go uncorrected for about 24 hours and insufficient operational guidance on investigating and reporting anomalous leakage. Corrective actions planned by PSEG included seal injection filter isolation valve repair, training on lessons learned, and ECCS leakage monitoring program enhancements. No new findings were identified in the inspector's review. The inspectors determined that this issue represented a minor performance deficiency, because there was not an actual radiological consequence due to the ECCS boundary leakage. Further, the administrative leakage limits in the post-accident recirculation path provide defense in depth by conservatively assuming core damage and to ensure the radiation doses to control room operators would be within 10 CFR 50 General Design Criterion 19 limits. This finding constitutes a violation of minor significance that is not subject to enforcement action in accordance with Section IV of the NRC's Enforcement Policy. PSEG documented the problem in notification 20236947. This LER is closed.

2. (Closed) LER 05000311/2005004-00, Required Post Maintenance Testing Not Performed on Containment Isolation Valves

On June 15 and June 17, 2005, PSEG identified that two containment isolation valves, 2SS49 and 21SS182, were inoperable and the associated TS limiting condition for operation had not been entered. The containment isolation valves were reactor coolant sampling system valves. On November 18, 2004, the 2SS49 valve stem packing was tightened and an as left local leak rate test (LLRT) was not performed and on May 24, 2004, the 21SS182 valve stem packing was also tightened and an as left LLRT was not performed. PSEG determined the cause to be insufficient work planning detail. Corrective actions included incorporate the Work-It-Now Team planning guide into the more structured station work planning guide. This finding is more than minor because it had a credible impact on safety, in that if the redundant valves in the penetration did not close on a containment isolation signal, containment integrity would not be ensured. The finding affects the Barrier Integrity Cornerstone and was considered to have very low safety significance (Green) using Appendix H of the SDP because the likelihood of an accident leading to core damage was not affected, the probability of early primary containment failure and therefore a large early release was negligible, and the redundant containment isolation valves remained operable during this event. This licensee-identified finding involved a violation of TS 3.6.3, Containment Isolation Valves. The enforcement aspects of the violation are discussed in Section 4OA7. This LER is closed.

3. (Closed) LER 05000272/2005002-00, Technical Specification 3.0.3 Required Plant Shutdown - Sample Line Leak

This LER described a through wall leak at the weld of a boron injection tank sample valve. Isolation of the leak location, required for the circumstances by Technical Specification 3.4.10.1, action b., isolated all safety injection flow via the charging pumps to the reactor coolant system. Operators subsequently entered Technical Specification 3.0.3 and shutdown Salem Unit 1 in a controlled fashion. The LER was reviewed by the inspectors and no findings of significance were identified and no violation of NRC requirements occurred. PSEG documented the through wall leak in notification 20234828. This LER is closed.

4. (Closed) LER 05000311/2005002-00, Reactor Coolant Instrument Line Through-Wall Leak

In April 2005, PSEG discovered through wall leaks on several instrument tubes associated with Unit 2 reactor coolant system flow measurement instrumentation. These tubes are ASME Class 2 and governed by Technical Specification 3.4.10.b. PSEG documented the leaks in notifications 20231322, 20233095 and 20236992. Station personnel completed an extensive inspection and cleaning effort for other affected tubing and completed a root cause analysis on this issue. All affected tubing was replaced. This issue was the subject of a non-cited violation, NCV-05000311/2005-03-02, issued in NRC Inspection Report 05000311/2005003. The LER was reviewed by the inspectors. No new issues were identified in the LER inspection review. This LER is closed.

4OA4 Cross-Cutting Aspects of Findings

Section 1R22 of this report describes a finding with inadequate procedural adherence that resulted in an inoperable emergency diesel generator. The operators' error had a human performance cross-cutting aspect.

4OA6 Meetings, Including Exit

Management Site Visit. On August 25, 2005, a site visit was conducted by Mr. William F. Kane, Deputy Executive Director for Reactor and Preparedness Programs for the NRC. During Mr. Kane's visit, he toured the Salem and Hope Creek plants and met with PSEG managers.

Exit Meeting. On October 6, 2005, the resident inspectors presented the inspection results to Mr. Tom Joyce and other members of his staff who acknowledged the findings. The inspectors confirmed that proprietary information was not provided or examined during the inspection.

4OA7 Licensee-Identified Violations

The following violation of very low significance (Green) was identified by PSEG and is a violation of NRC requirements which meets the criteria of Section VI of the NRC Enforcement Policy, NUREG-1600, for being dispositioned as an NCV.

- Technical specification 3.6.3 requires that a primary containment penetration be isolated within four hours, if the associated containment isolation valve (CIV) is not operable. Contrary to this, on May 24, 2004 to June 17, 2005, 21SS182, and on November 18, 2004, to June 15, 2005, 2SS49, were not operable, and the penetrations were not isolated within four hours. This was identified in PSEG's corrective action program as notification 20243873. This finding is of very low safety significance because it did not represent an open pathway in the physical integrity of the reactor containment.

ATTACHMENT: SUPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee personnel
T. Joyce, Salem Vice President
M. Gallagher, Vice President - Engineering
C. Fricker, Plant Manager
S. Robitzski, Salem Engineering Director
T. Gierich, Operations Manager
R. Coon, Salem Training Director
G. Sosson, System Engineering Manager
S. Mannon, Regulatory Assurance Manager
D. Labott, Project Manager, Reactor Head Replacement
W. Treston, PSEG ISI Manager
J. Sullivan, Salem Assistant Operations Manager
M. Kafantaris, Salem Operations Training Manager
M. Swartz, Simulator Supervisor
R. Swartzwelder, System Engineer

LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

05000272&311/2005004-01	URI	CVCS Cross-Tie Implementation (Section 1R12.1)
05000272&311/2005004-03	URI	Service Water Piping Trunnion Support Gaps (Section 1R15)

Opened/Closed

05000272&311/2005004-02	FIN	Unavailability of Station Black-Out Air Compressor due to Incomplete Preventative Maintenance (Section 1R12.2)
05000311/2005004-04	NCV	2A Emergency Diesel Generator Inoperable due to Operator Procedure Error (Section 1R22)
05000272/2005003-00	LER	ECCS Leakage Outside Containment Exceeds Dose Analysis Limits (Seal Injection Filter Replacement) (Section 4OA3.1)

05000272/2005002-00	LER	Technical Specification 3.03 Required Plant Shutdown - Sample Line Leak (Section 4OA3.3)
05000311/2005004-00	LER	Required Post Maintenance Testing Not Performed on Containment Isolation Valves (Section 4OA3.2)
05000311/2005002-00	LER	Reactor Coolant Instrument Line Through-Wall Leak (Section 4OA3.4)

LIST OF DOCUMENTS REVIEWED

In addition to the documents identified in the body of this report, the inspectors reviewed the following documents and records:

Section 1R04: Equipment Alignment

Procedures

S1.OP-SO.FO-0001, Emergency Diesel Fuel Oil System Operation
S1.OP-SO.RHR-0002, Terminating RHR
S1.OP-ST.SJ-0009, Emergency Core Cooling ECCS Subsystems Tavg >350F
SH.OP-AP.ZZ-0103, Component Configuration Control
S1.OP-SO.CC-0002, Component Cooling Heat Exchanger Operation
S1.OP-SO.DG-0001, 1A Diesel Generator Operation
S1.OP-SO.DG-0002, 1B Diesel Generator Operation
S1.OP-SO.4KV-0001, 1A 4Kv Vital Bus Operation
S1.OP-SO.4kV-0002, 1B 4Kv Vital Bus Operation
Unit 1 RHR Mechanical System Lineup (Lineup ID 807)

Drawings

205232 A 8761-36
205232 A 8761-35

Notifications

20248318, 20240172, 20243184, 20243185, 20238804, 20238505, 20238805, 20238674, 20238387, 20238806, 20238166, 20237281, 20235683, 20230295, 20235685, 20237150, 20237149, 20229082, 20206903, 20202265, 20201860, 20177520, 20177561, 20165101, 20165028, 20164941, 20234860, 20235846

Section 1R05: Fire Protection

Pre-Fire Plans

Salem - Unit 1, (Unit 2) Pre-Fire Plan FRS-II-444 Demineralized Ion Exchanger Area
Salem - Unit 1, (Unit 2) Pre-Fire Plan FRS-II-411 Reactor Plant Auxiliary Equipment Area
Salem - Unit 1, (Unit 2) Pre-Fire Plan FRS-II-511 Electrical Penetration Area
Salem - Unit 1, (Unit 2) Pre-Fire Plan FRS-II-512 Mechanical Penetration Area
Salem - Unit 1, (Unit 2) Pre-Fire Plan FRS-II-911 Service Water Intake Structure

Section 1R06: Flood Protection Measures

Procedures

SC.OP-AB.ZZ-0001, Adverse Environmental Conditions
SC.MD-PM.ZZ-0036, Watertight Door Inspection and Repair
SC.FP-SV.FBR-0026, Flood and Fire Barrier Penetration Seal Inspection

Orders

70013154, 80068497, 70049381

Notifications

20191373, 20211977, 20089862, 20247358

Other Documents

Salem Updated Final Safety Analysis Report
Salem Technical Specifications section 3.7.5.1
Salem Individual Plant Examination of External Events

Section 1R11: Licensed Operator Requalification Program

Procedures

S2.OP-AB.NIS-0001, Nuclear Instrument System Malfunction
S2.OP-AB.COND-0001, Loss of Condenser Vacuum
S2.OP-AB.RCP-0001, Reactor Coolant Pump Abnormality
S2.OP-AB.RC-0001, Reactor Coolant System Leak
S2.OP-AB.SW-0001, Loss of Service Water System Operations
2-EOP-TRIP-1, Reactor Trip or Safety Injection
2-EOP-TRIP-3, Safety Injection Termination
2-EOP-LOCA-1, Loss of Reactor Coolant
2-EOP-LOCA-3, Transfer to Cold Leg Recirculation
2-EOP-SGTR-1, Steam Generator Tube Rupture
2-EOP-SGTR-3, SGTR with LOCA - Subcooled Recovery

Other Documents

Simulator Training Scenario RSG-062
Simulator Examination Scenario Guide ESG-6
Simulator Examination Scenario Guide ESG LOR036/1
Salem Event Classification Guide
Salem Generating Station Technical Specifications Unit 2

Section 1R12: Maintenance Implementation

Procedures

SC.OP-SO.CA-0001, SBO Diesel Control Air Compressor
SC.OP-PT.CA-0001, SBO Diesel Control Air Compressor Test
SC.ER-DG.ZZ-0002, System Function Level Maintenance Rule Scoping Vs Risk Reference
SC.SS-ST.FP-0003, Diesel Fire Pump and SBO Air Compressor Batteries Surveillance Testing and Preventative Maintenance.
S1.OP-AB.CA-0001, Loss of Control Air
1-EOP-LOPA-1, Loss of All AC Power
2-EOP-LOPA-1, Loss of All AC Power
S1.OP-SO.CVC-0023, CVCS Cross-Connect Alignment to Unit 1
S2.OP-SO.CVC-0023, CVCS Cross-Connect Alignment to Unit 2
S1.OP-AB.LOOP-0001, Loss of Off-Site Power
S2.OP-AB.LOOP-0001, Loss of Off-Site Power
S1.OP-AB.SW-0005, Loss of All Service Water
S2.OP-AB.SW-0005, Loss of All Service Water
S1.OP-AB.CVC-0001, Loss of Charging
S2.OP-AB.CVC-0001, Loss of Charging
S1.OP-AB.RCP-0001, RCP Abnormality
S2.OP-AB.RCP-0001, RCP Abnormality
S1.OP-AB.CR-0002, Control Room Evacuation Due to Fire In Control Room, Relay Room, 460/230V Switchgear Room, or 4kV Switchgear Room
S2.OP-AB.CR-0002, Control Room Evacuation Due to Fire In Control Room, Relay Room, 460/230V Switchgear Room, or 4kV Switchgear Room

Notifications

20249774, 20218620, 20250272, 20249910, 20226858, 20192889, 20225683, 20226619, 20229514, 20229513, 20216063, 20253052, 20253019, 20253153, 20165852, 20191176, 20254207

Orders

70049537, 70050004, 70049537, 70049188, 70045343, 70039915, 70043159, 80080749, 70046052, 80029150

Other Documents

Salem System Health Report Control Air System, 2nd Quarter, 2005
VTD 316472, Gardner-Denver Portable Compressor Operator and Maintenance Manual
VTD 316754, Operation & Maintenance Manual 3304 and 3306 Industrial and Generator Set Engines
Salem Generating Station UFSAR Section 9.3.1
SORC Meeting Minutes from March 1, 2005

Section 1R13: Maintenance Risk Assessments and Emergent Work Control

Notifications

20251278, 20250530, 20250727, 20250605, 20153697, 20250527, 20250500, 20250621, 20250549, 20249871, 20249910, 20249894, 20249893, 20249774

Orders

60038329, 70032780, 70049921, 60057022, 80084186

Procedures

SH.OP-AP.ZZ-0027, Online Risk Assessment
SC.OP-PT.CA-0001, SBO Diesel Control Air Compressor Test

Drawings

223684 B 9790-31
223683 B 9790-21
223682 B 9790-7
223686 B 9790-24

Other Documents

Completed Salem Generating Station Weekly Risk Evaluation Forms
Regulatory Guide 1.182, Assessing and Managing Risk Before Maintenance Activities at Nuclear Power Plants

Section 1R15: Operability Evaluations

Procedures

SC.OP-PT.CA-0001, SBO Diesel Control Air Compressor Test
S1.OP-ST.DG-0001, 1A Diesel Generator Surveillance Test
SH.OP-AP.ZZ-0108, Operability Assessment and Equipment Control Program

Notifications

20103528, 20110007, 20112898, 20152865, 20250868, 20248002

Orders

70032693, 80084186, 70050181, 70049547

Section 1R19: Post-Maintenance Testing

Procedures

S2.OP-ST.SW-0005, Inservice testing - 25 Service Water Pump
SC.MD-PM.SW-0001, Service Water Rubber Expansion Joint Maintenance
S1.OP-ST.CC-0001, Inservice Testing - 11 Component Cooling Pump
SC.MD-CM.DG-0002, Emergency Diesel Generator Cylinder Head Replacement
SH.MD-AP.ZZ-0002, Maintenance Department Troubleshoot and Repair
SC.IC-GP.ZZ-0003, General Instrument Calibration Procedure for Field Devices

Notifications

20250236, 20251278, 20250530, 20250727, 20250605, 20153697, 20249889

Orders

30125673, 60056965, 60038329, 70032780, 50087216, 30121436, 30002874, 30098912, 80084525, 60057105

Section 1R22: Surveillance Testing

Procedures

2A Diesel Generator Surveillance Test, S2.OP-ST.DG-0001
S1.OP-ST.CC-0001, Inservice Testing - 11 Component Cooling Pump
SC.RA-IS.ZZ-0007, Exercised Closed Verification of Check Valves by Radiography
SH.RA-SP.ZZ-0105, Radiography of Valves and Components
S1.OP-ST.AF-0001, Inservice Testing - 11 Auxiliary Feedwater Pump
S1.RA-ST.AF-0001, Inservice Testing 11 Auxiliary Feedwater Pump Acceptance Criteria
S1.OP-ST.CVC-0004, Inservice Testing - 12 Charging Pump
S1.RA-ST.CVC-0004, Inservice Testing 12 Charging Pump Acceptance Criteria

Notifications

20250244, 20245524

Orders

50086088, 70049105, 80022588

Other Documents

Salem Unit One Control Room Logs dated July 5, 2005.

Section 1EP6 Drill Evaluation

Procedures

S2.OP-AB.RC-0001, Reactor Coolant System Leak
2-EOP-TRIP-1, Reactor Trip or Safety Injection
2-EOP-LOCA-1, Loss of Reactor Coolant
2-EOP-LOCA-3, Transfer to Cold Leg Recirculation

Other Documents

Simulator Examination Scenario Guide ESG-6
Salem Event Classification Guide
Salem Generating Station Technical Specifications Unit 2

Section 4OA2: Identification and Resolution of Problems

Procedures

BO-AA-15, Rev. 2, Exelon Nuclear Project Evaluation and Authorization Process
BO-AA-1004, Rev. 2, Exelon Nuclear Project Review Committee
NC.CA-DG.ZZ-0102, Rev. 0, Operational and Technical Decision Making Process Desk Guide,
NC.CA-DG.ZZ-0103, Rev. 1, Adverse Condition Monitoring and Contingency Planning, dated
NC.DE-DG.ZZ-0010, Engineering Change Package Quality
SH.SE-AS.ZZ-0001(Z), Rev. 0, Site Engineering Technical Evaluations, dated June 17, 2005
SH.OP-AP.ZZ-0108(Q)-Revision 19; Operability Assessment And Equipment Control Program, 9/2/05

Orders

80048294, 80057548, 80082541, 80045600, 80067634 20236180, 20236897, 20236946, 20236085, 20236251, 20236206, 20236205, 20236279, 20236501, 20236388, 20237123, 20234600, 20237296, 20237373, 20236737, 20237164, 20237161, 20234645, 20237348, 20237295, 20231322, 20236889, 20239528, 20236993, 20236890, 20236776, 20236995, 20236992, 20234255, 20237255, 20237134, 20237162, 20236889, 20255323

Other Documents

"PSEG Metrics for Improving the Work Environment, Salem and Hope Creek Generating Stations, Quarterly Report," dated July 29, 2005
Business Plan Performance Reports (August 2005) for Salem and Hope Creek
Engineering Department Performance Indicators dated September 2005
Engineering Response Team Turnovers dated 9/19 & 9/20/2005
Hope Creek 2nd Quarter 2005 System Health Reports for Turbine Building Chilled Water, Auxiliary Building Control Area Chilled Water, Main Steam and Service Water
Integrated Site Implementation Schedule
NRC / PSEG Nuclear Engineering Status Updates for Salem & Hope Creek dated September 19, 2005
Operational Challenges Response Checklists dated 8/22/05, 8/28/05 & 9/16/05.
Safety Conscious Work Environment Report dated June 2005
Salem / Hope Creek Organization Charts dated September 1, 2005
Salem 2nd Quarter 2005 System Health Reports for Control & Station Air, Circulating Water (Unit -1), Service Water (U-1&2), Radiation Monitoring (U-1&2), Chemical and Volume Control (U-1&2), Reactor Coolant (U-2), Chilled Water (U-2) and the Auxiliary Feedwater System (U-2)
S-C-AC-MEE-1923, Rev. 0, 10 CFR 50.59 Evaluation Related to TS Amendments 264 & 246, dated 8/21/2005

LIST OF ACRONYMS

ASME	American Society of Mechanical Engineers
CC	Component Cooling
CFCU	Containment Fan Cooling Unit
CIV	Containment Isolation Valve
CVCS	Chemical Volume and Control System
ECCS	Emergency Core Cooling System
EDG	Emergency Diesel Generator
ERT	Engineering Response Team
IMC	Inspection Manual Chapter
IPEEE	Individual Plant Examination For External Events
JPMs	Job Performance Measures
LBLOCA	Large Break Loss-of-Coolant Accident
LER	Licensee Event Report
LLRT	Local Leak Rate Test
MCIP	Material Condition Improvement Program
MR	Maintenance Rule
NCV	Non-cited Violation
NRC	Nuclear Regulatory Commission
OTDM	Operational and Technical Decision-Making
PARS	Publicly Available Records
PDP	Positive Displacement Pump
PI	Performance Indicator
PM	Preventive Maintenance

PMT	Post Maintenance Test
PSEG	Public Service Electric Gas
PT	Pressure Transmitter
QRT	Quality Review Team
RHR	Residual Heat Removal
SBOAC	Station Black-Out Air Compressor
SCWE	Safety Conscious Work Environment
SDP	Significance Determination Process
SRA	Senior Reactor Analyst
UFSAR	Updated Final Safety Analysis Report
ÎCDF	Core Damage Frequency
ÎLERF	Large Early Release Frequency