May 12, 2005

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

SUBJECT: SALEM NUCLEAR GENERATING STATION - NRC INTEGRATED INSPECTION REPORT 05000272/2005002 and 05000311/2005002

Dear Mr. Levis:

On March 31, 2005, the US Nuclear Regulatory Commission (NRC) completed an inspection at your Salem 1 & 2 reactor facilities. The enclosed integrated inspection report documents the inspection findings, which were discussed on April 1, 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.

This report documents two self-revealing findings of very low safety significance (Green). Both of these findings were determined to involve violations of NRC requirements. However, because of the very low safety significance and because they are entered into your corrective action program, the NRC is treating these two findings as non-cited violations (NCVs) consistent with Section VI.A of the NRC Enforcement Policy. If you contest any NCV in this report, you should provide a response within 30 days of the date of this inspection report, with the basis for your denial, to the Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington, DC 20555-0001; with copies to the Regional Administrator, Region I; the Director, Office of Enforcement, 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 05000272/2005002 and 05000311/2005002
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:	05000272/2005002, 05000311/2005002
Licensee:	PSEG Nuclear LLC
Facility:	Salem Nuclear Generating Station, Units 1 & 2
Location:	P.O. Box 236 Hancocks Bridge, NJ 08038
Dates:	January 1 - March 31, 2005
Inspectors:	J. Daniel Orr, Senior Resident Inspector George J. Malone, Resident Inspector Larry L. Scholl, Senior Reactor Inspector Joseph T. Furia, Senior Health Physicist Gordon Hunegs, Senior Resident Inspector David Kern, Senior Resident Inspector J. Wiebe, Project Engineer S. Barber, Senior Project Engineer
Approved By:	Eugene W. Cobey, Chief Projects Branch 3 Division of Reactor Projects

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SUMMARY OF FINDINGS

IR 05000272/2005002, 05000311/2005002; 01/01/2005 - 03/31/2005; Public Service Enterprise Group (PSEG) Nuclear LLC, Salem Units 1 and 2; Operator Performance During Non-routine Plant Evolutions and Events, and Other Activities.

The report covered a 13-week period of inspection by resident inspectors, reactor inspectors, and an announced inspection by a regional radiation specialist. Two Green non-cited violations (NCVs) 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 non-cited violation was identified when the 11 steam generator steam flow protection channel 1 instrument failed downscale due to an open instrument equalizing valve. The equalizing valve was left partially open at the conclusion of calibration activities contrary to procedure requirements. This finding was determined to be a non-cited violation of 10 CFR 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings."

  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 of the mitigating systems cornerstone and affected the objective to ensure the reliability of systems that respond to initiating events to prevent undesirable consequences. The inspectors determined that the finding was of very low safety significance (Green) using a Phase 1 screening in Appendix A of Inspection Manual Chapter 0609, "Determining the Significance of Reactor Inspection Findings for At-Power Situations." The finding was considered to not represent the actual loss of a safety function of a single train for greater than its Technical Specification allowed outage time, because only one instrument in engineered safety feature (ESF) channel 1 was affected. The 11 steam generator steam line flow channel 2 remained operable as well as other channel 1 ESF signals from low pressurizer pressure, steam line differential pressure, and containment high-high pressure. The finding was also not a design or qualification deficiency that resulted in a loss of function, did not result in an actual loss of safety function, and was not screened as potentially risk significant from external events. The performance deficiency had a human performance (personnel) cross cutting aspect. (Section 1R14)

- Green. A self-revealing, non-cited violation was identified on October 16, 2004, when the 13 auxiliary feedwater pump steam admission valve (1MS132) position indication malfunctioned and the valve stem rotated. Inadequate problem evaluation resulted in recurrent 1MS132 valve issues and the 13 auxiliary feedwater (AFW) pump being unnecessarily unavailable in July 2004 and October 2004. Specifically, the 1MS132 had exhibited stem rotation on three previous occasions, and PSEG did not evaluate the root cause of the valve rotational forces. PSEG also did not evaluate a loose actuator stem nut in July 2004. This finding was determined to be a non-cited violation of 10 CFR 50, Appendix B, Criterion XVI, "Corrective Action."

  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 of the mitigating systems cornerstone and affected the objective to ensure the availability of systems that respond to initiating events to prevent undesirable consequences. Senior Reactor Analysts determined that the finding was of very low safety significance (Green) using a Phase 3 analysis. The performance deficiency had a problem identification and resolution (evaluation) cross cutting aspect. (Section 4OA5.1)

B. Licensee Identified Violations

- None.

REPORT DETAILS

Summary of Plant Status

Unit 1 began the period at 100 percent (%) power and did not experience any downpowers greater than 20% for the entire inspection period.

Unit 2 began the period at 100% power and did not experience any downpowers greater than 20% for the entire inspection period.

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems and Barrier Integrity

1R02 Evaluations of Changes, Tests, or Experiments (71111.02)

a. Inspection Scope (7 safety evaluations and 19 safety evaluation screening samples)

The inspectors reviewed seven safety evaluations to verify that changes and tests were reviewed and documented in accordance with 10 CFR 50.59; and, when required, PSEG obtained NRC approval prior to implementation. The inspectors assessed the adequacy of the safety evaluations through interviews with PSEG personnel and review of supporting information, such as calculations, engineering analyses, design change documentation, the Updated Final Safety Analysis Report (UFSAR), Technical Specifications (TS) and plant drawings. In addition, the inspectors reviewed the administrative procedures that control the screening, preparation and issuance of the safety evaluations to ensure that procedures adequately implemented the requirements of 10 CFR 50.59, "Changes, Tests, and Experiments."

The inspectors also reviewed a sample of nineteen changes that PSEG had evaluated using a screening process and determined to be outside the scope of 10 CFR 50.59, therefore not requiring a full safety evaluation. The inspectors performed this review to assess PSEG's conclusions with respect to 10 CFR 50.59 applicability. A sample of issues not needing a full safety evaluation (design changes, procedure changes, UFSAR changes, temporary modifications, and a calculation revision) were reviewed.

The inspectors also reviewed issues that had been entered into the corrective action program to determine if PSEG had been effective in identifying problems associated with the 10 CFR 50.59 safety evaluation process. A sample of these issues were selected for additional review to assess the adequacy of the corrective actions which had been implemented.

The safety evaluations and screenings were selected based on the safety significance of the affected structures, systems, and components (SSCs). A listing of the safety evaluations, safety evaluation screenings, and other documents reviewed are listed in the Supplemental Information attachment to this report.

On August 23, 2004, the NRC's Executive Director for Operations approved a deviation from the NRC's Action Matrix to provide a greater level of oversight for the Salem station than would typically be called for in the Action Matrix. One provision of the deviation memorandum provided for the enhancement of existing reactor oversight process baseline inspections. In accordance with this deviation, the inspectors reviewed notifications 20176947, 20177118, and 20198289, related to problems associated with the 10 CFR 50.59 safety evaluation process. The notifications were reviewed to determine if the issues could result in an impact to the operation of the plant. The completed and planned corrective actions were also reviewed to determine if the problems were being addressed in an appropriate time frame.

b. Findings

No findings of significance were identified.

1R04 Equipment Alignment (71111.04)

a. Inspection Scope (3 partial walkdown samples and 1 complete walkdown)

Partial System Alignments. The inspectors performed a partial equipment alignment verification on the 12 residual heat removal train during a planned 11 residual heat removal train maintenance outage on February 1, 2005. The inspectors also performed a partial equipment alignment verification on the Salem Unit 1 and Unit 2 component cooling water systems while the station blackout air compressor was out of service on March 2, 2005. Component cooling water was risk significant as a support system for control air to both Salem Units. Finally, the inspectors performed a partial equipment alignment verification on the Salem 1 and Salem 2 hot shutdown panels on March 1, 2005. Partial equipment alignments were performed to verify the operability of redundant equipment during maintenance and for the case of hot shutdown panels to verify alignment of a risk important system not normally operated. Documents reviewed are listed in the Supplemental Information attachment to this report.

On August 23, 2004, the NRC's Executive Director for Operations approved a deviation from the NRC's Action Matrix to provide a greater level of oversight for the Salem station than would typically be called for by the Action Matrix. One provision of the deviation memorandum provided for the enhancement of existing reactor oversight process baseline inspections. In accordance with this deviation, the following additional inspection samples were performed. The inspectors reviewed corrective action program notifications, work orders, and evaluations associated with foreign material found in the auxiliary feedwater system to ensure PSEG adequately evaluated and corrected the associated conditions. These documents were 20185452, 20185952, 20186185, 60044562, 70038442, and 70038531. The inspectors also reviewed corrective action program notifications associated with a discrepancy between the amount of aluminum in containment and that which is listed in the Updated Final Safety Analysis Report. Finally, the inspectors reviewed notifications related to residual heat removal motor-operated valve wiring not configured in accordance with engineering drawings. The notifications reviewed were 20216590 and 20101522.

Complete System Alignment. During the weeks of February 7 and February 21, 2005, the inspectors performed one complete alignment check on the Unit 1 and Unit 2 auxiliary feedwater (AFW) systems to verify that the systems were properly configured, hangers and supports correctly installed and functional, and to identify any discrepancies between the existing lineup and the prescribed lineup, including locked valves. The inspectors interviewed the system engineer and reviewed corrective action evaluations associated with pump bearing oil issues and 22 AFW pump packing issues. The documents reviewed are 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 (9 samples)

The inspectors walked down eight fire areas and evaluated the adequacy of combustible material control, fire detection and suppression equipment availability and compensatory measures. The inspectors referenced Salem's pre-fire plans and NC.DE-PS.ZZ-0001-A6-GEN, "Programmatic Standard Salem Fire Protection Report-General." The inspectors reviewed applicable documents as listed in the Supplemental Information attachment to this report. The following plant areas were inspected:

- Unit 1 and Unit 2 relay rooms and associated battery rooms and corridor;
- Unit 1 and Unit 2 electrical penetration area;
- Unit 1 and Unit 2 460 volt and 230 volt switchgear rooms; and
- Unit 1 and Unit 2 4160 volt switchgear rooms.

The electrical penetration areas and the switchgear rooms were selected for walkdown, as a carbon dioxide migration issue required PSEG to initially disable all carbon dioxide suppression capability on January 26, 2005. The carbon dioxide migration issue was reported to the NRC in licensee event report (LER) 05000272/2005001-00, "Carbon Dioxide Migration Impacts Ability to Perform Safe Shutdown in the Event of a Fire," dated February 9, 2005.

On August 23, 2004, the NRC's Executive Director for Operations approved a deviation from the NRC's Action Matrix to provide a greater level of oversight for the Salem station than would typically be called for by the Action Matrix. One provision of the deviation memorandum provided for the enhancement of existing reactor oversight process baseline inspections. In accordance with this deviation, the following additional sample was performed. The inspectors reviewed notifications 20159777 and 20206944 related to inoperable fire doors identified during fire system walkdowns and an issue associated with finding moisture in halon fire suppression system piping.

b. Findings

No findings of significance were identified.

1R11 Licensed Operator Requalification Program (71111.11)

a. Inspection Scope (1 sample)

The resident inspectors observed a simulator training scenario on mitigation of small reactor coolant system (RCS) leaks, loss of circulating water, and loss of secondary heat sink to assess operator performance and training effectiveness. The scenario involved power operation at 100% with a small RCS leak developing in containment. A subsequent loss of two circulating pumps caused a plant downpower. The RCS leakage was increased as the plant was reduced in power. A break in the 21 steam generating feed line caused the reactor to be tripped with the turbine failing to trip and the crew unable to close main steam isolation valves. The crew then lost all ability to send water to the steam generators. The scenario concluded with a loss of offsite power. The inspectors verified operator actions were consistent with operating, alarm response, abnormal, and emergency procedures. The inspectors assessed simulator fidelity and verified that evaluators identified deficient operator performance where appropriate. Documents reviewed to verify proper operator performance and training effectiveness are listed in the Supplemental Information attachment to this report.

On August 23, 2004, the NRC's Executive Director for Operations approved a deviation from the NRC's Action Matrix to provide a greater level of oversight for the Salem station than would typically be called for by the Action Matrix. One provision of the deviation memorandum provided for the enhancement of existing reactor oversight process baseline inspections. In accordance with this deviation, the following additional sample was performed. The inspectors reviewed notifications 20208127, 20208171, and 20208202 associated with operations and maintenance training issues associated with a trip of the 13 auxiliary feed pump and human error traps found in emergency operations procedures.

b. Findings

No findings of significance were identified.

1R12 Maintenance Implementation (71111.12)

a. Inspection Scope (3 samples)

The inspectors performed three maintenance effectiveness inspections using the function-oriented approach to select risk significant systems: Salem Unit 1 component cooling water, Salem Unit 1 460 volt/ 230 volt alternating current (AC), and Salem Unit 2 460 volt/ 230 volt AC. The inspectors reviewed corrective action program notifications documenting past operating problems, system health reports, maintenance rule performance criteria, and interviewed system engineers and maintenance rule program coordinators. The inspectors performed the reviews to determine if PSEG had effectively characterized system performance. The inspectors referenced 10 CFR 50.65, “Requirements for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants,” and NUMARC 93-01, “Industry Guideline for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants,” to ascertain the acceptability of PSEG’s maintenance rule application. The inspectors also walked down a majority of system components and reviewed maintenance reports to verify adequate material condition. Additional documents are listed in the Supplemental Information attachment to this report.

On August 23, 2004, the NRC’s Executive Director for Operations approved a deviation from the NRC’s Action Matrix to provide a greater level of oversight for the Salem station than would typically be called for by the Action Matrix. One provision of the deviation memorandum provided for the enhancement of existing reactor oversight process baseline inspections. In accordance with this deviation, the following additional sample was performed. The inspectors reviewed notification 20213580 and condition report 70043077 associated with the 25 service water pump exceeding its maintenance rule unavailability goal.

b. Findings

No findings of significance were identified.

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

a. Inspection Scope (6 samples)

The inspectors reviewed PSEG’s planning and risk assessments for six risk significant activities. The inspectors reviewed control room operating logs and PSEG probabilistic safety assessment risk evaluation forms, walked down protected equipment and maintenance locations, and interviewed involved personnel. These reviews were performed to determine whether PSEG properly assessed and managed plant risk and performed activities in accordance with applicable Technical Specification and work control requirements. The activities selected were based on plant maintenance schedules and systems that contributed to plant risk. The inspectors also referenced Regulatory Guide 1.182, “Assessing and Managing Risk Before Maintenance Activities at Nuclear Power Plants,” and PSEG procedure SH.OP-AP.ZZ-0027, “On-Line Risk Assessment.” The following plant configurations were inspected:

- Emergent maintenance for the 21 and 22 control room chilled water compressors on January 2, 2005;
- Planned unavailability for the 22 switchgear ventilation exhaust fan and the 2B emergency diesel generator on February 8, 2005;
- Emergent unavailability of the 11 component cooling water heat exchanger for flow instrument calibrations on February 19, 2005;
- Emergent unavailability of the 22 residual heat removal heat exchanger due to a malfunction of the 22CC16 motor operated valve on February 23, 2005;

- Planned unavailabilities of the 11 diesel fuel oil transfer pump, 11 component cooling water pump, and 11 component cooling water pump area room cooler on March 3, 2005; and
- Planned unavailability for the Number 2 Emergency Control Air Compressor on March 14, 2005.

On August 23, 2004, the NRC's Executive Director for Operations approved a deviation from the NRC's Action Matrix to provide a greater level of oversight for the Salem station than would typically be called for by the Action Matrix. One provision of the deviation memorandum provided for the enhancement of existing reactor oversight process baseline inspections. In accordance with this deviation, the following additional inspection sample was performed. The inspectors reviewed corrective action program notifications 20226093, 20224260, and 20216858, which identified risk assessment problems, to ensure they were adequately evaluated and corrected.

b. Findings

No findings of significance were identified.

1R14 Operator Performance During Non-routine Evolutions and Events (71111.14)

a. Inspection Scope (2 samples)

The inspectors reviewed the personnel performance issue involved with an inoperable 11 steam generator steam line flow channel 1 instrument that was identified on December 16, 2004, during a Unit 1 power ascension. The inspectors reviewed the personnel issues to understand if control room operators identified the instrument anomaly in a timely fashion and complied with Technical Specification requirements. The inspectors also examined the corrective action evaluation and proposed corrective actions.

The inspectors observed main control room operators and reactor engineers perform an end-of-life moderator temperature coefficient measurement on February 17, 2005. The inspectors attended the pre-job brief on February 16, 2005. Salem procedure SC.RE-ST.ZZ-0007, "Moderator Temperature Coefficient Measurement," was used by control room operators and engineers as a method for performing the Technical Specification requirement and was referenced by the NRC inspectors. The inspectors also reviewed notification 20225447 that was initiated following the test to suggest procedure enhancements.

On August 23, 2004, the NRC's Executive Director for Operations approved a deviation from the NRC's Action Matrix to provide a greater level of oversight for the Salem station than would typically be called for by the Action Matrix. One provision of the deviation memorandum provided for the enhancement of existing reactor oversight process baseline inspections. In accordance with this deviation, the following additional inspection sample was performed. The inspectors reviewed corrective action program notifications identifying human performance issues to ensure they were adequately evaluated and corrected. The additional notifications reviewed are listed in the Supplemental Information attachment to this report.

b. Findings

Introduction. A Green self-revealing non-cited violation was identified when the 11 steam generator steam flow protection channel 1 instrument failed downscale due to an open instrument equalizing valve. The equalizing valve was left partially open at the conclusion of calibration activities contrary to procedure requirements. This finding was determined to be a non-cited violation of 10 CFR 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings."

Description. On December 16, 2004, control room operators performed a control board walkdown during a reactor power increase. The operators observed that the 11 steam generator steam line flow channel 1 instrument was reading approximately 10% while channel 2 and all other steam generator channels were reading approximately 26%. About 7 hours elapsed during the power ascension from 10% power to 26% power when the discrepant instrument was identified. PSEG initiated troubleshooting activities to resolve the discrepant instrument indication. Operators and maintenance technicians immediately placed the failed steam line flow instrument bistable in a tripped condition.

PSEG troubleshooting identified that the instrument transmitter equalizing valve was slightly open. Further investigation determined that the transmitter was last worked on December 8, 2004, to perform a sensor calibration. Salem Unit 1 was in hot shutdown conditions when the transmitter was returned to service. Instrument and calibration (I&C) procedure S1.IC-SC.RCP-0028, "1FT-512 #11 Steam Generator Steam Flow Protection Channel I," provided detailed work instructions to properly return the instrument to service. The procedure also required independent verification of the closed equalizing valve.

PSEG's evaluation of this issue (order 70043812) concluded that the transmitter equalizing valve was not properly closed on December 8, 2004. The inspectors judged that the control room operators identified the failed instrument in a timely fashion and took prompt action consistent with TS requirements.

Analysis. A noncompliance with TS 3.3.2.1, "Engineered Safety Feature Actuation System Instrumentation," occurred when Salem Unit 1 entered hot standby conditions, mode 3, or reactor coolant temperature above 350EF at 4:47 p.m. on December 14, 2004. The residual heat removal system was secured at 11:27 p.m. on December 13, 2004. The failed instrument was placed in a tripped condition at 6:13 p.m. on December 16, 2004, and TS compliance was restored.

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 of the mitigating systems cornerstone and affected the objective to ensure the availability of systems that respond to initiating events to prevent undesirable consequences. The engineered safety feature actuation systems is a mitigating system that initiates safety injection or containment isolations automatically from various vital instrument signals. The steam line flow instruments have two safety functions: to initiate safety injection and to initiate main steam line isolation for steam line breaks. In addition to redundant steam line flow channels, the safety injection initiation is backed by low pressurizer pressure and steam line differential pressure signals. The main steam line isolation is backed by containment high-high pressure signals. The inspectors determined that the finding was of very low safety significance (Green) using a Phase 1 screening in Appendix A of Inspection Manual Chapter 0609, "Determining the Significance of Reactor Inspection Findings for At-Power Situations." This finding was considered to not represent the actual loss of a safety function of a single train for greater than its Technical Specification allowed outage time, because only one instrument in engineered safety feature (ESF) channel 1 was affected. The 11 steam generator steam line flow channel 2 remained operable as well as other channel 1 ESF signals for low pressurizer pressure, steam line differential pressure, and containment high-high pressure. The finding was also not a design or qualification deficiency that resulted in a loss of function, did not result in an actual loss of safety function, and was not screened as potentially risk significant from external events.

The performance deficiency had a human performance cross cutting aspect (personnel) and involved a failure to comply with maintenance procedure requirements. Detailed procedure instructions to close and independently verify closed an instrument equalizing valve were not satisfactorily completed.

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 December 8, 2004, PSEG maintenance technicians failed to close the equalizing valve for the 11 steam generator steam line flow channel 1 instrument during restoration activities which was not in accordance with S1.IC-SC.RCP-0028, "1FT-512 #11 Steam Generator Steam Flow Protection Channel I." However, because the finding was of very low significance and has been entered into PSEG's corrective action program (notification 20216735), this finding is being treated as a non-cited violation, consistent with section VI.A of the NRC Enforcement Policy. **(NCV 05000272/2005002-01, Maintenance Practices Render a Protection Instrument Inoperable)**

1R15 Operability Evaluations (71111.15)

a. Inspection Scope (4 samples)

The inspectors reviewed four operability determinations (ODs) and equipment issues. The reviews assessed technical adequacy, the use and control of compensatory measures, and compliance with the licensing and design basis. The inspectors' review included a verification that the operability determinations were made as specified by

PSEG's procedure SH.OP-AP.ZZ-0108, "Operability Assessment and Equipment Control Program." The technical content of the ODs and the follow-up operability assessments were reviewed and compared to applicable Technical Specifications, the Updated Final Safety Analysis Report, and associated design and licensing basis documents. The inspectors also interviewed operations management, design engineers, and system engineers. The following operability issues were reviewed:

- 14 and 24 steam generators auxiliary feedwater line potential back leakage (notifications 20223395 and 20223396);
- Salem Units 1 and 2 auxiliary building ventilation flow-balance not consistent with design requirements (notification 20226355);
- Salem Unit 2 1 of 2 pressurizer spray lines (2PS1) isolated for maintenance (tagout 4144943); and
- Increasing mechanical vibrations on the 12 charging pump speed increaser (notification 20222079).

On August 23, 2004, the NRC's Executive Director for Operations approved a deviation from the NRC's Action Matrix to provide a greater level of oversight for the Salem station than would typically be called for by the Action Matrix. One provision of the deviation memorandum provided for the enhancement of existing reactor oversight process baseline inspections. In accordance with this deviation, the following additional inspection sample was performed. The inspectors reviewed notification 20204060 and condition report 70041510 associated with a missed operability determination when a valve (11SW58) failed a stroke time test rendering the 11 CFCU inoperable.

b. Findings

No findings of significance were identified. However, the operability determination associated with the Unit 1 and Unit 2 auxiliary building ventilation flow-balance not being consistent with design requirements is unresolved pending further inspector review of PSEG's past operability determination. This issue is identified as **URI 05000272&311/2005002-02, Low Auxiliary Building Ventilation Flows.**

1R16 Operator Workarounds (71111.16)

a. Inspection Scope (2 samples)

The inspectors reviewed two operator workaround (OWA) conditions or potential OWAs to determine if the functional capability of the system was affected or human reliability in responding to initiating events was impacted. One OWA was associated with the 11 and 22 safety injection accumulators minor pressure loss and 12 safety injection accumulator minor level changes (notifications 20170100, 20200938, and 20200872). The second OWA was associated with an automatic malfunction of the 12 control room chiller compressor recirculating pump (notification 20228456).

On August 23, 2004, the NRC's Executive Director for Operations approved a deviation from the NRC's Action Matrix to provide a greater level of oversight for the Salem station than would typically be called for by the Action Matrix. One provision of the deviation memorandum provided for the enhancement of existing reactor oversight process baseline inspections. In accordance with this deviation, the following additional inspection sample was performed. The inspectors reviewed corrective action program notifications identifying operator workaround issues to ensure they were adequately evaluated and corrected. The additional notifications reviewed were 20197813, 20199775, 20207684, 20208126, and 20213777.

b. Findings

No findings of significance were identified.

1R17 Permanent Plant Modifications (71111.17)

a. Inspection Scope (8 samples)

Biennial Review. The inspectors reviewed selected permanent plant modification packages to verify that the design bases, licensing bases, and performance capability of risk significant SSCs had not been degraded through plant modifications.

Plant changes were selected for review based on risk insights for the plant. The inspectors performed walkdowns of selected plant systems and components, interviewed plant staff, and reviewed applicable documents, including procedures, calculations, modification packages, engineering evaluations, drawings, corrective action program documents, the UFSAR, and TSs.

The inspectors verified that selected attributes (component safety classification, energy requirements supplied by supporting systems, seismic qualification, instrument set-points, uncertainty calculations, electrical coordination, electrical loads analysis, and equipment environmental qualification) were consistent with the design and licensing bases. Design assumptions were reviewed to verify that they were technically appropriate and consistent with the UFSAR. For each modification, the 50.59 screenings or evaluations were reviewed as described in section 1R02 of this report. The inspectors verified that procedures, calculations, and the UFSAR were properly updated with revised design information and operating guidance. The inspectors also verified that the as-built configuration was accurately reflected in the design documentation and that post-modification testing was adequate to ensure the SSC would function properly.

The inspectors also reviewed issues that had been entered into the corrective action program to determine if PSEG had been effective in identifying problems associated with the plant modification process and activities. Samples of these issues were selected for further review during which the inspectors assessed the adequacy of the corrective actions which had been implemented for the selected issues. A listing of documents reviewed is provided in the Supplemental Information attachment to this report.

On August 23, 2004, the NRC's Executive Director for Operations approved a deviation from the NRC's Action Matrix to provide a greater level of oversight for the Salem station than would typically be called for in the Action Matrix. One provision of the deviation memorandum provided for the enhancement of existing reactor oversight process baseline inspections. In accordance with this deviation, the inspectors reviewed corrective action notifications 20213936, 20199121, and 20179360, related to problems associated with implementing permanent plant modifications. The completed and planned corrective actions were reviewed to determine if the problems were being addressed in an appropriate time frame.

b. Findings

No findings of significance were identified.

1R19 Post-Maintenance Testing (71111.19)

a. Inspection Scope (5 samples)

The inspectors observed portions of and reviewed documentation for post maintenance testing (PMT) associated with the following five work activities:

- 12 containment fan coil unit service water valve, 12SW58, replacement on February 10, 2005;
- 12 service water pump motor replacement on February 14, 2005;
- 25 containment fan coil unit service water valve, 25SW223, controls repair on February 23, 2005;
- 22 residual heat removal heat exchanger component cooling water outlet flow valve, 22CC16, torque switch repair on February 24, 2005; and
- Number 2 emergency control air compressor preventative maintenance on March 16, 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 operable status and ready to perform its safety function. Documents reviewed to verify post maintenance testing adequacy are listed in the Supplemental Information attachment to this report.

On August 23, 2004, the NRC's Executive Director for Operations approved a deviation from the NRC's Action Matrix to provide a greater level of oversight for the Salem station than would typically be called for by the Action Matrix. One provision of the deviation memorandum provided for the enhancement of existing reactor oversight process baseline inspections. In accordance with this deviation, the following additional inspection samples were performed. The inspectors reviewed notifications 20211008, 20211977, 20215016, and 20217060 to assess PSEG's recent corrective action program effectiveness for post maintenance testing issues.

b. Findings

No findings of significance were identified.

1R20 Refueling and Other Outage Activities (71111.20)

a. Inspection Scope (1 sample)

On March 15, 2005, the inspectors observed new fuel receipt inspections for four fuel assemblies in preparation for the April 2005 Unit 2 refueling outage, 2R14. Inspection activities included record reviews, interviews, and direct observation of new fuel inspection and fuel movement into the spent fuel pool to verify fuel met design features for fuel storage as described in TS, equipment and personnel were properly tested prior to handling new fuel, fuel was properly examined to verify no damage had occurred during shipment, and nuclear material accountability was properly maintained. The inspectors verified the evolution was performed according to work order 30094110, "New Fuel Receipt," and station procedures SC.RE-FR.ZZ-0001, "Fuel Handling," and SC.RE.FR.ZZ-0002, "New Fuel Receipt and Storage."

On August 23, 2004, the NRC's Executive Director for Operations approved a deviation from the NRC's Action Matrix to provide a greater level of oversight for the Salem station than would typically be called for by the Action Matrix. One provision of the deviation memorandum provided for the enhancement of existing reactor oversight process baseline inspections. In accordance with this deviation, the following additional inspection samples were performed. The inspectors reviewed notifications 20184105 and 20184229 involving human performance errors during the most recent refuel outage to assess PSEG's recent corrective action program effectiveness for outage issues.

b. Findings

No findings of significance were identified.

1R22 Surveillance Testing (71111.22)

a. Inspection Scope (6 samples)

The inspectors observed portions and/or reviewed results of the following six surveillance tests:

C S2.OP-ST.SJ-0001, "Inservice Testing - 21 Safety Injection Pump," on January 4, 2005;

- S1.OP-ST.CVC-0004, “Inservice Testing - 12 Charging Pump,” on January 10, 2005;
- S1.OP-ST.CC-0001, “Inservice Testing - 11 Component Cooling Pump,” on January 31, 2005;
- S2.IC-TR.RCP-0048, “2FT-532 #23 Steam Generator Steam Flow Protection Channel I Time Response Test,” and S2.IC-TR.RCP-0058, “2FT-542 #24 Steam Generator Steam Flow Protection Channel I Time Response Test,” on February 3, 2005;
- S1.OP-ST.AF-0004, “Inservice Testing - Auxiliary Feedwater Valves,” on February 8, 2005; and
- S2.OP-ST.DG-0002, “2B Diesel Generator Surveillance Test,” S2.OP-ST.DG-0013, “2B Diesel Generator Endurance Run,” and S2.OP-ST.DG-0020, “2B Diesel Generator Hot Restart Test,” performed on February 9, 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 TS requirements and the UFSAR.

On August 23, 2004, the NRC’s Executive Director for Operations approved a deviation from the NRC’s Action Matrix to provide a greater level of oversight for the Salem station than would typically be called for by the Action Matrix. One provision of the deviation memorandum provided for the enhancement of existing reactor oversight process baseline inspections. In accordance with this deviation, the following additional inspection samples were performed. The inspectors reviewed notification 20202234 involving a recent surveillance test issue to assess PSEG’s recent corrective action program effectiveness for surveillance testing issues.

b. Findings

No findings of significance were identified.

1R23 Temporary Plant Modifications (71111.23)

a. Inspection Scope (1 sample)

During a plant status walkdown on February 15, 2005, the NRC inspectors noted a tygon hose inserted into the containment building to the auxiliary building seismic gap cover in the Unit 1 78' elevation mechanical penetration area. The tygon hose had apparently been installed to collect groundwater that had become a housekeeping concern. The inspectors reviewed past notifications documenting the tygon hose. The inspectors also reviewed chemistry analysis results of the ground water and interviewed materials engineers regarding potential long term impacts on concrete integrity. Documents reviewed are listed in the Supplemental Information attachment to this report.

On August 23, 2004, the NRC’s Executive Director for Operations approved a deviation from the NRC’s Action Matrix to provide a greater level of oversight for the Salem station than would typically be called for by the Action Matrix. One provision of the deviation memorandum provided for the enhancement of existing reactor oversight process baseline inspections. In accordance with this deviation, the following additional inspection samples were performed. The inspectors reviewed notifications 20197822, 20198139, 20209659, and 20209660 involving a recent modification issues to assess PSEG's recent corrective action program effectiveness for modification issues.

b. Findings

No findings of significance were identified. However, the issue involving long term impacts on concrete integrity is unresolved. The chemistry results of the groundwater were similar to groundwater at the fuel handling building seismic gap, both including similar levels of boron. The boron is believed to be residual from the spent fuel pool leak to the fuel handling building seismic gap that ceased in February 2003. An existing unresolved item exists regarding structural integrity of the fuel handling building, URI 05000272/2003006-02. That URI is pending NRC review of a structural evaluation contracted by PSEG. This item is also unresolved pending NRC review of the same structural evaluation as it may apply to the containment building concrete and is identified as **URI 05000272/2005002-03, Ground Water Intrusion to the Auxiliary Building and Containment Building Seismic Gap**.

2. RADIATION SAFETY

Cornerstone: Occupational Radiation Safety [OS]

2OS1 Access Control to Radiologically Significant Areas (71121.01)

a. Inspection Scope (4 samples)

The inspectors identified exposure significant work areas within radiation areas, high radiation areas (<1 R/hr), or airborne radioactivity areas in the plant and reviewed associated PSEG controls and surveys of these areas to determine if controls (e.g. surveys, postings, barricades) were acceptable. The inspectors walked down these areas or their perimeters to determine: whether prescribed radiation work permit, procedure, and engineering controls were in place; whether PSEG surveys and postings were complete and accurate; and whether air samplers were properly located.

The inspectors examined PSEG's physical and programmatic controls for highly activated or contaminated non-fuel materials stored within spent fuel pools.

The inspectors reviewed radiological corrective action notifications since the last inspection that documented radiation protection technician errors. The inspectors determined if there was an observable pattern traceable to a similar cause and determined that this perspective matches the corrective action approach taken by PSEG to resolve those issues.

On August 23, 2004, the NRC's Executive Director for Operations approved a deviation from the NRC's Action Matrix to provide a greater level of oversight for the Salem station than would typically be called for by the Action Matrix. One provision of the deviation memorandum provided for the enhancement of existing reactor oversight process baseline inspections. In accordance with this deviation, the following additional inspection sample was performed. The inspectors reviewed corrective action program notifications 20219655 and 20219774. The inspectors validated that radiological access control issues were being resolved through notification reviews and discussions with the station radiation protection personnel.

b. Findings

No findings of significance were identified.

2OS2 ALARA Planning and Controls (71121.02)

a. Inspection Scope (2 samples)

The inspectors reviewed the assumptions and basis for the current annual collective exposure estimate, and reviewed applicable procedures to determine the methodology for estimating work activity-specific exposures and the intended dose outcome.

Utilizing PSEG records, the inspectors determined the historical trends and current status of tracked plant source terms, and determined that PSEG was making allowances and developed contingency plans for expected changes in the source term due to changes in plant fuel performance or changes in plant primary chemistry.

On August 23, 2004, the NRC's Executive Director for Operations approved a deviation from the NRC's Action Matrix to provide a greater level of oversight for the Salem station than would typically be called for by the Action Matrix. One provision of the deviation memorandum provided for the enhancement of existing reactor oversight process baseline inspections. In accordance with this deviation, the following additional inspection sample was performed. The inspectors reviewed corrective action program notifications 20020053, 20219461, and 20219282. The inspectors validated that as low as is reasonably achievable (ALARA) issues were being resolved through notification reviews and discussions with the station ALARA personnel.

b. Findings

No findings of significance were identified.

2OS3 Radiation Monitoring Instrumentation (71121.03)

a. Inspection Scope (1 sample)

The inspectors verified calibration, operability, and alarm setpoints of several types of instruments and equipment and determined what actions were taken when, during calibration or source checks, an instrument was found significantly out of calibration (>50%). The inspectors determined possible consequences of out of calibration instrument use since last successful calibration or source check and determined that any out of calibration results were entered into the corrective action program.

b. Findings

No findings of significance were identified.

Cornerstone: Public Radiation Safety [PS]

2PS1 Radioactive Gaseous and Liquid Effluent Treatment and Monitoring Systems (71122.01)

a. Inspection Scope (10 samples)

The inspectors reviewed the most current radiological effluent release report to verify that the program was implemented as described in "Radiological Effluent Technical Specification/Offsite Dose Calculation Manual" (RETS/ODCM); reviewed the report for significant changes to the ODCM and to radioactive waste system design and operation; determined whether the changes to the ODCM were made in accordance with Regulatory Guide 1.109, "Calculation of Annual Doses to Man From Routine Releases of Reactor Effluents for the Purpose of Evaluating Compliance With 10 CFR Part 50, Appendix I," and NUREG-0133, "Working Safety With Nuclear Gauges," and were technically justified and documented; determined whether the modifications made to radioactive waste system design and operation changed the dose consequence to the public; verified that technical and/or 10 CFR 50.59 reviews were performed when required; and, determined whether radioactive liquid and gaseous effluent radiation monitor setpoint calculation methodology changed since completion of the modifications. The inspectors determined that anomalous results reported in the current radiological effluent release report were adequately resolved. The inspectors reviewed RETS/ODCM to identify the effluent radiation monitoring systems and its flow measurement devices; reviewed effluent radiological occurrence performance indicator incidents for onsite follow-up; reviewed PSEG self assessments, audits, and licensee event reports (LERs) that involved unanticipated offsite releases of radioactive material; and, reviewed the UFSAR description of all radioactive waste systems.

The inspectors walked down the major components of the gaseous and liquid release systems (e.g., radiation and flow monitors, demineralizers and filters, tanks, and vessels) to observe current system configuration with respect to the description in the UFSAR, ongoing activities, and equipment material condition.

The inspectors observed the routine processing, including sample collection and analysis and release of radioactive liquid waste to verify that appropriate treatment equipment is used and that radioactive liquid waste is processed and released in accordance with procedure requirements. The inspectors observed the sampling and compositing of liquid effluent samples. In lieu of direct observation, the inspectors reviewed several radioactive liquid waste release permits, including the projected doses to members of the public. The inspectors also observed the routine processing, including sample collection and analysis, and release of radioactive gaseous effluent to verify that appropriate treatment equipment was used and that the radioactive gaseous effluent was processed and released in accordance with RETS/ODCM requirements.

The inspectors reviewed the records of any abnormal releases or releases made with inoperable effluent radiation monitors and reviewed PSEG's actions for these releases to ensure an adequate defense-in-depth was maintained against an unmonitored, unanticipated release of radioactive material to the environment.

The inspectors reviewed changes made by PSEG to the ODCM as well as to the liquid or gaseous radioactive waste system design, procedures, or operation since the last inspection. For each system modification and each ODCM revision that impacted effluent monitoring or release controls, the inspectors reviewed PSEG's technical justification and determined whether the changes affected PSEG's ability to maintain effluents ALARA and whether changes made to monitoring instrumentation resulted in a non-representative monitoring of effluents.

The inspectors reviewed a selection of monthly, quarterly, and annual dose calculations to ensure that PSEG had properly calculated the offsite dose from radiological effluent releases and to determine if any annual TS or ODCM (i.e., Appendix I to 10 CFR Part 50 values) requirements were exceeded and, if appropriate, a Performance Indicator (PI) report issued.

The inspectors reviewed air cleaning system surveillance test results and PSEG specific methodology to ensure that the system was operating within PSEG's acceptance criteria. The inspectors also reviewed surveillance test results and methodology that PSEG used to determine the stack and vent flow rates and verified that the flow rates were consistent with RETS/ODCM or UFSAR values.

The inspectors reviewed records of instrument calibrations performed since the last inspection for each point of discharge effluent radiation monitor and flow measurement device and reviewed any completed system modifications and the current effluent radiation monitor alarm setpoint value for agreement with RETS/ODCM requirements. The inspectors also reviewed calibration records of radiation measurement instrumentation associated with effluent monitoring and release activities and reviewed quality control records for the radiation measurement instruments.

The inspectors reviewed the results of the interlaboratory comparison program to verify the quality of radioactive effluent sample analyses performed by PSEG; reviewed PSEG's quality control evaluation of the interlaboratory comparison test and associated corrective actions for any deficiencies identified: and reviewed the results from PSEG's QA audits and determined that PSEG met the requirements of the RETS/ODCM.

The inspectors reviewed licensee event reports, special reports, audits, and self assessments related to the RETS/ODCM program performed since the last inspection. The inspectors determined that identified problems were entered into the corrective action program for resolution. The inspectors also reviewed corrective action program notifications affecting environmental sampling, sample analysis, or meteorological monitoring instrumentation.

On August 23, 2004, the NRC's Executive Director for Operations approved a deviation from the NRC's Action Matrix to provide a greater level of oversight for the Salem Station than would typically be called for by the Action Matrix. One provision of the deviation memorandum provided for the enhancement of existing reactor oversight process baseline inspections. In accordance with this deviation, the following additional inspection sample was performed. The inspectors reviewed corrective action program notifications 20218126, 20218840, 20219292, 20221002, 20221357, and 20223520. The inspectors validated that RETS issues were being resolved through notification reviews and discussions with the station chemistry and systems engineering personnel.

b. Findings

No findings of significance were identified.

4. OTHER ACTIVITIES [OA]

4OA2 Identification and Resolution of Problems (71152)

As required by Inspection Procedure 71152, "Identification and Resolution of Problems," and in order to 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 notification report, attending daily screening meetings, or accessing PSEG's computerized database.

On August 23, 2004, the NRC's Executive Director for Operations approved a deviation from the NRC's Action Matrix to provide a greater level of oversight for the Salem station than would typically be called for by the Action Matrix. One provision of the deviation memorandum provided for the enhancement of existing reactor oversight process baseline inspections. In accordance with this deviation, the following additional inspection samples were performed. The inspectors reviewed PSEG's Business Plan Initiative CAP.02.PS.01.01, "Enter/Verify in Corrective Action Program Corrective Actions From Self Assessments and Assists," and CAP.01.PS.02.02, "Assess Initial Senior Reactor Operator Operability Screening," to verify that adverse conditions were identified and entered into the corrective action program. The inspectors also reviewed progress in initiatives SCWE.01.OPS.02.14, "Review and revise as necessary training effecting the conduct of site activities, i.e., conduct of operations and maintenance, to ensure that the message of safety over production is consistently delivered across site programs," and SCWE.02.OPS.02.14, "Review all current problem identification processes, identify and discontinue any department specific problem reporting systems, ensure all problems identified through separately maintained systems are captured and processed in accordance with the site specific processes." The inspectors reviewed notification 20230806 related to PSEG business plan SCWE item progress. No findings of significance were identified.

2. Annual Sample Review

a. Inspection Scope (1 sample)

The inspectors reviewed PSEG evaluation 70043313 to ensure that corrective actions for an issue involving an 11 residual heat removal (RHR) heat exchanger head gasket leak on December 5, 2004, were appropriate. This issue was also described in LER 05000272/2004005-00 and section 4OA3 of this Inspection Report. This issue was selected for review to examine the quality of PSEG root cause evaluation on a risk significant component. The issue also potentially involved maintenance practices as a causal factor because the 11 RHR heat exchanger head gasket had been repaired in May 2004. The inspectors interviewed plant personnel involved in corrective action development and verified satisfactory completion of several corrective actions.

b. Findings and Observations

There were no findings of more than minor significance associated with this issue. The inspectors concluded that PSEG performed an adequate root cause analysis and established appropriate corrective actions.

2. Safety Conscious Work Environment Review

c. Inspection Scope

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

The inspectors conducted a sampling review of PSEG's actions to improve the work environment on February 15 through 17, 2005. During the inspection, a limited number of interviews with PSEG personnel and 32 SCWE performance indicators (PIs) from the fourth quarter of 2004 were reviewed to assess progress since the last quarterly review. In the fourth quarter 2004, PSEG identified 14 PIs as being green (satisfactory) while 15 were identified as red (needs improvement) compared to the third quarter 2004 when 17 PIs were identified as green and 12 PIs as red. The inspectors did not identify any discernable performance improvement from the third quarter to the fourth quarter of 2004.

The inspectors review of the fourth quarter 2004 PIs showed that certain individual PIs were red at both Hope Creek and Salem stations. The PIs in this category included repeat maintenance and emergency diesel generator unavailability. The auxiliary feedwater and chemical volume control/safety injection system unavailability PIs were red for both Salem units. The inspectors reviewed PSEG's corrective actions to improve performance in these areas and noted that PSEG was applying additional resources in those areas in an attempt to improve performance.

Discussions between the inspectors and PSEG personnel focused on uncertainty about how the management changes implemented under the January 17, 2005, Nuclear Operating Services Contract would affect the work environment. Specifically, PSEG personnel acknowledged questions about the continued effectiveness of previous commitments to address work environment issues such as the use of the "People Team" and the Executive Review Board (ERB) to review certain employment actions.

d. Findings

No findings of significance were identified.

3. Executive Review Board Commitments

a. Inspection Scope

On August 23, 2004, the NRC's Executive Director for Operations approved a deviation from the NRC's Action Matrix to provide a greater level of oversight for the Hope Creek station than would typically be called for by the Action Matrix. One provision of the deviation memorandum provided for the enhancement of existing reactor oversight process baseline inspections. In accordance with the deviation memorandum, the inspectors performed a review to evaluate the effect the Nuclear Operations Service Contract (NOSC) between Exelon and PSEG had on the work environment at Salem and Hope Creek stations. Specifically, the inspectors reviewed corrective action program notification 20221830 which documents a failure to implement the ERB process.

b. Findings

The failure to implement the ERB process is unresolved pending further review by NRC staff.

In a January 28, 2004 letter to PSEG, NRC published interim results from its review of work environment issues at the Salem and Hope Creek Generating Stations. During subsequent public meetings with the NRC in March and June 2004, PSEG described its plan to address the work environment issues at the stations. PSEG further described this plan and committed to taking a number of actions to improve the work environment at the stations in a June 25, 2004 letter to the NRC.

In that letter, PSEG stated that an ERB had been established to review PSEG and contractor personnel actions to preclude retaliation and/or chilling effect at the stations. This action was taken to improve management effectiveness in detecting and preventing retaliation and the creation of a chilling effect. In addition, in this letter PSEG committed to providing to the NRC, on a quarterly basis, selected performance metrics related to safety conscious work environment. These metrics include a metric on ERB effectiveness. On July 30, 2004, in a letter to PSEG, NRC published the final results from its review of work environment issues at the stations and acknowledged that PSEG's June 25, 2004 letter appeared to address the key findings of both the NRC and PSEG assessments.

In December 2004, PSEG announced that it had entered into a Nuclear Operating Services Contract (NOSC) with Exelon to provide management services for plant operations at the Salem and Hope Creek Generating Stations. Prior to implementation of the NOSC on January 17, 2005, PSEG, in cooperation with Exelon, identified a number of personnel changes that would be necessary to implement the Exelon management model at the stations.

While onsite on January 7, 2005, an NRC Region I manager learned that the initial set of personnel actions associated with the NOSC had not been reviewed by the ERB. NRC management requested that PSEG explain why the personnel actions had been taken without being reviewed by the ERB. The NRC also requested that PSEG describe what actions they intended to take in order to accomplish the intended function of the ERB. During follow-up discussions with PSEG management, the NRC learned that several other personnel actions, not associated with implementation of the NOSC, had also occurred without being subjected to the ERB process.

In a letter dated January 31, 2005, PSEG notified the NRC of its intent to commission an independent review of those personnel actions related to the implementation of the NOSC to ensure that they complied with 10 CFR 50.7 "Employee Protection" requirements. While the NRC acknowledged PSEG's intention to perform this review, the NRC, in a letter dated February 17, 2005 requested a written response to specific items detailed in the enclosure to the letter. In a letter dated March 21, 2005, PSEG provided their response.

At the end of the inspection period the inspectors had performed an initial review of PSEG's response and concluded that a more detailed review of the information referenced in the PSEG's response was necessary. This issue is unresolved pending NRC's review of the information referenced in the PSEG response. **(URI 50-272&311/2005002-04, Failure to Implement the ERB Process)**

4. <u>Cross-References to PI&R Findings Documented Elsewhere</u>

Section 4OA5.1 of this report describes a finding in which PSEG did not adequately evaluate the root cause of rotational effects on a turbine driven auxiliary feedwater pump steam admission valve. This issue had a causal factor in problem identification and resolution (PI&R) evaluation.

4OA3 Event Followup (71153 - 2 samples)

1. (Closed) Licensee Event Report (LER) 05000272/2004007-00, Operation in a Condition Prohibited by Technical Specification - Technical Specification 3.3.2.1

This LER described an 11 steam generator steam line flow channel 1 instrument that was left in an inoperable condition after maintenance activities on December 8, 2004. The personnel performance issues and enforcement aspects of this event are described in Section 1R14 of this Inspection Report. No new issues were identified in the LER inspection review. This LER is closed.

2. (Closed) Licensee Event Report 05000272/2004005-00, ECCS Leakage Outside Containment Exceeds Dose Analysis Limits (11 RHR Heat Exchanger)

This LER described mechanical joint leakage from the 11 RHR heat exchanger that was discovered on December 5, 2004, when the 11 RHR loop was placed in service to support shutdown cooling for forced outage activities. The leakage rate exceeded the assumptions made in the dose analysis calculation for emergency core cooling system (ECCS) leakage outside containment. The inspectors reviewed the LER and associated corrective action evaluation in order 70043313. The inspectors determined that this issue represented a minor performance deficiency, because there was no actual radiological consequence due to the RHR heat exchanger leakage. Further, the administrative leakage limits for mechanical joint leakage in the post-accident recirculation path provide defense in depth, by conservatively assuming core damage and to ensure the radiation doses to the control room operators would be within 10 CFR 50 General Design Criterion 19 limits. This LER is closed.

4OA4 Cross Cutting Aspects of Findings

Section 1R14 of this report describes a finding with inadequate procedural adherence that resulted in an inoperable engineered safety feature actuation system instrument. This maintenance technicians' error had a human performance (personnel) cross cutting aspect.

4OA5 Other

1. (Closed) URI 05000272/2004004-02 1MS132 Repeat Malfunctions

Introduction. A Green self-revealing non-cited violation of 10 CFR 50, Appendix B, Criterion XVI, "Corrective Action" was identified when the turbine-driven 13 auxiliary feedwater (AFW) pump steam admission valve (1MS132) malfunctioned on October 16, 2004. The 1MS132 valve malfunction was the fourth since May 24, 2003. Each malfunction rendered the 13 AFW pump unavailable during subsequent corrective maintenance. This item was initially reviewed and documented in Inspection Report

05000272&311/2004004 Section 1R12.2 and remained open pending NRC review of PSEG's root cause evaluation and problem resolution.

Discussion. On October 16, 2004, an equipment operator observed that the position indication arm for 1MS132 was rotated and not properly aligned with the valve stem and position indication assembly. The equipment operator was familiar with past issues related to 1MS132. Those issues occurred on July 14, 2004, May 21, 2004, and May 23, 2003. Control room operators examined the out of alignment valve stem and declared 1MS132 and the 13 turbine drive AFW pump inoperable at 11:40 p.m. on October 16, 2004. The manual steam supply valves to the 13 turbine drive AFW pump were closed at 12:06 a.m. on October 17, 2004, to satisfy compliance with TS 3.6.3.1.c as 1MS132 also provided a containment isolation function.

The Previous 1MS132 Malfunctions were:

C On May 23, 2003, the 13 turbine drive AFW pump tripped during a quarterly surveillance test. PSEG personnel evaluated the condition and observed that 1MS132 valve stem rotated. Corrective actions were focused on improving the tightness of the valve stem to actuator stem coupling block. This issue was dispositioned as a Green NCV in NRC Inspection Report 05000272&311/2003007, Section 1R12.

C On May 21, 2004, operators identified 1MS132 stem block rotated during 13 turbine drive AFW pump surveillance testing. PSEG personnel evaluated the condition and determined that technicians had erroneously assembled a valve stem to actuator stem coupling block by applying lubricant to the threaded stems. This issue was dispositioned as a Green NCV in NRC Inspection Report 05000272&311/2004003, Section 1R19.2.

C On July 14, 2004, at 11:18 p.m., control room operators started the 13 turbine drive AFW pump for surveillance testing. The control room operators noticed on startup that the 1MS132 position indication did not indicate full open. Equipment operators verified locally that 1MS132 was full open. Instrument and controls technicians discovered the linkage rod for the 1MS132 position indication bent during the valve opening. The valve stroked open, but did not indicate so because the position indication linkage rod bound. Control room operators tripped the 13 turbine drive AFW pump at 11:21p.m. 1MS132 was declared inoperable at 11:18 p.m. The manual steam supply valves to the 13 turbine drive AFW pump were closed at 12:24 a.m. on July 15, 2004, to satisfy compliance with TS 3.6.3.1.c. The 13 turbine drive AFW pump was inoperable since 2:48 a.m. on July 14 for associated room cooler maintenance prior to the surveillance test. The inoperability and unavailability of 13 turbine drive AFW pump continued while PSEG personnel investigated and repaired the 1MS132 position indication failure. This issue was identified as an unresolved item in NRC Inspection Report 05000272&311/2004004, Section 1R12.2, pending inspector review of PSEG's evaluation to the 1MS132 malfunction on October 16, 2004.

PSEG's evaluations of the earliest two 1MS132 malfunctions (orders 70031717 and 70039502) concluded that a coupling block between the actuator stem and valve stem was not adequately tightened. The first failure on May 24, 2003, was believed to cause 13 turbine drive AFW pump to trip on startup. PSEG concluded that the loose coupling between the actuator and valve stems caused an erratic stroke on the steam admission valve and the turbine trip throttle valve tripped due to vibrations. The second malfunction on May 21, 2004, did not cause the 13 turbine drive AFW pump to trip, only the 1MS132 position indication was affected. Corrective actions from the first malfunction included specific maintenance instructions to tighten the stem coupling. PSEG believed the second malfunction occurred because maintenance technicians added lubricant to the actuator and valve stems at the stem coupling.

PSEG evaluated the July 14 (third) malfunction and determined that this and the previous two 1MS132 position indication problems were likely related to loose bolting at the limit switch bracket. A loose limit switch housing prevented the linkage rod from traveling unobstructed along the length of valve stem motion and imparted a rotation on the stem coupling block. The evaluation was documented in order 70039502. The evaluation further identified a less than adequate design of the stem coupling. An improved stem coupling design with four bolts, two at each side of the valve and actuator stems, versus the single bolt between the two stems was being pursued by PSEG valve engineers. PSEG expedited the stem coupling four bolt design change and installation and tightened and repaired the limit switch housing and linkage rod. The 13 turbine drive AFW pump and 1MS132 were declared operable after a successful surveillance test and at 1:45 a.m. on July 16, 2004.

The inspectors noted that evaluation 70039502 described a loose actuator stem nut discovered during troubleshooting conducted on July 15, 2004. The actuator stem nut fastens the actuator stem to the air operator valve (AOV) rubber diaphragm. The evaluation did not describe an apparent cause nor resolution of the loose actuator stem nut. The actuator stem nut was tightened to design requirements. The evaluation did note that during troubleshooting the valve stem and actuator stem did not rotate, only the stem block coupling.

PSEG evaluated the October 16 malfunction and determined that 1MS132 was machined in the Fall 2002 refuel outage in an effort to achieve a leak tight shutoff. As a result, a larger than designed diametrical clearance between the plug and seat ring was established and may cause plug rotation during steam admission. PSEG personnel also identified the actuator stem nut at 25 foot-pounds torque versus the 50 foot-pounds required on the actuator stem nut. Unlike the July 14 valve malfunction, PSEG engineers observed that the valve stem, stem coupling block, and actuator stem all rotated together about the AOV diaphragm. PSEG replaced the 1MS132 valve internals consistent with vendor specifications and installed an actuator stem nut with a nylon insert. The 13 AFW pump and 1MS132 were declared operable after a successful surveillance test and at 10:45 and 11:05 p.m. on October 19, 2004.

Analysis. Inadequate problem evaluation resulted in recurrent 1MS132 valve issues and the 13 turbine drive AFW pump being unnecessarily unavailable in July 2004 and

October 2004. The inspectors considered that the two recurrent issues in May 2003 and May 2004 provided ample opportunity for PSEG to properly evaluate the 1MS132 rotational forces and to prevent recurrence. The inspectors appropriately combined the 13 turbine drive AFW pump unavailabilities of July and October 2004 to evaluate the risk significance of the issue. The inspectors considered 13 turbine drive AFW pump unavailable when the manually operated steam supply valves were closed until operators declared 13 turbine drive AFW pump operable after a successful post-maintenance test was completed. The July 2004 issue accrued 25.2 hours of unavailability and the October 2004 issue accrued 71 hours. The combined total was 96.2 hours for the single performance deficiency of ineffective problem evaluation.

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 was associated with the equipment performance attribute, and it affected the Mitigating Systems Cornerstone objective to ensure the availability of systems that respond to undesirable consequences. In accordance with IMC 609, 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 SDP evaluation was required because the finding impacted the mitigating systems cornerstone and represented an actual loss of safety function of a single train for greater than its TS allowed outage time.

The Phase 2 SDP analysis was performed using Revision 1 of the Risk-Informed Inspection Notebook for Salem Generating Station. The inspectors assumed the 96.2 hours of increased unavailability of the 13 turbine drive AFW pump resulted in an exposure time of 3-to-30 days and that no operator recovery credit for the pump was appropriate because the steam supply valves for the 13 turbine drive AFW pump were administratively tagged closed. The inspectors evaluated all of the SDP Phase 2 worksheets except for the small and medium loss-of-coolant accidents and steam generator tube rupture. Using the counting rule, the inspectors determined that the risk significance of the finding based on internal initiating events that lead to core damage was of low to moderate safety significance (white). The inspectors referred the results to the senior reactor analyst (SRA) for further review.

A Phase 3 analysis of the finding performed by the SRA determined that the finding was of very low safety significance (Green). Using Revision 3.11 of the Salem Standard Plant Analysis Risk (SPAR) model, the analyst estimated that the increase in core damage frequency due to internal events was 4E-7. This analysis assumed no credit for operator recovery of the 13 turbine drive AFW pump and that the pump was unavailable for the entire 96.2 hours the pump was administratively considered out-of-service. The dominant core damage sequences involved: a station blackout with failure to recover offsite power or the emergency diesel generators within 4 hours; a loss-of-offsite power with failure of the motor-driven turbine drive AFW pumps and feed and bleed capability; and, a loss of a dc bus with failure of turbine drive AFW and feed and bleed capability.

Because the internal events risk contribution was greater than 1E-7 per year, the analyst continued a Phase 3 evaluation to estimate the increase in risk due to external initiators. The analyst reviewed the Salem Individual Plant Examination of External Events (IPEEE) report for applicable external initiators that could increase the risk significance of the finding. Seismic events, high winds, floods, and “other” external initiators were determined to have no significant contribution to the increase in risk associated with this finding.

With respect to fire and internal flooding, the analyst used a new 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). The tool contained worksheets to analyze the increase in core damage probability due to an unavailable component associated with fire- or flood-induced core damage sequences. Fire ignition frequency, internal flooding frequency, and conditional core damage probability data were based on the licensee’s IPEEE and PRA. The SRA solved 11 fire and internal flooding scenario worksheets that were impacted by the finding. Each worksheet correlated to a set of IPEEE-identified scenarios with similar initiating event characteristics and impact on mitigation capability. The most significant fire scenarios involved: a control room fire causing a transient with loss of the power conversion system (TPCS) and loss of feed and bleed capability; a control room fire that required evacuation or local control of auxiliary feedwater; and, fires that resulted in a TPCS with loss of a 460 VAC bus, 125 VDC Bus, or loss of a 4160 VAC bus. The most significant flooding scenario involved a flood in the relay room resulting in loss of the 28 VDC buses and 115 VAC instrumentation buses, which required local control of the turbine drive AFW system.

Using the worksheets and the assumption that the pump was not recoverable for the entire 96.2 hours exposure window, the analyst estimated that the total risk contribution of this finding due to fire and internal flooding events was 5E-7. The analyst also performed SPAR model runs for several of the scenarios identified in the external notebook which corroborated this result. Therefore, the total increase in core damage frequency due to internal and external initiating events was estimated at approximately 9E-7.

The SRA also performed a screening for potential significance of this finding due to large early release frequency (LERF) in accordance with IMC 0609, Appendix H. The finding was determined to be a Type A finding, as described in Appendix H. Because the Salem facility has a large dry containment and none of the accident sequences associated with the finding involved a steam generator tube rupture or an interfacing system loss-of-coolant accident, the finding screened as green with respect to LERF.

In conclusion, the SRA performed a Phase 3 SDP evaluation for this finding that estimated the increase in core damage frequency due to internal and external initiating events and screened the finding to determine if it were potentially significant from a LERF perspective. The results of the evaluation were that the finding was of very low safety significance (Green).

The performance deficiency associated with the last two 1MS132 failures has a problem identification and resolution cross cutting aspect, specifically evaluation. PSEG did not evaluate the root cause of the valve rotational forces. PSEG also did not evaluate the loose actuator stem nut in July 2004.

Enforcement. 10 CFR 50, Appendix B, Criterion XVI, "Corrective Action," requires that measures shall be established to assure that conditions adverse to quality, such as failures, malfunctions, deficiencies, deviations, defective material and equipment, and nonconformances are promptly identified and corrected. Contrary to the above, on May 24, 2003, and May 21, 2004, rotational effects and malfunctions were identified on 1MS132 and PSEG failed to correct the deficiency. Rotational effects recurred on July 14, 2004, and October 16, 2004, and incurred additional 13 turbine drive AFW pump unavailability. However, because this finding is of very low safety significance and has been entered into PSEG's corrective action program (notification 20207878), this violation is being treated as a non-cited violation, consistent with Section VI.A of the NRC Enforcement Policy. **(NCV 050002722005002-05, 13 Auxiliary Feedwater Pump Steam Admission Valve Repeat Malfunctions)**

4OA6 Meetings, Including Exit

On April 1, 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.

ATTACHMENT: SUPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee personnel
L. Aldrich, Chemistry Superintendent
H. Berrick, Licensing
J. Clancy, Plant Support Manager
J. D'Sousa, Technical Specialist, Plant Support
K. Fleischer, Engineering
M. Fowler, Engineering
C. Fricker, Salem Plant Manager
T. Gierich, Salem Operations Manager
R. Gary, Technical Superintendent - Radiation Protection
A. Hoornik, Chemistry Supervisor
J. Stone, Salem Maintenance Manager
M. Tadjalli, Design Engineering Manager
S. Zeigler, Nuclear Technical Specialist - ALARA

LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

05000272&311/2005002-02	URI	Low Auxiliary Building Ventilation Flows (Section 1R15)
05000272&311/2005002-03	URI	Ground Water Intrusion to the Auxiliary Building and Containment Building Seismic Gap (Section 1R23)
05000272&311/2005002-04	URI	Failure to Implement the ERB Process (Section 4OA2.3)

Opened/Closed

05000272/2005002-01	NCV	Maintenance Practices Render a Protection Instrument Inoperable (Section 1R14)
05000272/2005002-05	NCV	13 Auxiliary Feedwater Pump Steam Admission Valve Repeat Malfunctions (Section 4OA5.3)

Closed

05000272/2004004-00	LER	Operation in a Condition Prohibited by Technical Specification - TS 3.3.2.1 (Section 4OA3.1)
05000272/2004005-00	LER	ECCS Leakage Outside Containment Exceeds Dose Analysis Limits (11 RHR Heat Exchanger) (Section 4OA3.2)
05000272/2004004-02	URI	1MS132 Repeat Malfunctions (Section 4OA5.1)

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 1R02: Evaluation of Changers, Tests, or Experiments

Permanent Plant Modifications

DCP 80073190, SGFP Relay Race with AFW Auto Start Feature
DCP 80019351, Primary to Secondary RMS Leak System Upgrade
DCP 80067588, Salem 22 C/SI Pump Speed Increaser Modification
DCP 80054219, Annunciate Salem 1 SGFP Silent Feed Pump Trips
DCP 80066545, Salem 2 Increase RCS T-avg
DCP 80029403, Appendix "R" Cold Shutdown Contingencies
DCP 80043351, Potential Transformer Drawer Modification in Emergency Diesel Generator Excitation Cabinet
DCP 80067687, Salem Unit 2 Circ Water Switchgear Electrical Reliability Improvement

10 CFR 50.59 Safety Evaluations

S2003-004, Channel 1R15 Condenser Air Ejector Radiation Monitor
S2003-001, Removal of Station Air Compressors from Service
S2003-003, Control Area Ventilation Tracer Gas Test
S2003-005, Salem Unit 1 Digital EHC Upgrade
S2004-003, Salem 2 Digital EHC Upgrade
S2003-006, Salem Unit 1 Turbine Retrofit
S2004-002, Salem Unit 2 Increase RCS T-avg

10 CFR 50.59 Safety Evaluation Screens

DCP Screens

DCP 80073190, SGFP Relay Race with AFW Auto Start Feature

DCP 80019351, Primary to Secondary RMS Leak System Upgrade
DCP 80067588, Salem 22 C/SI Pump Speed Increaser Modification
DCP 80054219, Annunciate Salem 1 SGFP Silent Feed Pump Trips
DCP 80066545, Salem 2 Increase RCS T-avg
DCP 80029403, Appendix “R” Cold Shutdown Contingencies
DCP 80043351, Potential Transformer Drawer Modification in Emergency Diesel Generator
Excitation Cabinet
DCP 80067687, Salem Unit 2 Circ Water Switchgear Electrical Reliability Improvement

Procedure Change Screens

S2.OP-AB.SG-0001, Procedure Change Screening - Steam Generator Tube Leak
S2.OP-SO.SW-0003, 22 Nuclear Service Water Header Outage
S2.OP-SO.CVC-0001, Charging, Letdown, and Seal Injection
S2.OP-ST.ZZ-0003, Inservice Testing Miscellaneous Valves
S2.OP-SO.RHR-0004, Flushing the RHR System to Reduce Radiation Levels

UFSAR Change Screens

SCN 03-005, Peak Temperature in CC Pump Rooms on Loss of Cooler
SCN 03-028, Change to Fire Door in Switchgear and Penetration Area
SCN 03-034, Change to VCT Activities Table
SCN 04-002, Change Testing Discussion for Containment Fan Cooling Units

Temporary Modification Screens

T-Mod 03-018, Install a Temporary Pump in Place of 13 CW Screen Wash Pump
T-Mod 03-006, Reroute Instrument Capillary Tube of 1TD3204

Design References and Calculations

6S1-2140, Seismic II/I Qualification of New EHC Control Cabinet
S-1-RM-SC-4333, Determination of Primary to Secondary Leak
SC-RM018-01, Salem, U2 Steam Generator Primary to Secondary Leak Detection
SC.CH-RC.ZZ-0541(Q), E-Bar Determination
A-37018, Canberra Report for Primary Calibration
WCAP-11525, Probabilistic Evaluation of Reduction in Turbine Valve Test Frequency
WCAP-16054-P, Probabilistic Analysis of Reduction in Turbine Valve Test Frequency
Calc S-C-SW-MDC-1350, Service Water System Mode Ops Analysis
Calc S-C-SW-MDC-1317, Service Water System Hydraulic Model
SCOP-PM.SA-0001, Removal of Station Air Compressors from Service for Maintenance
CALC SC-CN-001-1, Salem Units 1 & 2 Steam Generator Level Trip, Alarm, Indication &
Recording
CN-PCWG-00-10, Salem Units 1 & 2 (PSE/PNJ) PCWG Parameters and Best Estimate Flows
to Support a 1.4% Uprate
S2.IC-CC.RCP-009(Q), 2TE-431A-B #23 Rx Coolant Loop Delta T-Tavg Protection Channel III
S2.IC-FT.RCP-009(Q), 2TE-431A-B #23 Rx Coolant Loop Delta T-Tavg Protection Channel III

S2.OP-AB.CW-001(Q), Circulating Water System Malfunction
S2.IC-FT.RCP-0024(Q), 2PT-505 Turbine Steam Line Inlet Pressure Protection Channel I
S2.IC-CC-RCP-0024(Q), 2PT-505 Turbine Steam Line Inlet Pressure Protection Channel I
S2.IC-CC.RC-0088(Q), 2LC-459 Pressurizer Level Control
SC-RC002-01, Salem Unit 1 & 2 Pressurizer Level
SC-CN001-01, Salem Unit 1 & 2 Steam Generator Level Trip, Alarm, Indication & Recording
S-C-CC-MEE-1440, Loss of Component Cooling 11(21) Pump Room Cooling under LOCA or LOP
SC-RCP-CEE-1037, Evaluation of NUS 7100/Hagan Replacement Module Performance
80039133, Replacement of Dual Comparator (X317645) With Material Master (X374056)
80041963, Replace SR Obsolete Dixson Bargraphs (SH101) with SR Dixson Model SH101P MM1022788
80069787, Steam Generator Programmed Level Setpoint Change
203312, Aux Feed Control Schematic
203327, Aux Feed Control Schematic
247404, Aux Feed Control Schematic

Administrative Procedures

NC.CC-AP.ZZ-0080, Engineering Change Process
NC.NA-AS.ZZ-0059, 10CFR50.59 Program Guidance
NC.CC-AP.ZZ-0003, Modification Walkdown Program for Engineering Changes
NC.WM-AP.ZZ-0002, Corrective Action Process
NC.NA-AP.ZZ-0059, Regulatory Change Determination and 10CFR50.59 Review Process

Notifications and Work Orders

20052643	20176947	70025823	70035009	70043608
20105380	20177118	70029102	70036847	
20128225	20179360	70029524	70036936	
20130791	20190324	70029567	70037259	
20131198	20198289	70030359	70039501	
20136598	20199121	70030561	70040572	
20156380	20203298	70033186	70040781	
20166166	20213936	70034912	70041506	
20166751				

Section 1R04: Equipment Alignment

Procedures

S1.OP-ST.HSD-0001, Instrumentation - Remote Shutdown Panel
S2.OP-ST.HSD-0001, Instrumentation - Remote Shutdown Panel
S1.OP-SO.RHR-0001, Initiating Residual Heat Removal
S1.OP-SO.CC-0001 Component Cooling System Operation
S2.OP-SO.CC-0001 Component Cooling System Operation
S1.OP-SO.AF-0001, Auxiliary Feedwater System Operation

S2.OP-SO.AF-0001, Auxiliary Feedwater System Operation
S1.OP-PT.AF-0001, Service Water to Auxiliary Feedwater Spool Piece Installation
S2.OP-PT.AF-0001, Service Water to Auxiliary Feedwater Spool Piece Installation
SH.OP-AP.ZZ-0103, Attachment 4, "Locked Valve Validation Criteria
SC.DE-PS.ZZ-0049, Control of Inventories of Aluminum and Zinc in the Containments of the Salem Units
S-C-ZZ-NDC-0286, Allowable Aluminum Content in the Salem Containment
S-C-ZZ-SEE-0909, Accountability of Aluminum in Salem Containment

Drawings

205236
205336
AF-1-3A, Sheet 1
AF-2-3, Sheet 2
AF-2-3, Sheet 3
AF-2-3, Sheet 4

Notifications

20159297, 20177734, 20185452, 20185925, 20186185, 20190639, 20191172, 20192622, 20194352, 20202874, 20203525, 20207588, 20207859, 20215621, 20220141,

Work Orders

60040411, 60044562, 60045395, 60045684, 60048255, 60049744, 60051269

Evaluations
70038442, 70038531, 70039691, 70043162, 70043871

Section 1R05: Fire Protection

Pre-Fire Plans
Salem - Unit 1, (Unit 2) Pre-Fire Plan FRS II-441 Relay and Battery Rooms and Corridor
Salem - Unit 1, (Unit 2) Pre-Fire Plan FRS II-511 Electrical Penetration Area
Salem - Unit 1, (Unit 2) Pre-Fire Plan FRS II-431 460 V Switchgear Rooms and Corridor
Salem - Unit 1, (Unit 2) Pre-Fire Plan FRS II-421 4160 V Switchgear Rooms and Battery Rooms

Notifications:

20224543, 20224544, 20224812, 20225752, & 20227905

Section 1R11: Licensed Operator Requalification Program

Procedures

S2.OP-AB.RC-0001, Reactor Coolant System Leak
S2.OP-AB.CW-0001, Circulating Water System Malfunction
2-EOP-TRIP-1, Reactor Trip or Safety Malfunction
2-EOP-FRHS-1, Response to Loss of Secondary Heat Sink

Section 1R12: Maintenance Implementation

Procedures

NC.NA-AP.ZZ-0016, Monitoring the Effectiveness of Maintenance
SH.ER-DG.ZZ-0002, Maintenance Rule (a)(1) Evaluations and Goal Monitoring

Notifications

20091904, 20091905

Orders

70021535, 70025358, 70029034, 70029556, 70030879, 70031040, 70031041, 70031253, 70031468, 70034667, 70034992, 70036826, 70036830, 70037472, 70038081, 70039503, 70041238, 70041163, 70044471, 70045372, 60012970, 60015287, 60018927, 60018962, 60023005, 60024694, 60041369, 60051689

Other Documents

Unit 1 Component Cooling System Health Report (4th Quarter 2004)
Unit 2 Component Cooling System Health Report (4th Quarter 2004)
Unit 1 230/460VAC System Health Report (4th Quarter 2004)
Unit 2 230/460VAC System Health Report (4th Quarter 2004)
Maintenance Rule Expert Panel Meeting Minutes dated November 14, 2002 (SAEP 2002-15)
Maintenance Rule Expert Panel Meeting Minutes dated March 23, 2004 (SAEP 2004-06)
Maintenance Rule Expert Panel Meeting Minutes dated June 28, 2004 (SAEP 2004-09)
Operability Determination 02-005, Potential 460VAC K-Line Breaker Defects per 10 CFR 21
NRC Regulatory Guide 1.160, Monitoring the Effectiveness of Maintenance at Nuclear Power Plants
NUMARC 93-01, Industry Guideline For Monitoring the Effectiveness of Maintenance at Nuclear Power Plants
Salem Unit 2 4KV/230 Volt S2230-2XFR2B4DBY Transformer Failure
Salem 2003 10CFR50.65(a)(32) Periodic Assessment (Report # 80057735)

Orders

60012970, 60015287, 60018927, 60018962, 60023005, 60024694, 60041369, 60051689, 60053063, 60051872, 60043614, 60036408, 60037496, 60051036,

Section 1R13: Maintenance Risk Assessments and Emergent Work Control

Notifications

20197838, 20226093, 20228361, 20196450, 2020252, 20202521, 20204347, 20216858, 20226093, 20224260, & 2022619

Section 1R14: Operator Performance During Non-routine Evolutions and Events

Notifications

20200526, 20208202, 20225397, 20200632, 20204054, 20203734, 20215440, 20203508, 20212395, & 20216755

Section 1R17: Permanent Plant Modifications

For documents reviewed refer to listing under Section 1R02 Documents Reviewed.

Section 1R19: Post-Maintenance Testing

Procedures

S2.OP-PT.CA-0001, Emergency Control Air Compressor Functional Test
S1.OP-ST.SW-0010, Inservice Testing Containment Fan Cooler Unit Service Water Valves
S2.OP-ST.SW-0010, Inservice Testing Containment Fan Cooler Unit Service Water Valves
S1.OP-ST.SW-0002, Inservice Testing - 12 Service Water Pump
S2.OP-ST.CC-0004, Inservice Testing Component Cooling Water Valves
SC.MD-CM.SW-0008, Service Water Pump Headshaft Sleeve Replacement
SH.MD-GP.ZZ-0008, Installation and Removal of Motors

Notifications

20225726, 20225895, 20225900, 20225457, 20225496, 20225621, 20225402, 20228881, 2022882, 20195660, 20196155, 20196683, 20198691, 20198599, 20199210, 20199843, 20205103, 20207272, 20208162, 20211008, 20211977, 20215016, 20217060

Orders

30018179, 30043711, 30070577, 30090398, 30090414, 30106195, 30109835, 30109836, 80078808, 60052430, 70044953, 80078858, & 60052413

Section 1R23: Temporary Plant Modifications

Notifications

20187497, 20193859, 20223887, & 20224590

Chemistry sample results

March 7, 2005 78' elevation mechanical penetration area containment seal leak sample results
March 8, 2005 78' elevation mechanical penetration area containment seal leak sample results
February 26, 2005 WD74 seismic gap drain sample results

Sections 2OS1, 2 & 3: Access Control to Radiologically Significant Areas, ALARA Planning and Controls, and Radiation Monitoring Instrumentation

Updated Final Safety Analysis Report, Sections 12.3 (Radiation Protection Program) and 12.4 (ALARA Program)
Plant Technical Specification 6.12, High Radiation Area
NC.RS-TI.ZZ-0592, Radiation Protection Instrumentation (RPI) Laboratory Calibration and Quality Control
NC.RP-TI.ZZ-0203, High Radiation Area Key Control
NC.RP-TI.ZZ-0204, Posting of Radiological Signs and Barriers
NC.RP-TI.ZZ-0602, Radiation and Contamination Surveys

Section 2PS1: Radioactive Gaseous and Liquid Effluent Treatment and Monitoring Systems

Procedures

S1.OP-ST.RM-0001, Radiation Monitors - Check Sources
S2.OP-ST.RM-0001, Radiation Monitors - Check Sources

Calibration/testing records for the following systems/components

Radiation Monitoring Systems

Low range plant vent noble gas process radiation monitors (1R41A, 2R41A)
Plant vent intermediate range noble gas process radiation monitors (1R41B, 2R41B)
Plant vent high range noble gas process radiation monitors (1R41C, 2R41C)
Composite plant vent noble gas process radiation monitors (1R41D, 2R41D)
Plant vent noble gas background radiation monitors (1R45A, 2R45A)
Plant vent noble gas intermediate range process radiation monitors (1R45B, 2R45B)
Plant vent noble gas high range process radiation monitors (1R45C, 2R45C)
Plant vent particulate process radiation monitors (1R45D, 2R45D)
Steam generator blowdown process radiation monitors (1R19A-D; 2R19A-D)
Liquid waste disposal process radiation monitors (1R18, 2R18)

Fan coil unit process radiation monitors (1R13A-E, 2R13A-C)
Containment atmosphere noble gas process radiation monitors (1R12A, 2R12A)
Containment atmosphere radioiodine radiation monitor (2R12B)
Containment atmosphere particulate process radiation monitors (1R11A, 2R11A)

Flow Rate Measuring Devices
Waste liquid system flow rate monitors
Steam generator blowdown flow rate monitors
Plant vent noble gas sample and process flow rate monitors

Air Treatment Systems

Control room emergency filtration systems
Auxiliary building exhaust air filtration systems
Fuel handling area ventilation systems

Other Documents

Quarterly laboratory cross check results, 2003 & 2004
Salem quarterly and annual dose calculations for effluent releases, 2004
2003 Annual Radioactive Effluent Release Report for the Salem and Hope Creek Generating Station, May 2004
Offsite Dose Calculation Manual for PSEG Nuclear LLC Salem Generating Station, Rev 17
Quality Assurance Assessment Reports: 2004-0069 (ODCM and Procedures); 2003-0175 (Effluent Controls); 2003-0012 (ODCM Instrumentation)
Special Report 311/04-010, 12/13/04, Noble Gas Effluent Monitor (2R45)
Special Report 311/03-002, 11/24/03, Condenser Off-gas Monitor (2R15)
Special Report 272/03-004, 12/5/03, Condenser Off-gas Monitor (1R15)

LIST OF ACRONYMS

AFW	Auxiliary Feedwater Systems
ALARA	As Low As Is Reasonably Achievable
AOV	Air Operator Valve
CFR	Code of Federal Regulations
ECCS	Emergency Core Cooling System
ERB	Executive Review Board
FSAR	Final Safety Analysis Report
I&C	Instrument and Calibration
LER	Licensee Event Report
NCV	Non-cited Violation
NOSC	Nuclear Operations Service Contract
NRC	Nuclear Regulatory Commission
ODCM	Offsite Dose Calculation Manual
ODs	Operability Determinations
OWA	Operator Workaround

PARS	Publicly Available Records
PI	Performance Indicator
PI&R	Problem Identification and Resolution
PMT	Post Maintenance Testing
PSEG	Public Service Electric and Gas
RCS	Reactor Coolant System
RETS	Radiological Effluent Technical Specification
RHR	Residual Heat Removal
SCWE	Safety Conscious Work Environment
SDP	Significance Determination Process
SRA	Senior Reactor Analyst
SSC	Structures, Systems and Components
TS	Technical Specification
UFSAR	Updated Final Safety Analysis Report