November 9, 2004

Mr. A. Christopher Bakken, III
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 05000272/2004004 and 05000311/2004004

Dear Mr. Bakken:

On September 30, 2004, 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 September 30, 2004, with Messrs. Mike Brothers and John Carlin and other members of your staff.

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

This report documents three self-revealing findings of very low safety significance (Green). Two 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 three findings as non-cited violations (NCVs) consistent with Section VI.A of the NRC Enforcement Policy. Additionally, a licensee-identified violation which was determined to be of very low safety significance is listed in this report. If you contest 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 05000272/2004004 and 05000311/2004004
w/Attachment: Supplemental Information

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REGION I

Docket Nos:	50-272, 50-311
License Nos:	DPR-70, DPR-75
Report No:	05000272/2004004 and 05000311/2004004
Licensee:	PSEG Nuclear LLC
Facility:	Salem Nuclear Generating Station, Units 1 & 2
Location:	P.O. Box 236 Hancocks Bridge, NJ 08038
Dates:	July 1 - September 30, 2004
Inspectors:	J. Daniel Orr, Senior Resident Inspector George J. Malone, Resident Inspector Joseph G. Schoppy Jr., Senior Reactor Inspector Sammy C. McCarver, Reactor Engineer Joseph T. Furia, Senior Health Physicist Ram S. Bhatia, Reactor Engineer Suresh K. Chaudhary, Reactor Inspector
Approved By:	Eugene W. Cobey, Chief Projects Branch 3 Division of Reactor Projects

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SUMMARY OF FINDINGS

IR 05000272/2004004, 05000311/2004004; 07/01/2004 - 09/30/2004; Public Service Electric Gas Nuclear LLC, Salem Units 1 and 2; Maintenance Effectiveness, Event Followup, and Other Activities.

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

A. NRC-Identified and Self-Revealing Findings

Cornerstone: Initiating Events

- Green. A self-revealing finding was made apparent when Salem Unit 2 was manually tripped on July 15, 2004, by control room operators for a 23 steam generator feedwater regulating valve malfunction. The reactor trip was preceded by a low steam generator water level automatic reactor trip on July 13, 2004, for the same equipment malfunction. Corrective actions prior to the July 15, 2004, trip were not adequate to prevent recurrence of this problem. The finding was not a violation of NRC requirements, in that the performance deficiencies occurred on non-safety related systems.

  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. The finding is greater than minor because it affected the equipment reliability attribute and had an impact on the objective of the Initiating Events and Mitigating Systems Cornerstones. In accordance with Inspection Manual 0609, Appendix A, "Significance Determination of Reactor Inspection Findings for At-Power Situations," the inspectors conducted a Phase 2 SDP evaluation of the significance of the performance deficiency and determined the finding was of very low safety significance. (Section 4OA3.2)

Cornerstone: Mitigating Systems

- Green. A self-revealing non-cited violation of 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Action," was made apparent when the 1A1 125Vdc battery charger malfunctioned to a reduced charging capacity. The 1C1 and 2C1 battery chargers failed about three months prior, but corrective actions were not implemented to eliminate the identified defective condition for all battery chargers of identical design and like vintage.

Traditional enforcement does not apply because the issue did not have any actual safety consequences or potential for impacting the NRC's regulatory function and was not the result of any willful violation of NRC requirements. This finding was more than minor because it was associated with the equipment performance attribute, and it affected the mitigating systems cornerstone objective to ensure the capability of systems that respond to initiating events. The inspectors determined that the finding was of very low safety significance using the Phase 1 SDP because the finding was not a design or qualification deficiency; it did not represent an actual loss of safety function of a single train for greater than the technical specification allowed outage time; and it did not screen as potentially risk significant for externally initiated core damage accident sequences. (Section 1R12.1)

- Green. A self-revealing finding was identified regarding inadequate procedure guidance and deficient maintenance practices when the Unit 1 turbine building service water isolation valve failed to close on June 2, 2004. The 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. The finding was more than minor, because it was associated with the equipment performance attribute, and it affected the Initiating Events, Mitigating Systems, and Barrier Integrity Cornerstone objectives. The finding was determined to be of very low safety significance based upon a SDP Phase 3 analysis. (Section 4OA5.3)

B. Licensee-Identified Violations

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

REPORT DETAILS

Summary of Plant Status

Unit 1 began the period at 85 percent (%) power. Power was less than 100% to support a 500kV line outage. Unit 1 returned to full power the same day on July 1, 2004. Unit 1 remained at or near 100% power until September 16, 2004, when a 500kV line outage necessitated operators downpower the unit to about 47% power. Salem Unit 1 was returned to 100% power on September 17, 2004. On September 24, 2004, operators performed a plant shutdown to hot standby conditions to facilitate planned maintenance. Unit 1 was restarted on September 28, 2004. The unit was returned to full power on September 29, 2004.

Unit 2 began the period at 100% power. An automatic reactor trip on low steam generator water level occurred on July 13, 2004, due to a feedwater regulating valve malfunction. Unit 2 was restarted on July 15, 2004, but reactor operators inserted a manual reactor trip at about 4% power when a feedwater regulating valve malfunction again occurred causing a low steam generator water level condition. Unit 2 was restarted on July 20, 2004. The unit was returned to full power on July 21, 2004; however, an electrohydraulic control oil system leak the same day necessitated operators reduce power to 19% and secure main turbine operations. On July 23, 2004, the main turbine was back online, and the unit was returned to full power. On September 9, 2004, an automatic reactor trip occurred when the main turbine tripped from a main generator protection signal. On September 13, 2004, Unit 2 was restarted and 100% power was achieved on September 14, 2004. Unit 2 remained at or near 100% power until September 16, 2004, when a 500kV line outage required operators to downpower the unit to about 47% power. Salem Unit 2 returned to 100% power on September 17, 2004. On September 17, 2004, operators reduced power to about 3% and secured main turbine operations to test a main feedwater isolation valve after emergent repairs. Power was restored to 100% on September 19, 2004.

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems and Barrier Integrity

1R01 Adverse Weather Protection (71111.01)

a. Inspection Scope (1 sample)

The inspector performed one adverse weather protection inspection and reviewed PSEG's preparation for seasonal hot weather. The inspector walked down the Salem Unit 1 and Unit 2 service water and component cooling water systems, including verification of compensatory measures directed by operations procedure SC.OP-AB.ZZ-0001, "Adverse Environmental Conditions," for river water temperatures above 82EF. The SH.OP-DG.ZZ-0011, "Station Seasonal Readiness Guide," and SC.OP-PT.ZZ-0002, "Station Preparations for Seasonal Conditions," were also reviewed.

b. Findings

No findings of significance were identified.

1R04 Equipment Alignment (71111.04)

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

During the week of August 2, 2004, the inspectors performed one complete alignment check on the Unit 1 and Unit 2 emergency diesel generator (EDG) fuel oil storage and transfer systems to verify that the systems were properly configured and to identify any discrepancies that might impact the function of these systems. The alignment check included a review of documents to determine the correct system lineup and a field walkdown to identify any discrepancies between the existing lineup and the prescribed lineup. The inspectors also directly observed system performance during the 2C EDG surveillance on August 05, 2004. Additionally, the inspectors interviewed system engineers and reviewed system health reports, completed surveillances, industry operating experience, and corrective action evaluations associated with the EDG fuel oil systems. The documents reviewed are listed in the Supplemental Information attachment to this report.

The inspectors performed partial equipment alignment verifications on redundant equipment during a planned outage on the 13 auxiliary feedwater (AFW) pump on July 15, 2004, an unplanned outage of the 22 AFW pump on July 15, 2004, and a planned outage on the 21 diesel fuel oil storage tank transfer pump on August 16, 2004. The inspectors verified by plant walkdowns and main control room tours that the associated maintenance activities did not adversely affect redundant components. The inspectors also verified that the out of service components were restored to an operable condition following maintenance. Additionally, the inspectors reviewed several corrective action notifications associated with equipment alignment deficiencies (20196474, 20196690, 20196790, and 20196943). Documents reviewed to verify proper alignment 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 (ROP) baseline inspections. In accordance with this deviation, the inspectors reviewed notifications 20148882 and 20203734. PSEG initiated these notifications on separate occasions to address several operator performance issues and mispositioning events. The inspectors verified that PSEG had made adequate progress on the intended corrective actions.

b. Findings

No findings of significance were identified.

1R05 Fire Protection (71111.05)

a. Inspection Scope (3 samples)

The inspectors walked down the Unit 1 and Unit 2 auxiliary building outer penetration rooms and the main control room areas to observe the operational condition of fire detection, suppression and barrier systems, and to verify the proper control of transient combustibles. The inspectors referenced Salem pre-fire plans and NC.DE-PS.ZZ-0001-A6-GEN, "Programmatic Standard Salem Fire Protection Report - General."

b. Findings

No findings of significance were identified.

1R06 Flood Protection Measures (71111.06)

a. Inspection Scope (1 sample)

The inspectors evaluated flood protection measures for Salem Units 1 and 2. All watertight flood protection doors, numerous auxiliary building penetration seals credited for wave runup protection and the auxiliary building and service water intake structure roofs were walked down to verify operational readiness. Operational readiness of auxiliary building sump pumps was assessed. The inspectors also reviewed the results of annual shoreline and berm inspections last performed on December 9, 2003, and an inspection after the remnants of Hurricane Isabel performed on September 17, 2003. The external flood protection engineer was interviewed. Documents reviewed to verify proper alignment are listed in the Supplemental Information attachment to this report.

b. Findings

No findings of significance were identified.

1R07 Heat Sink Performance (71111.07)

a. Inspection Scope (1 biennial sample)

The inspectors reviewed PSEG's programs and processes for assuring that safety-related heat exchangers were operationally maintained and capable of performing their design functions. The inspectors specifically selected a component cooling water (CCW) heat exchanger (HX) (a plate-type HX was selected on Unit 1 and a shell and tube type HX was selected on Unit 2) and an emergency diesel generator (EDG) lube oil and jacket water cooler from each Salem unit.

The portions of the service water (SW) system that affected the cooling system of the CCW and EDGs was also reviewed. This review included the capacity and operational readiness of SW pumps, the system valve line up, and tests and surveillances performed to assure operability.

The inspectors reviewed PSEG's methods for inspection and cleaning of the heat exchangers, flow balance testing of the CCW system, and water chemistry control to assure heat removal capabilities of the selected components were maintained. The current performance characteristics and test results were compared to the design requirements and PSEG's response to Generic Letter 89-13, “Service Water System Problems Affecting Safety-Related Equipment.” The heat exchanger inspection, cleaning, and maintenance methods and frequencies were reviewed with the system engineers and assessed to determine results and practices were consistent with expected degradation trends and industry practice. The heat exchanger design calculations, and performance evaluations were reviewed with system engineers and compared to heat exchanger design capabilities. PSEG's chemical treatment program was also reviewed to verify that potential bio-fouling mechanisms had been identified, treatments were conducted as scheduled, and results were monitored for effectiveness.

The inspectors reviewed heat exchanger inspection and cleaning records to verify that the results were properly evaluated to ensure adequate heat transfer capabilities. The inspectors reviewed heat exchanger design basis values and assumptions, plugging limit calculations, and vendor information, to verify that they were incorporated into the heat exchanger inspection and maintenance procedures.

In addition, the inspectors reviewed system health reports regarding the selected heat exchangers, and several notifications to assure that problems affecting the heat exchangers were appropriately identified and resolved. Finally, the inspectors conducted a walkdown of the service water intake structure and portions of the service water system, including the selected heat exchangers, to assess material condition.

b. Findings

No findings of significance were identified.

1R11 Licensed Operator Requalification (71111.11)

a. Inspection Scope (2 samples)

On August 26 and 31, 2004, the inspectors observed licensed operator simulator training sessions to assess operator performance and the evaluators’ post-scenario critiques. The August 26, 2004, training scenario involved several balance of plant instrument failures necessitating a steam generator feedwater pump manual trip, a pressurizer power-operated relief valve partially stuck open, and a steam generator tube rupture. The August 31, 2004, training scenario involved an automatic reactor trip with two control rods stuck out of the core followed by a loss of all AC power which was further complicated by the loss of the 23 auxiliary feedwater pump. The inspectors verified operator actions were consistent with Salem operating, alarm response, abnormal, and emergency procedures. The inspectors also verified that evaluators identified deficient operator performance where appropriate. Training scenarios S-RSG-058 and LOR-033 detailed the scenario events and the expected operator response for each event. Several procedure references were listed within the training scenario references and were reviewed by the inspectors.

b. Findings

No findings of significance were identified.

1R12 Maintenance Implementation (71111.12)

a. Inspection Scope (2 samples)

Routine Maintenance Effectiveness Inspection. The inspectors performed two maintenance effectiveness inspections and reviewed notifications documenting past operating problems, system health reports, and maintenance rule performance criteria to determine if PSEG had effectively monitored the performance of two emergent issues. The issues involved a turbine driven auxiliary feedwater pump steam admission valve (1MS132) and a 125Vdc safety-related battery charger failure (1A1 battery charger). The inspectors interviewed system engineers and valve engineers to determine the effectiveness of established and proposed corrective actions. The inspectors also 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.

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 (ROP) baseline inspections. In accordance with this deviation, the inspectors reviewed condition reports associated with deficiencies in the Salem Unit 2 service water system to assess the corrective action process quality and to verify completion of prescribed corrective actions. The condition reports (70029662, 70031456, 70031155, and 70034763) involved service water valve replacement part availability, service water valve reliability, and service water strainer maintenance.

b. Findings

1. Vital 125Vdc Battery Charger Failures

Introduction. A Green self-revealing NCV of 10 CFR 50, Appendix B, Criterion XVI, “Corrective Action,” was identified when the 1A1 125Vdc battery charger failed during routine operation. Two other battery chargers, identical in design and of like vintage, had similarly failed about four months prior.

Discussion. On March 17, 2004, the 2C1 battery charger failed surveillance test SC.MD-ST.125-0001, “Preventive Maintenance and 18 Month Surveillance of 125 Volt Battery Chargers,” that measured charger capacity. The 2C1 battery charger only delivered 150 amperes (amps) versus Technical Specification surveillance requirement 4.8.2.3.2.e, that vital D.C. battery chargers supply at least 170 amps at 125 volts for at least four hours. The battery charger was designed to deliver 180 amps. The 2C1 battery charger had already been considered inoperable for maintenance and testing. Maintenance technicians identified a blown fuse and a charred voltage transducer.

The voltage transducer had been installed special order during initial procurement in the early 1990's by C&D Industrial Batteries and Chargers. The voltage transducer was always energized but its output was never used for any function. PSEG technicians and engineers identified a small transformer supplying an electronic card for the transducer that appeared to be the source of overheating and failure. The transducer failure caused a one amp fuse, AXF2-1, to blow. The battery charger was observed operating at reduced capacity because fuse AXF2-1 also primarily supplied a portion of the battery charger firing circuits. Specifically, the blown fuse deenergized one of six firing circuits within the charger reducing the capacity from 180 amps to 150 amps.

Salem Units 1 and 2 each have a primary battery charger associated with all three vital D.C. busses. Backup battery chargers are also permanently installed, but per Technical Specification 3.8.2.3.b are limited to operate on only one of the three busses for no more than seven days of plant operation. The backup battery chargers are backed by A.C. power that is out-of-channel (e.g., the 2C battery backup charger, 2C2, is powered from B vital A.C. power).

PSEG technicians performed an extent of condition review for all primary and backup battery chargers on both Salem Units, eleven chargers in addition to the 2C1 battery charger. On March 24, 2004, during the extent of condition review, electricians identified a blown fuse and a charred transducer for the 1C1 battery charger. The 1C1 had failed similarly to the 2C1 battery charger. The 1C1 battery charger was returned to service on March 26, 2004, after a new voltage transducer was installed.

On June 14, 2004, PSEG engineers received Plant Health Prioritization Committee approval to initiate a design change package for removal of the unused transducers on all battery chargers. System engineers performed visual walkdowns of each battery charger several times each week. However, the walkdowns were not documented nor required by any administrative process or performed on any predetermined periodicity.

On July 29, 2004, at 11:34 p.m., control room operators received a control room alarm associated with the 1A1 battery charger. Operators and technicians were dispatched to investigate and noticed a burnt smell. Operators deenergized the 1A1 battery charger and placed the backup charger, 1A2, in service. Maintenance technicians and engineers determined the 1A1 battery charger had failed for identical reasons. The 1A1 battery charger was repaired with a new transducer and returned to service on July 31, 2004, at 01:58 a.m. A new transducer was reinstalled unused as before because the design change package to remove the unused transducers was not yet developed for implementation.

Analysis. The performance deficiency associated with the 1A1 battery charger failure has problem identification and resolution cross cutting aspects. Specifically, PSEG was slow to implement a long term resolution for transducer failures and the 1A1 battery charger was rendered inoperable. PSEG also did not initiate interim corrective actions that were successful in identifying transducer failures before the battery chargers were adversely impacted with reduced charging capacity.

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 reliability of systems to respond to initiating events. The inspectors considered the loss of D.C. bus initiating event for the Initiating Events cornerstone and determined that the failure mechanism, reduced charging capacity, did not increase the likelihood of a loss of D.C. bus. The inspectors determined that the finding was of very low safety significance (Green) using the Phase 1 SDP because the finding was not a design or qualification deficiency that resulted in a loss of safety function; it did not represent an actual loss of safety function of a single train for greater than the TS allowed outage time; and it did not screen as potential risk significant for externally initiated core damage accident sequences.

Enforcement. 10 CFR 50 Appendix B, Criterion XVI, "Corrective Action," requires that in the case of significant conditions adverse to quality, measures shall assure that the cause of the condition is determined and corrective actions taken to preclude repetition. Contrary to the above, on July 29, 2004, PSEG did not preclude repetition of failed safety-related battery chargers due to defective transducers, a significant condition adverse to quality, when the 1A1 battery charger failed. The 2C1 and 1C1 battery chargers had failed for identical reasons on March 18 and March 24, 2004, respectively. However, because the finding is of very low safety significance and has been entered into the corrective action program in notification 20207005, this violation is being treated as an NCV, consistent with section VI.A of the NRC Enforcement Policy: **NCV 05000272/2004004-01, Untimely Problem Resolution for 125VD.C. Battery Charger Failures.**

2. 13 Auxiliary Feedwater Pump Steam Admission Valve Repeat Malfunctions

The issue involving 13 auxiliary feedwater (AFW) pump steam admission valve (1MS132) repeat malfunctions is unresolved pending inspector review of PSEG's evaluation of an October 16, 2004, malfunction. 1MS132 position indication malfunctioned on May 24, 2003, May 21, 2004, July 14, 2004, and October 16, 2004. Each malfunction has had similar symptoms, in that, the connecting rod from the valve stem to the limit switch rotated radially from its normal position, has bent on occasion, and did not operate the open limit switch when the valve was full open. Each subsequent repair accumulated unplanned 13 AFW pump unavailability when operators isolated the manual steam isolation valves to facilitate troubleshooting and maintenance and to comply with Technical Specification 3.6.3.1 for an inoperable containment isolation valve. The first two 1MS132 malfunctions were documented in NRC Inspection Reports 05000272, 311/2003007, Section 1R12 and 05000272, 311/2004003, Section 1R19.2. The July 14, 2004, 1MS132 malfunction was evaluated by PSEG engineers in order 70039502. The October 16, 2004, malfunction was documented in PSEG notification 20207415. The inspectors verified that there were no current operability concerns with the 13 AFW pump in regard to 1MS132 performance. This issue is unresolved pending inspector review of PSEG's evaluation to the 1MS132 malfunction on October 16, 2004, and evaluation of PSEG's problem resolution performance for each prior occurrence. The issue is identified as **URI 05000272/2004004-02, 1MS132 Repeat Malfunctions.**

1R13 Maintenance Risk Assessments and Emergent Work Evaluation (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:

- 11 service water header and 12 component cooling water heat exchanger concurrent out-of-service conditions on July 6, 2004;
- 21 safety injection pump, 21 containment fan coil unit, and 21 service water pump concurrent out-of-service conditions with reactor power ascension activities on July 23, 2004;
- Salem Unit 3 gas turbine generator out-of-service on July 26, 2004;
- 12 charging pump out-of-service on August 5, 2004;
- 11 auxiliary feedwater pump and 11 auxiliary building ventilation supply fan concurrent out-of-service conditions with 16 service water pump surveillance testing on August 17, 2004 ; and
- 22 charging pump maintenance window concurrent with 25 service water pump and 23 control area ventilation fan out-of-service conditions on August 31, 2004.

b. Findings

No findings of significance were identified.

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

a. Inspection Scope (4 samples)

The inspectors observed control room operators during the performance of four non-routine plant evolutions. The inspectors reviewed operating procedures, attended operator briefings, observed reactor operators manipulate controls during various steps within the operating procedures, and interviewed senior reactor operators regarding contingency plans. Procedures reviewed are listed in the Supplemental Information attachment to this report.

- On July 20, 2004, inspectors observed control room operators perform a plant start-up. The plant was returning to operation after a reactor trip that occurred on July 15, 2004, due to failure of a main feedwater regulating valve, 23BF19. (This issue is also discussed in section 4OA3.2 of this report.) Inspectors monitored the approach to criticality and observed operation of the main feed regulating valves during power ascension.

- On July 21, 2004, the inspectors reviewed the control room operators' response to a Salem Unit 2 electrohydraulic control system oil leak on the No. 4 main turbine governor valve, 24MS29. Control room operators reduced Salem Unit 2 power from 100% to 35% reactor power and took the main turbine off-line. The inspectors observed main control room operators maintain mode 1 conditions with the steam dump system.

- The inspectors reviewed the control room operators response to a July 21, 2004, Salem Unit 1 Technical Specification prohibited condition identified by a control room operator during a panel walkdown. The technical specification prohibited condition involved a control room ventilation chiller taken out of service for maintenance and non-essential chilled water loads that were mistakenly unisolated during conduct of routine plant operations. The details of this issue are discussed in section 4OA3.6 of this inspection report.

- On September 12, 2004, the inspectors observed control room operators perform a Unit 2 reactor startup. Specifically, the inspectors observed the approach to criticality and power established at about 1.5% while equipment operators prepared the turbine building for further power ascension.

b. Findings

No findings of significance were identified.

1R15 <u>Operability Evaluations</u> (71111.15)

a. <u>Inspection Scope (4 samples)</u>

The inspectors reviewed four operability determinations (ODs). 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:

- Cycling of 12AF40 auxiliary feed pump minimum flow valve on August 17, 2004 (Notification 20159382);
- Auxiliary building ventilation configuration in Unit 2 SI pump room on July 20, 2004 (Notification 20197686); and
- Seat leakage past 22SJ56 and 22SJ144 (Notification 20192178)
  Unit 2 auxiliary building ventilation low flow condition (Order 70039941).

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 (ROP) baseline inspections. In accordance with this deviation, the inspectors reviewed an OD (order 70032821) that was closed on July 31, 2004. The OD was associated with a July 29, 2003, Unit 1 reactor trip due to a fault in the 500kV switchyard. The OD addressed potential unanticipated separation of 4kV vital busses from offsite power sources. The inspectors verified that PSEG had appropriately addressed all issues within the OD and that the OD was appropriately closed.

b. <u>Findings</u>

No findings of significance were identified.

1R19 <u>Post Maintenance Testing</u> (71111.19)

a. <u>Inspection Scope (4 samples)</u>

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

- 11 auxiliary feedwater pump flow control valves calibrations on August 17, 2004;
- 12 control room ventilation chiller preventative maintenance on August 26, 2004;

- Cell #34 replacement on the 1C 125Vdc vital battery on September 2, 2004; and
- 22 steam generator feedwater isolation valve, 22BF22, packing adjustment and leak seal repair on September 18, 2004.

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 documents; (4) test instrumentation had current calibrations, 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.

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 (ROP) baseline inspections. In accordance with this deviation, the inspectors reviewed notification 20191860 that involved an incomplete PMT for safety related breaker cubicles. The inspectors verified that PSEG had appropriately resolved the issues within the corrective action process.

b. <u>Findings</u>

No findings of significance were identified.

1R20 <u>Refueling and Other Outage Activities</u> (71111.20)

a. <u>Inspection Scope (1 sample)</u>

Following the July 13 and July 15, 2004, Unit 2 reactor trips (also discussed in Section 4OA3 of this inspection report) the inspectors evaluated PSEG's shutdown risk management and forced outage configuration control and observed reactor startups and power ascension activities. Associated PSEG notifications are listed in the Supplemental Information attachment to this report and were reviewed by the inspectors. The inspectors also reviewed the following procedures and documents that controlled plant operations:

- Hot Standby to Minimum Load (S2.OP-IO.ZZ-0003), Revision 19;
- Core Operating Limits Report for Salem Unit 2, Cycle 14 (NFS-0231), Revision 1;
- Inverse Count Rate Ratio During Reactor Startup (SC.RE-RA.ZZ-0002), Revision 2;
- Maintaining Hot Standby (S2.OP-IO.ZZ-0008), Revision 9; and
- Shutdown Margin Calculation (SC.RE-ST.ZZ-0002), dated July 15, 2004.

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 surveillance tests:

- 2C EDG monthly surveillance test with preventative maintenance activities to hot torque banjo bolts on August 5, 2004;
- 1A EDG post-maintenance surveillance test on August 16, 2004;
- 11 RHR pump inservice test on August 19, 2004;
- Service water silt survey results for all pump bays and both Salem units from August 1999 to August 2004; and
- Unit 2 Reactor Coolant System Water Inventory Balance on September 28, 2004.

Additionally, the inspectors reviewed a surveillance testing problem associated with 12 charging pump discharge check valve seat leakage discovered on June 13, 2004, after performance of S1.OP-ST.CVC-0005, "Inservice Testing - 13 Charging Pump," on June 6, 2004.

The inspectors verified that the apparent or root cause of equipment failures were adequately explored, corrective actions developed, and the basis for returning equipment to an operable status was acceptable.

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 (ROP) baseline inspections. In accordance with this deviation, the inspectors reviewed notification 20182050. The notification involved a surveillance testing issue that rendered a reactor protection system instrument inoperable. The inspectors verified that PSEG developed and implemented appropriate corrective actions.

b. Findings

No findings of significance were identified. However, issues involving SW silt survey results and the 1CV52 seat leakage are unresolved.

The issue involving SW silt survey results are unresolved pending inspector review of PSEG's past operability determination of abnormally high as-found silt levels. Specifically, the 15 SW pump bay silt level was measured as high as twelve feet on June 15, 2004. The SW pump suctions are four and-a-half feet below Salem's low water design level for the Delaware River as described in the Updated Final Safety Analysis Report, Figure 3.4-1 and Section 9.2. The inspectors considered that a twelve foot silt measurement should be evaluated and considered for past operability review. The inspectors verified that PSEG had performed desilting since the high silt level measurements and that there were no current operability concerns with the service water pumps in regard to silting. This issue was entered into PSEG's corrective action program as notifications 20202848 and 20202849. This issue is unresolved pending inspector review of PSEG's past operability determination of abnormally high as-found silt levels and is identified as **URI 05000272, 311/2004004-03, Service Water Desilting Practices.**

The issue involving 1CV52 is unresolved pending inspector review of PSEG's evaluation of past check valve surveillance practices. 1CV52 is the 12 charging pump discharge check valve. The Salem Unit 1 design incorporates three high pressure charging pumps: two safety-related centrifugal pumps (11 and 12 charging pumps) and one positive displacement pump (13 charging pump). These pumps are in parallel discharging to a common header. During normal plant operation only one charging pump is operated. Each pump has a discharge check valve to prevent back-flow should the pump be idle. Preventing significant back-flow is required to maintain design flow to the charging and safety injection systems. At 2:35 a.m., on June 6, 2004, operators conducted a pump flow test of the 13 charging pump. The 13 charging pump exhibited low flow and failed the test. A troubleshooting effort began at 2:41 a.m. on June 14, 2004, which identified that back leakage existed through the 12 charging pump discharge check valve, 1CV52. Equipment operators isolated the 12 charging pump at 4:46 a.m. on June 14, 2004. This issue was entered into PSEG's corrective action program as notifications 20192278 and 20193182. This issue is unresolved pending inspector review of PSEG's evaluation of past check valve surveillance practices and is identified as **URI 05000272/2004004-04, 1CV52 Back Leakage.**

Cornerstone: Emergency Preparedness [EP]

1EP6 <u>Drill Evaluation</u> (71114.06)

a. <u>Inspection Scope (2 Samples)</u>

The inspectors observed an EP drill from the Salem control room simulator and the emergency operations facility on July 21, 2004, and a licensed operator requalification exam from the Salem control room simulator on August 31, 2004. The inspectors evaluated the conduct of the drill and exam, including performance of initial and escalated classifications, required notifications, and protective action recommendations. The inspector also observed and evaluated the post-drill and exam critiques. The inspector also reviewed the Salem/Hope Creek Emergency Plan and the Salem Event Classification Guide. The inspector referenced Nuclear Energy Institute (NEI) 99-02, "Regulatory Assessment Performance Indicator (PI) Guidelines," and verified that PSEG had correctly counted this drill's contribution to the NRC PI for Drill and Exercise Performance.

b. Findings

No findings of significance were identified.

2. RADIATION SAFETY

Cornerstone: Occupational Radiation Safety [OS]

2OS1 Access Control to Radiologically Significant Areas (71121.01)

a. Inspection Scope (9 samples)

The inspector examined PSEG's physical and programmatic controls for highly activated or contaminated materials (non-fuel) stored within spent fuel and other storage pools.

The inspector reviewed PSEG's self assessments, audits, licensee event reports, and special reports related to the access control program since the last inspection, and determined that identified problems were entered into the corrective action program for resolution.

The inspector selected jobs being performed in radiation areas, airborne radioactivity areas, or high radiation areas (<1 R/hr) for observation and: reviewed all radiological job requirements (RWP requirements and work procedure requirements); observed job performance with respect to these requirements; and, determined if radiological conditions in the work area were adequately communicated to workers through briefings and postings.

The inspector verified the adequacy of radiological controls, such as: required surveys (including system breach radiation, contamination, and airborne surveys), radiation protection job coverage (including audio and visual surveillance for remote job coverage), and contamination controls.

For high radiation work areas with significant dose rate gradients, the inspector reviewed the application of dosimetry to effectively monitor exposure to personnel and verified PSEG controls were adequate.

The inspector discussed with the Radiation Protection Manager (RPM) high dose rate, high radiation area and Very High Radiation Area (VHRA) controls and procedures and verified that any changes to PSEG procedures did not substantially reduce the effectiveness and level of worker protection.

The inspector discussed with first-line health physics (HP) supervisors the controls in place for special areas that have the potential to become VHRA during certain plant operations. The inspector determined that these plant operations require communication beforehand with the HP group, so as to allow corresponding timely actions to properly post and control the radiation hazards.

During job performance observations, the inspector observed radiation worker performance with respect to stated radiation protection work requirements and determined that they were aware of the significant radiological conditions in their workplace, and the RWP controls/limits in place, and that their performance took into consideration the level of radiological hazards present.

During job performance observations, the inspector observed radiation protection technician performance with respect to all radiation protection work requirements. The inspector determined that they were aware of the radiological conditions in their workplace and the RWP controls/limits, and if their performance was consistent with their training and qualifications with respect to the radiological hazards and work activities.

b. Findings

No findings of significance were identified.

2OS2 ALARA Planning and Controls (71121.02)

a. Inspection Scope (2 samples)

The inspector reviewed if there had been any declared pregnant workers during the current assessment period and reviewed the exposure results and monitoring controls employed by the licensee with respect to requirements of 10 CFR 20.

The inspector reviewed PSEG's self-assessments, audits, and special reports related to the ALARA program since the last inspection and determined that PSEG's overall audit program's scope and frequency met the requirements of 10 CFR 20.1101(c).

b. Findings

No findings of significance were identified.

2OS3 Radiation Monitoring Instrumentation (71121.03)

a. Inspection Scope (1 sample)

The inspector reviewed PSEG's self-assessments, audits, and licensee event reports and focused on radiological incidents that involved personnel contamination monitor alarms due to personnel internal exposures. For internal exposures >50 mrem CEDE, the inspector determined that the affected personnel were properly monitored utilizing calibrated equipment and that the data was analyzed and internal exposures properly assessed in accordance with PSEG procedures.

b. Findings

No findings of significance were identified.

4. OTHER ACTIVITIES [OA]

4OA1 Performance Indicator Verification (71151)

a. Inspection Scope (8 samples)

The inspectors reviewed PSEG's program to gather, evaluate and report information on the following four performance indicators (PIs) for both Salem units. The inspectors used the guidance provided in NEI 99-02, Revision 2, "Regulatory Assessment Performance Indicator Guideline," to assess the accuracy of PSEG's collection and reporting of PI data.

Heat Removal System Unavailability and Decay Heat Removal System Unavailability PIs. The inspectors verified the methods used to calculate unavailabilities and reviewed the accuracy of the PI data submitted for July 1, 2003, to June 30, 2004. Control room logs were reviewed for the dates when these systems were scheduled to be out of service by the work management program.

Occupational Exposure Control Effectiveness PI. The inspector reviewed all PSEG PIs for occupational exposure control effectiveness. The inspector also reviewed a listing of licensee event reports for the period January 1, 2004 through August 30, 2004, for issues related to the occupational radiation safety.

RETS/ODCM Radiological Effluent Occurrences PI. The inspector reviewed a listing of licensee event reports for the period January 1, 2003, through September 3, 2003, for issues related to the to radiological effluent occurrences.

4OA2 Problem Identification and Resolution (71152)

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

1. Annual Sample Review

a. Inspection Scope (1 sample)

The inspectors selected seven notifications (20158333, 20158259, 20158261, 20158262, 20158263, 20175469, 20190856) for detailed review. The issues identified in these notifications were associated with the auxiliary feedwater system for Salem Units 1 and 2 and evaluated Salem applicability to NRC information Notice 2004-01, "Auxiliary Feedwater Pump Recirculation Line Orifice Fouling - Potential Common Cause Failure," an over-pressurization of 12 auxiliary feed pump suction piping, and two failures associated with the steam admission valve to the Unit 1 steam driven auxiliary feedwater pump.

b. Findings and Observations

There were no findings identified with the reviewed notifications. The inspectors concluded that adequate root cause analyses were performed and corrective actions were appropriate and executed in a timely manner relative to the identified problems or issue.

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

Section 1R12.1 describes a finding for failure to correct a defective safety-related battery charger condition. PSEG repaired identical conditions on two other occasions for two other individual battery chargers. The first was identified through surveillance testing and the second through an extent of condition review. Four months later a third failure occurred on another individual battery charger because corrective actions were not implemented to eliminate the identified defective condition for all battery chargers of identical design and like vintage.

Section 4OA3.2 describes a Unit 2 reactor trip that occurred on July 15, 2004. The manual reactor trip occurred because PSEG had not identified an equipment malfunction within the main feed regulating valve positioners that also caused a July 13, 2004, automatic reactor trip.

4OA3 Event Followup (71153 - 6 samples)

1. (Closed) LER 05000311/2004006-00, Salem Unit 2 Automatic Reactor Trip on July 13, 2004

On July 13, 2004, Salem Unit 2 experienced an automatic reactor trip. The reactor trip occurred due to a low steam generator water level condition in the 21 steam generator while performing a surveillance test on a main feed pump discharge pressure transmitter. The low water level was caused by the failure of the 21 steam generator main feed water regulating valve, 21BF19, to maintain proper position. The inspectors reviewed the LER with no findings identified. The inspectors also verified that timely notifications were made in accordance with 10 CFR 50.72, PSEG staff implemented the appropriate procedures, and plant equipment performed as designed. PSEG documented the event and the subsequent evaluation in notification 20196681. A subsequent manual reactor trip occurred on July 15, 2004, for the same causes and is described in the following section of this report and in LER 05000311/2004007-00. This LER is closed. This event did not constitute a violation of NRC requirements.

2. (Closed) LER 05000311/2004007-00, Salem Unit 2 Manual Reactor Trip on July 15, 2004

a. Inspection Scope

On July 15, 2004, the inspectors responded to the site and evaluated operator response to a manual reactor trip. The inspectors reviewed operator logs, applicable abnormal operating procedures, post-trip review report, and the overhead alarm chronology to assess control room operators' response and equipment performance. The inspectors independently performed control room panel and in-plant system walkdowns to verify the status of potentially affected risk significant systems. The inspectors also observed a Station Operating Review Committee post-trip review on July 16, 2004.

The inspectors later reviewed the associated LER and corrective action evaluation (notification 20196676) to verify that the cause of the reactor trip was identified and that the corrective actions were appropriate.

b. Findings.

Introduction. A Green self-revealing finding was identified for failure to prevent recurrence of a Unit 2 reactor trip that occurred because of the same equipment deficiencies on July 13 and July 15, 2004. Because the equipment involved was not safety related there was no violation of regulatory requirements, however, the Initiating Events and Mitigating Systems Cornerstone Objectives were impacted.

Description. On July 13, 2004, instrument and controls maintenance technicians performed a calibration activity on a main feed pump discharge pressure transmitter. During the activity, 21 steam generator (SG) feedwater regulating valve (21BF19) position decreased from the expected position of approximately 60% open to 30% open. 21 SG water level lowered in response to the restricted feedwater flow. Operators attempted to take manual control of 21BF19, but the valve did not respond. 21 SG water level reached 14% level causing an automatic reactor trip.

Subsequent troubleshooting efforts later identified the 21BF19 valve positioner operated incorrectly. The function of the valve positioner was to receive an electronic signal from a plant computer and convert that signal into a pneumatic force to operate the valve. The valve positioner had sub-components, namely the current-to-pneumatic (I/P) converter and the shuttle block assembly which were identified as being possible causes of the positioner malfunction. The I/P converter changed the electric current into a corresponding air pressure. The shuttle block assembly consisted of a rod with six piston heads within a block with several ports. The shuttle block developed the correct air pressure to act on the valve diaphragm. Troubleshooting tests of the positioner at the manufacturer's facility did not reproduce the problem. However, inspection of the sub-components found that the shuttle rod had a surface defect on it which appeared to be a result of hard contact between the piston-head and the shuttle block. This hard contact could have restricted valve movement by not allowing the positioner output to respond to a change in demand.

PSEG subsequently learned that manufacturing quality assurance practices specific to the involved valve positioner were improved in year 2002. PSEG concluded that replacement of the 21BF19 valve positioner with one manufactured after 2002 was an appropriate corrective measure to address the shuttle rod defect.

During extent of condition testing, maintenance technicians identified that 23BF19 valve also exhibited similar deficient operation. The 23BF19 valve failed to stroke after several attempts at resetting its control signal. The failure mechanism appeared to be indicative of a stuck shuttle valve. The positioner for the 23BF19 valve was replaced with a model built after 2002.

On July 15, 2004, the Station Operating Review Committee concluded that adequate actions were completed to address the Unit 2 feedwater regulating valve issue (21BF19 and 23BF19). Control room operators commenced a plant startup on July 15, 2004. At approximately 8% reactor power, transition from bypass feedwater flow to main feedwater flow occurred. However, the main feedwater regulating valve for the 23 steam generator, 23BF19, failed to open. Water level in the 23 steam generator lowered due to the insufficient feed flow. Operators attempted to take manual control of the 23BF19, but the valve did not respond. Operators manually tripped the reactor when 23 SG water level approached 16% level.

Investigation following the July 15 trip again identified problems with the 23BF19 valve positioner. The shuttle was visually observed to be stuck. The shuttle was depressed and the valve opened.

The 23BF19 positioner was tested at the manufacturer’s facility. Again testing revealed no problems, but inspection identified longitudinal scratches which indicated galling on the shuttle. Because of the tight clearances of the pilot valve, the scratches could have prevented operation of the positioner.

PSEG identified shuttle overshoot as a contributing cause of positioner failure. Overshoot occurred when the inner surface of the outer piston head extended beyond the edge of the shuttle block past its design distance. The extra travel distance was due to a combination of back-pressure force provided by the BF19 actuator and a previous design change of the C-spring which holds the shuttle rod in the block. The design change reduced the strength of the spring. The C-spring applied a bending force to the shuttle rod such that when it overextended, the piston head struck the block upon reentry.

PSEG also identified poor air quality as a potential cause of positioner problems. The pressure regulator upstream of the positioner had a capability of filtering particles larger than 40 microns and there was a screen prior to the I/P that removed fines. The positioner was designed to be only tolerant of particulate less than 5 microns. PSEG found large amounts of particulate in the I/P screen on one of the removed positioners from Unit 2. Some moisture was also detected in the control air.

PSEG found the manufacturer had implemented manufacturing process improvements after January 28, 2004, that affected the quality of the shuttle assembly and may improve the quality of the surface finish of the components as well as improve fitting of the shuttle rod within the shuttle block.

PSEG added air volume boosters to the valve positioners to eliminate the problem of overshoot. All BF19 positioners (four in each unit) for both Unit 1 and Unit 2 were also replaced with valve positioner models manufactured after January 28, 2004, to take advantage of manufacturing improvements that improved reliability of the shuttle valve component. The Unit 2 maintenance occurred prior to July 20, 2004, and prior to any additional plant startups. The Unit 1 maintenance occurred during a planned outage on September 25, 2004.

Analysis. The performance deficiency associated with this finding has a problem identification and resolution cross cutting aspect. Equipment malfunctions that resulted in a reactor trip should be corrected consistent with PSEG procedure SH.OP-AP.ZZ-0101, "Post-Trip Response Requirements." Procedure 4.2 described the objective of the procedure to determine corrective actions to prevent recurrence of reactor trip events. Specifically, PSEG failed to correct an equipment malfunction that resulted in an automatic reactor trip on July 13, 2004, prior to restarting the unit. As a result, a manual reactor trip was inserted on July 15, 2004, when a main feedwater regulating valve malfunctioned in the same manner. 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 Initiating Events and Mitigating Systems Cornerstone objective. 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 contributed to both the likelihood of a reactor trip and the likelihood that mitigation equipment, the power conversion system, would not be available.

The inspectors conducted a Phase 2 SDP evaluation and determined the finding to be of very low safety significance (Green) because, although the likelihood of a transient increased, the exposure time for this condition was less than three days and all mitigation capabilities described on the SDP phase 2 worksheet for transient initiated core damage sequences were maintained. Because the finding directly affects the likelihood of a transient, the initiating events likelihood for the transient initiated core damage sequences were raised by one order of magnitude. The dominant accident sequence involved a reactor trip with the requirement of the auxiliary feedwater system, power conversion system, and early high-pressure injection systems to be operational to mitigate the plant transient.

Enforcement. The performance deficiency did not constitute a failure to meet a regulatory requirement. The positioners on the main feed water regulating valves were not safety related and thus did not fall under the purview of 10 CFR 50, Appendix B, "Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants." No violation of regulatory requirements occurred. **FIN 05000311/2004004-05, Salem Unit 2 Manual Reactor Trip on July 15, 2004**

3. (Closed) LER 05000272/2004003-00 and Revision 1, Completion of Plant Shutdown to Comply with Technical Specifications - 3.6.1.1 "Containment Integrity"

   This LER discussed a plant shutdown to comply with Technical Specifications after a turbine building service water isolation valve, 1SW26, was discovered inoperable on June 02, 2004. 1SW26 had been rebuilt during maintenance and was determined to become more open when given a closed signal. 1SW26 isolates non-safety service water loads during a safety injection signal. Revision 1 to the LER described PSEG's root cause determination of the issue and corrective actions intended based on the root cause determination. The event described in this LER was reviewed by the inspectors in this inspection report section 4OA5.3 and was also an unresolved item in Inspection Report 05000272, 311/2004003 Section 1R19.1. This LER and revision 1 are closed.

4. (Closed) LER 05000311/2004004-00, Technical Specification Required Plant Shutdown Following Loss of 2B 230-Volt Vital Bus

   This LER discussed a plant shutdown on May 21, 2004, to comply with technical specifications after the 2B vital 230-volt A.C. bus supply transformer failed and tripped open the combined supply breaker to the 2B 460V and 230V vital buses. Operators performed a controlled plant shutdown to cold shutdown conditions. The event described in this LER was also reviewed by the inspectors in this inspection report Section 4OA5.2 and also in NRC Inspection Report 05000272, 311/2004-003 sections 1R14 and 1R20.2. This LER is closed.

5. (Opened) LER 05000272/2004001-00, As Found Value for Main Steam Safety Valve Lift Setpoint Exceeds Technical Specification Allowable Limit

   On April 9, 2004, PSEG received notice that a main steam system safety valve (MSSV) that was tested as a part of routine refuel outage testing failed its as-found lift setpoint test. The technical specification required actuation pressure was 1110 psig +/- 3%. The as-found lift setpoint was 1076 psig, -3.1% of the setpoint. The failed MSSV was replaced with a pre-tested and certified spare. The LER was reviewed by the inspectors. The inspectors verified that there were no current operability concerns with installed main steam safety valves. This LER is opened and requires further inspector review of PSEG's evaluation for the low lift setpoint.

6. (Closed) LER 05000272/2004004-00, Non-Essential Loads Not Isolated With One Chiller Inoperable as Required by Technical Specifications

   On July 21, 2004, the 11 chiller was taken out-of-service for planned maintenance. Technical Specification 3.7.10.a required non-essential heat loads be isolated and valves 1CH30 and 1CH151 were remotely closed from the main control room. Later the same day, operations personnel performed solid state protection system (SSPS) testing that caused, as expected, the control area ventilation system to realign and 1CH30 and 1CH151 to isolate. 1CH30 and 1CH151 were already isolated consistent with Technical Specification requirements. Operators restored the control area ventilation system at the conclusion of the SSPS testing to a normal lineup using procedure S1.OP-SO.CAV-0001, "Control Area Ventilation System Operation." The procedure directed valves 1CH30 and 1CH151 opened. The operators opened 1CH30 and 1CH151. The operators failed to notice a white caution tag on the control panel that was previously applied to administratively control 1CH30 and 1CH151 closed. Non-essential heat loads were unisolated for about seven hours until an oncoming reactor operator identified the incorrect position. TS 3.0.3 was entered and the operators immediately closed the valves to exit TS 3.0.3. PSEG entered this issue into the corrective action program as notification 20197693.

This finding was more than minor because it was associated with the configuration control attribute and it affected the Mitigating Systems Cornerstone objective. The inspectors determined that the finding was of very low safety significance (Green) using the Phase 1 SDP because the finding was not a design or qualification deficiency; it did not represent an actual loss of safety function of a single train for greater than the TS allowed outage time; and it did not screen as potentially risk significant for externally initiated core damage accident sequences. Although TS 3.0.3 was entered, the safety function of the control room chillers was maintained with 1CH30 and 1CH151 open. 1CH30 and 1CH151 would have automatically closed on a safety injection or loss of offsite power signal. This licensee-identified finding involved a violation of TS 3.7.10, Chilled Water System - Auxiliary Building Subsystem. The enforcement aspects of this violation are discussed in Section 4OA7. This LER is closed.

7. <u>(Closed) LER 05000311/2004005-00</u>, Auto Safety Injection Signal Not Unblocked Prior to Mode Change From 5 to 4

   On May 27, 2004, at approximately 6:30 a.m., a senior reactor operator identified by control panel indication that the Salem Unit 2 automatic safety injection signal was disabled while the plant was in Mode 4. The plant had transitioned to Mode 4 about five hours prior in preparation for startup from a refuel outage. The automatic SI signal had been disabled to facilitate refuel outage maintenance. Operators and technicians took immediate action and reinstated the automatic SI signal at 6:35 a.m.. This event was also described in NRC Inspection Report 05000272, 311/2004003, Section 4OA7; which was issued on August 11, 2004, as a Green, licensee identified NCV. This LER was reviewed by the inspectors and no additional findings of significance or violations of NRC requirements were identified. This LER is closed.

8. <u>Unit 2 Automatic Reactor Trip on September 9, 2004</u>: On September 9, 2004, Salem Unit 2 automatically tripped from 100% power due to a turbine trip associated with a generator protection trip. The inspectors responded to the main control room and verified stable hot standby plant conditions being maintained by the steam dump system. The inspectors observed plant chart recorders, interviewed control room operators, and reviewed main control room logs. The inspectors verified that the plant

and equipment response were as expected. No findings of significance were identified with the operators' response to the automatic reactor trip. PSEG entered this issue into the corrective action program as notifications 20202798 and 20203229. The inspectors used procedures 1-EOP-TRIP-1, "Reactor Trip or Safety Injection" and S1.OP-IO.ZZ-0008, "Maintaining Hot Standby" as criteria for evaluating the operators' response to this event.

4OA4 Cross Cutting Aspects of Findings

Section 4OA5.3 describes a finding for failure to provide adequate maintenance instructions to overhaul a turbine building service water isolation valve. This finding also has a human performance cross cutting aspect because maintenance technicians did not follow a match marking process or use other verification methods to assure that the MOV actuator was properly installed with respect to the disc position.

4OA5 Other

1. (Closed) URI 05000272/2004003-04: Failure of 11 and 15 Service Water Pumps Due to Degraded Auxiliary Switch Contacts in Power Supply Breaker Concern

During the Spring 2004, Salem Unit 1 refuel outage, the inspectors noted that the 11 and 15 service water pumps failed to start during mode operations surveillance testing due to degraded auxiliary switch contacts (a GE SBM control switch) in power supply breakers. This issue was left as an unresolved open item pending PSEG's completion of the SBM switch failure analysis and NRC further reviews of this analysis.

PSEG Service Corporation (Maplewood Testing Services) and GE Nuclear Energy (GE), the switch manufacturer, performed failure analyses of the failed switches. Both vendors concluded that the most probable cause of the SBM switch contact failure was due to the detachment of the silver tip button from the contact holder, resulting into an insufficient bonding area at the weld location. GE also reviewed this type of switch history record and found no similar failure occurred in the past. GE concluded that these two switch failures at Salem Unit 1 were an isolated failure. As a result of these failures experienced at Salem, GE issued a 10CFR Part 21 Communication (SC04-09) on July 12, 2004. This document recommended that potentially susceptible SBM switches (Q10AX-style) should be inspected during regularly scheduled circuit breaker maintenance to ensure that there is no indication of a coined contact tip detachment. To address this concern at Salem, PSEG inspected all the applicable SBM switches and found no other similar concern. The inspectors reviewed the PSEG performed analysis of the failed SBM switches and found the results reasonable and acceptable.

The inspector concluded that PSEG had appropriately addressed this concern and that no licensee performance deficiency had occurred. This item is closed.

2. (Closed) URI 05000311/2004003-08: Failure of 2B 4160/230V Vital Bus Transformer

On May 21, 2004, control room operators shutdown Salem Unit 2 in response to a failure of the 2B vital bus 230V transformer. This issue was unresolved pending the completion of PSEG's failure analysis of this transformer and further review of this analysis by the inspectors.

PSEG Contractor (Waukesha Electric Systems) completed the failure analysis and determined that all phases of transformer had a “phase to phase” fault. The failure analysis revealed that the possible cause of failure was due to overheating from an inrush current and loose terminal connections that accelerated the insulation deterioration. This breakdown was caused during initial fabrication of the transformer. Based on the “as found” condition and damage on the transformer, PSEG's contractor concluded that this transformer failure was isolated and random.

The inspector noted that PSEG had performed the scheduled preventive maintenance (54 month interval) on this transformer in October 2003. The PM required cleaning out all dust, dirt, and foreign particles from the coil, cores, insulators, etc. In addition, an inspection of coils, windings and wiring terminations was required to identify any evidence of burn damage, oxidation or insulation cracks. In addition, Doble testing was also performed following the maintenance to check the winding insulation condition. The inspectors reviewed the completed PM record of the failed transformer of October 2003, of inspection and testing results and the record indicated no concerns at that time.

On June 14, 2004, PSEG completed the root cause evaluation and determined that initially the fault originated in the 2nd phase of the transformer due to insulation break down. That fault resulted in a turn-to-turn short of high voltage windings, eventually resulting into faulting all three phases. The inspectors noted that the PSEG analysis included an extent of condition review (of remaining similar transformers), generic considerations, and a common mode failure concern. The inspectors found that PSEG had adequately addressed these concerns in the analysis and found no issue.

The inspector noted that PSEG had replaced the damaged transformer with a new spare safety-related transformer of slightly higher capacity (330 kVA versus 300kVA original). PSEG also performed applicable tests on affected equipment and associated cables.

Based on the above review of PSEG's corrective actions taken and no other failures experienced on similar transformers in the station and the vendor analysis determination that this failure was an isolated incident, the inspector concluded that PSEG had adequately addressed this concern and no licensee performance deficiency occurred. This item is closed.

3. <u>(Closed) URI 05000272/2004003-05</u>: Inoperable Turbine Building Service Water Isolation Valve

<u>Introduction</u>. A Green self-revealing NCV of 10 CFR 50 Appendix B, Criterion V, "Instructions, Procedures, and Drawings," was identified on June 02, 2004, for failure to establish maintenance instructions appropriate to the circumstances for corrective maintenance performed on the Unit 1 turbine building service water isolation valve,1SW26. Consequently, maintenance personnel reassembled the 1SW26 disc out of position in relation to the motor operated valve (MOV) actuator. This item was initially reviewed and documented in Inspection Report 05000272, 311 /2004003 Section 1R19.1 and remained open pending NRC review of PSEG's root cause evaluation.

<u>Description</u>. Turbine building (TB) service water (SW) isolation valve, 1SW26, was refurbished during refueling outage 1R16 and returned to service on May 07, 2004. On June 02, 2004, equipment operators subsequently noted a higher than expected lube oil outlet temperature on the 11 main turbine lube oil (MTLO) heat exchanger. The main turbine was operating at full speed, but was not loaded. Engineering personnel initiated a technical issues investigation in response to the unexpected 11 MTLO heat exchanger performance and discovered that 1SW26 was not operating properly. The 1SW26 butterfly valve disc and MOV actuator were oriented such that when 1SW26 was given a closed signal, the valve actually became more open.

1SW26 performs a safety function to automatically isolate the TB SW header following a loss of offsite power (LOOP) or safety injection (SI) signal. Control room operators determined that the most limiting applicable Technical Specification action statement was 3.6.1.1 for primary containment integrity. The failure mechanism of 1SW26 was such that some service water flow would be diverted from the containment fan coil units (CFCU) during an accident scenario. Without adequate flow to the CFCU's, voiding in the service water lines penetrating the containment could occur and subsequent water hammer could fail the service water lines and primary containment integrity. TS 3.6.1.1 required primary containment integrity to be restored within one hour or hot standby conditions established within the next six hours and cold shutdown within the following thirty hours. Control room operators appropriately established hot standby conditions at 4:24 p.m. and reestablished primary containment integrity at 9:41 p.m. on June 2, 2004, by closing and deenergizing upstream service water isolation valves 11SW20 and 13SW20.

PSEG personnel completed a root cause evaluation of the 1SW26 problem under order 70039380. The determined root cause was a failure to follow a match marking process to assure that the MOV actuator was properly installed with respect to the butterfly valve disc position. Only verbal communications were utilized between separate maintenance groups to establish the valve disc position for actuator installation. Technicians did not check or verify match marks to assure that the valve disc position prior to actuator installation was correct.

The root cause evaluators also determined that 1SW26 was most likely left in the closed position at the conclusion of valve work and prior to actuator installation, but rotated open due to leaking upstream isolation valves. The Jamesbury butterfly vendor manual provided precautions regarding this characteristic. These precautions were also not included in the maintenance instructions.

Analysis. PSEG's failure to provide adequate maintenance instructions to overhaul the 1SW26 was a performance deficiency. This performance deficiency also has a human performance cross cutting aspect. Specifically, maintenance technicians did not follow a match marking process or use other verification methods to assure that the MOV actuator was properly installed with respect to the disc position. 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 Initiating Events, Mitigating Systems and Barrier Integrity Cornerstone objectives.

In accordance with IMC 0609, Appendix A, the inspectors conducted a significance determination process (SDP) Phase 1 screening, determining that a Phase 2 analysis was required, because the performance deficiency affected three cornerstones. However, the inspectors were unable to evaluate the finding using Phase 2, because the Salem Plant Specific Risk Notebook did not evaluate loss of service water initiating events. As a result the Region I Senior Reactor Analyst (SRA) conducted a Phase 3 analysis.

The Phase 3 analysis determined that the finding was of very low safety significance (Green). This analysis used the Salem SPAR Revision 3.04, which was modified to update the service water system event trees by adding: 1SW26, 11SW20 and 13SW20; electrical dependencies; enhanced system train success criteria for situations where the TB header could not be isolated; and operator actions to isolate the turbine building loads and provide reactor coolant pump (RCP) seal cooling in the event of a loss of service water or station blackout initiating events. Valves 11SW20 and 13SW20 are located, one each, in the two parallel SW header supplies upstream of 1SW26. 11SW20 and 13SW20, similar to 1SW26, have a function to close automatically following a loss of offsite power (LOOP) or safety injection (SI) signal to isolate the TB SW header. Successful isolation requires either 1SW26 to close or both 11SW20 and 13SW20 to close to ensure proper service water flow is available for containment fan coil units, emergency diesel generators, and component cooling heat exchangers. The analysis also modified the charging pump and motor driven auxiliary feedwater (AFW) pump event trees to address room cooling dependencies related to service water coolers, based on a recent PSEG analysis of the ability of auxiliary building ventilation to supply necessary cooling. The model was also updated to include NUREG/CR 5496, "Evaluation of Loss of Offsite Power Events at Nuclear Power Plants: 1980 - 1996" loss of offsite power initiating event frequency data and non-recovery probabilities.

The assumptions used in the analysis were that 1SW26 would open if a SI signal occurred. The exposure time was approximately 341 hours and was from the point that residual heat removal was secured prior to plant startup on May 19, 2004, until June 2, 2004, when control room operators closed and deactivated 11SW20 and 13SW20 to isolate the TB SW header. The analysis determined an internal initiating event increase in core damage frequency of approximately 1.6E-8 over the 341 hour period. The dominant accident sequence involved a LOOP/station blackout (SBO) with failure to recover offsite power or a gas turbine generator prior to core damage.

Enforcement. 10 CFR 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," requires that activities affecting quality shall be prescribed by documented instructions, procedures, or drawings, of a type appropriate to the circumstances and shall be accomplished in accordance with these instructions, procedures, or drawings. Contrary to the above, on May 12, 2004, 1SW26 was incorrectly reassembled because maintenance work order 60044685 did not provide instructions to positively verify the valve disc position prior to MOV actuator installation. As a result, 1SW26 was not operable for closing on May 13, 2004, when hot shutdown conditions were entered until June 02, 2004, when 1SW26 was isolated with the closed and deenergized 11SW20 and 13SW20 valves. Because the failure to correctly assemble 1SW26 is of very low safety significance and has been entered into PSEG's corrective action program (order 70039380), this violation is being treated as a NCV, consistent with Section VI.A of the NRC Enforcement Policy. **(NCV 05000272/2004004-06, Incorrect Assembly of 1SW26)**

4OA6 Meetings, Including Exit

On August 12, 2004, a site visit was conducted by Mr. Ellis Merschoff, Deputy Executive Director of Operations - Reactor Programs for the NRC. During Mr. Merschoff's visit, he toured the Salem and Hope Creek plants, and met with PSEG managers.

On September 30, 2004, the resident inspectors presented the inspection results to Messrs. Mike Brothers and John Carlin. None of the information reviewed by the inspectors was considered proprietary.

4OA7 Licensee-Identified Violations

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

- Technical specification 3.7.10.a requires non-essential heat loads be isolated from the chilled water system within four hours with one chiller inoperable. Contrary to this requirement, the non-essential heat loads were unisolated for about seven hours from 12:05 p.m. to 6:58 p.m. on July 21, 2004. This issue was entered into PSEG's corrective action program as notification 20197693. The inspectors determined that this finding was of very low safety significance (Green) using the Phase 1 SDP because the finding was not a design or qualification deficiency; it did not represent an actual loss of safety function of a single train for greater than the TS allowed outage time; and it did not screen as potentially risk significant for externally initiated core damage accident sequences. The non-essential heat loads would have also automatically isolated on a safety injection or loss of offsite power signal.

ATTACHMENT: SUPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee personnel

K. Braendle, System Engineer, CCW System
M. Brothers, Vice President - Site Operations
W. Campbell, Salem Maintenance Manager
C. Fricker, Salem Plant Manager
R. Gary, Radiation Protection Manager
G. Gardener, System Engineer, SW System
G. Halnon, Salem Operations Manager
A. Khanpour, Salem System Engineering Manager
D. Kolasinski, System Engineer, EDG System
J. Melchionna, Program Manager, 89-13 program
T. Neufang, Radiation Protection Supervisor
J. Roeey, Mechnical Design
B. Thomas, Licensing
H. Wolfe, Hx Eddy Current Program
S. Zeigler, ALARA Specialist

LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

05000272/2004004-02	URI	1MS132 Repeat Malfunctions (Section 1R12.2)
05000272, 311/2004004-03	URI	Service Water Desilting Practices (Section 1R22)
05000272/2004004-04	URI	1CV52 Back Leakage (Section 1R22)
05000272/2004001-00	LER	As Found Value for Main Steam Safety Valve Lift Setpoint Exceeds Technical Specification Allowable Limit (Section 4OA3.5)

Opened/Closed

05000272/2004004-01	NCV	Untimely Problem Resolution for 125VD.C. Battery Charger Failures (Section 1R12.1)
05000311/2004004-05	FIN	Salem Unit 2 Manual Reactor Trip on July 15, 2004 (Section 4OA3.2)

05000272/2004004-06	NCV	Incorrect Assembly of 1SW26 (Section 4OA5.3)
05000311/2004006-00	LER	Salem Unit 2 Reactor Trip Due to a Malfunction of a Main Feedwater Regulating Valve (Section 4OA3.1)
05000311/2004007-00	LER	Salem Unit 2 Manual Reactor Trip Due to a Malfunction of a Main Feedwater Regulating Valve (Section 4OA3.2)
05000272/2004003-00 and 01	LER	Completion of Plant Shutdown to Comply With Technical Specifications - 3.6.1.1, "Containment Integrity" (Section 4OA3.3)
05000311/2004004-00	LER	Technical Specification Required Plant Shutdown Following Loss of 2B 230-Volt Vital Bus (Section 4OA3.4)
05000272/2004004-00	LER	Non-essential Loads Not Isolated With One Chiller Inoperable as Required by Technical Specifications (Section 4OA3.6)
05000311/2004005-00	LER	Auto Safety Injection Signal Not Unblocked Prior to Mode Change From 5 to 4 (Section 4OA3.7)

Closed

05000272/2004003-04	URI	Failure of 11 and 15 Service Water Pumps Due to Degraded Auxiliary Switch Contacts in Power Supply Breaker Concern (Section 4OA5.1)
05000311/2004003-08	URI	Failure of 2B 4160/230V Vital Bus Transformer (section 4OA5.2)
05000272/2004003-05	URI	Inoperable Turbine Building Service Water Isolation Valve (Section4OA5.3)

LIST OF DOCUMENTS REVIEWED

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

Section 1R04.1 documents reviewed:
UFSAR Section 9.5.4
Diesel Fuel Oil Mechanical Lineup (Trxn. No. 2559), dated 8/3/04

Diesel Fuel Transfer System Mechanical Lineup (Trxn. No. 2560), dated 8/3/04
Fuel Oil Drawings 205249 A 8761 - 29, 31, and 40
No. 11 Fuel Oil Storage Tank Analysis; dated 6/21/04, 3/22/04, 1/5/04
No. 12 Fuel Oil Storage Tank Analysis; dated 6/7/04, 3/8/04, 12/15/03
No. 21 Fuel Oil Storage Tank Analysis; dated 5/26/04, 3/1/04, 12/10/03
No. 22 Fuel Oil Storage Tank Analysis; dated 6/28/04, 4/5/04, 1/12/04
Main Fuel Oil Storage Tank Analysis; dated 7/5/04, 6/8/04, 5/10/04, 12/22/03
Salem Tank Truck Deliveries Analysis; dated 11/04/03, 11/08/03
WCD 4133318
S1.OP-ST.DG-0001, 1A Diesel Generator Surveillance Test, dated 5/24/04
S2.OP-ST.DG-0001, 2A Diesel Generator Surveillance Test, dated 5/27/04
S1.OP-ST.DG-0002, 1B Diesel Generator Surveillance Test, dated 5/8/04
S2.OP-ST.DG-0002, 2B Diesel Generator Surveillance Test, dated 7/1/04
S1.OP-ST.DG-0003, 1C Diesel Generator Surveillance Test, dated 4/11/04
S2.OP-ST.DG-0003, 2C Diesel Generator Surveillance Test, dated 6/15/04
S1.OP-ST.DG-004, 11 Fuel Oil Transfer System Operability Test, dated 6/2/04
S2.OP-ST.DG-004, 21 Fuel Oil Transfer System Operability Test, dated 5/27/04
S1.OP-ST.DG-005, 12 Fuel Oil Transfer System Operability Test, dated 7/1/04
S2.OP-ST.DG-005, 22 Fuel Oil Transfer System Operability Test, dated 6/4/04
S1.OP-ST.DG-0012, 1A Diesel Generator Endurance Run, dated 3/3/04
S2.OP-ST.DG-0012, 2A Diesel Generator Endurance Run, dated 8/18/03
S1.OP-ST.DG-0013, 1B Diesel Generator Endurance Run, dated 2/11/04
S2.OP-ST.DG-0013, 2B Diesel Generator Endurance Run, dated 9/29/03
S1.OP-ST.DG-0014, 1C Diesel Generator Endurance Run, dated 1/19/04
S2.OP-ST.DG-0014, 2C Diesel Generator Endurance Run, dated 6/13/03
S2.OP-SO.DG-0001, 2A Diesel Generator Operation, Rev. 31
S1.OP-SO.DG-0001, 1A Diesel Generator Operation, Rev. 29
S1.OP-SO.FO-0001, Emergency Diesel Fuel Oil System Operation, Rev. 8
S2.OP-SO.FO-0001, Emergency Diesel Fuel Oil System Operation, Rev. 10
Salem 1 Emergency Diesel Generators/Fuel Oil System Health Report, 2nd Quarter 2004
Salem 2 Emergency Diesel Generators/Fuel Oil System Health Report, 1st Quarter 2004
Information Notice 91-46: Degradation of Emergency Diesel Generator Fuel Oil Delivery Systems, dated 7/18/91
Information Notice 89-07: Failures of Small-Diameter Tubing in Control Air, Fuel Oil, and Lube Oil Systems Which Render Emergency Diesel Generators Inoperable, dated 1/25/89
IE Circular 77-15, Degradation of Fuel Oil Flow to the Emergency Diesel Generator, dated 11/28/77
NRC Regulatory Guide 1.137, Fuel-Oil Systems For Standby Diesel Generators, Rev. 1
Standard Specification for Diesel Fuel Oils (ASTM D975-03)
Risk-Informed Inspection Notebook For Salem Generating Station, Rev. 1
Condition report 20154535, 20137792, 20111852, 20112017, 20113279, 20113992, 20153587, 20157204, 20159161, 20160544, 20162895, 20174123, 20174312, 20175257, 20176395, 20198498, 20128613, 20155273, 20198868, 20199086, 20199188
Work order 30074774, 30077179, 30077688, 30104350, 30101584, 60047228

Section 1R04.2 documents reviewed:
S1.OP-SO.DG-0001, "1A Diesel Generator Operation," Rev. 29

S1.OP-SO.AF-0001, "Auxiliary Feedwater System Operation," Rev. 17
S1.OP-ST.AF-0003, "Inservice Testing - 13 Auxiliary Feedwater Pump," dated 7/16/04
S2.OP-SO.DG-0001, "2A Diesel Generator Operation," Rev. 31
S2.OP-SO.AF-0001, "Auxiliary Feedwater System Operation," Rev. 23
S2.OP-SO.FO-0001, "Emergency Diesel Fuel Oil System Operation," Rev. 10
Drawings 205249, 205236 and 205336

Section 1R06 documents reviewed:
Salem Updated Final Safety Analysis Report
Salem Individual Plant Examination of External Events
SC.MD-PM.ZZ-0036, "Watertight Door Inspection and Repair," Rev. 5
SC.OP-AB.ZZ-0001, "Adverse Environmental Conditions," Rev. 4
Inspection Report S-IR-6A5-001, Rev. 4, "Results of Annual Inspection Of Artificial Island Shoreline
Notifications: 20159188, 20199186, 20159082, 20204035, and 20202390
Work orders: 30038142, 30059212, 30085242, and 30103433

Section 1R07 documents reviewed
S1.OP-PT.SW-0017(Q), 12 Component Cooling Heat Exchanger Heat-transfer Performance Data Collection, Rev.14
S1.MD-PM.CC-003(Q), 12 Component Cooling Plate Heat Exchanger Inspection, Rev. 7
SC.MD-PM.CC-002(Q), Component Cooling Heat Exchangers # 11,21, and 22 Internal Inspection, Rev. 9
SC.MD-PM.DG-0017(Q), Diesel Generator Lube Oil and Jacket Water Cooler Internal Inspection, Rev. 4
S1.OP-PT.SW-0006(Q), Service Water Biofouling Monitoring Diesel Generators, Rev. 6
S2.PO-PT.SW-0006(Q), Service Water Biofouling Monitoring Diesel Generators, Rev. 7
SC.PO-AB.ZZ-0003(Q), Component Biofouling, Rev. 8

PM/CM Work Orders
11 Component Cooling Tube Heat Exchanger
    60035564, NUPM, S1CC-1CCE5, 11cchx Mounting Pedestal Cracking
    80067829, NUTS, S1CC-1CCE5, Create PM to Clean Debris From CC Hx man
12 Component Cooling Plate Heat Exchanger
    30106016, NUPM, S1CC-1CCE5, 12 CCE6 / Internal Inspection /89-013
    80059507, NUTS, S1CC-1CCE6, Need max D/P Limit in Ops Log 12B CCHX
21 and 22 Component Cooling Water Heat Exchanger
    30065641, NUPM, S2CC-2CCE5, 2CCE5: 21 CCHX/Performance Evaluation
    30095875, NUPM, S2CC-2CCE5, 2CCE5/Internal Inspection /89-013 LET
    30065642, NUPM, S2CC-2CCE6, 2CCE6: Performance evaluation/ 89-013
    30095978, NUPM, S2CC-2CCE6, 2CCE6/Internal Inspection/89-013LET
1B & C Diesel Generator Lube Oil Cooler
    30102109, NUPM, S1DG-1DAE2; 1YCD: 1B DG SERV H2O Biofouling MO
    30025391, NUPM, S1DG-1DAE3; 54M 1DAE3/1C DG Lo Internal Inspection
1A & C Diesel Generator Jacket Water Heat Exchanger
    30044260, NUPM, S1DG-1DAE58; 54M 1DAE58/Internal Inspection/ 89-013

80027603, NUTS, S1DG-1DAE60; Jacket Water Leak 1DAE60 Shell Side

Inspection and Test Results including Engineering Calculation/Analysis
Thermal Performance Test Package for test performed in April 2004, for 11 and 12 Component Cooling Heat Exchangers
Design and Procurement Data Sheets for Component Cooling Heat Exchangers
Calc. No. S-C-CC-MDC-1798, Component Cooling System Heat Exchangers

System Health Reports
Component Cooling System, Second Quarter, Units 1 & 2
Service Water System, Second Quarter, Units 1 & 2
Emergency Diesel Generators/Fuel Oil, Second Quarter, Units 1 & 2

Others
Generic Letter 89-13, Service Water System Problems Affecting Safety-Related Equipment
EPRI NP-7552, Heat Exchanger Performance Monitoring Guidelines
Selected Notification related to the CCW, SW, and EDG Cooling Systems

Section 1R14 documents reviewed:
S2.OP-IO.ZZ-0003, “Hot Standby to Minimum Load”
S2.OP-SO.CN-0002, “Steam Generator Feed Pump Operation”
S2.OP-AB.LOAD-0001, “Rapid Load Reduction”
S2.OP-AB.TRB-0001, “Turbine Trip Below P-9"

Section 1R19 documents reviewed:
S1.OP-ST.125-0001, “Electrical Power Systems 125VDC Distribution”
SC.MD-CM.125-0005, “125VDC Battery Cell Replacement”
NRC Regulatory Guide 1.128, “Installation Design and Installation of Large Lead Storage Batteries for Nuclear Power Plants”
IEEE-484, “IEEE Recommended Practice for Installation Design and Installation of Vented Lead-Acid Batteries for Stationary Applications”
IEEE-450, “IEEE Recommended Practice for Maintenance Testing, and Replacement of Vented Lead-Acid Batteries for Stationary Applications”
PSEG work order 60047666
Vendor technical document 309448, “Standby Battery Vented Cell Installation and Operating Instructions”

Section 1R20 documents reviewed:
Notifications 20196553, 20196666, 20196684, 20196790, 20196825, 20196943, and 2019735.

Section 2OS documents reviewed:
Quality Assurance (QA) Assessment Report 2004-0008
QA Assessment Report 2004-0018
QA Assessment Report 2004-0043
QA Assessment Monitoring Feedback 2004-0063
QA Assessment Monitoring Feedback 2004-0082

Focused Self-Assessment Report (FSAR) 80066418 0030
FSAR 80066418 0070
FSAR 80066418 0110
FSAR 80066418 0060
Radiation Protection Job Guide: Filter Activities, Rev 3
RWP 2004-0105
RP Surveys: 1-AUX-64-9H (7/29/04); 2-AUX-64-9H (8/24/04); 1-AUX-100-7H (8/5/04); 2-AUX-100-7H (7/15/04); 1-AUX-122-5E (4/12/04); 2-AUX-122-5E (7/1/04)
Notification Reports: 20185331; 20191467; 20162281; 20162409; 20165225

Section 4OA3 documents reviewed
Salem Unit 2 4kV/230-Volt S2230-2XFR2B4DBY Transformer Failure Root Cause Analysis dated June 14, 2004
Work Order No 30085100 for 54/M INSP. S2230-2XFR2B4DBY 2B Vital Bus
LER 2004-004-00 dated 5/21/04
SH.MD-GP.ZZ-0012(Q), Rev. 0,Meggering Electrical Equipment (non-Rotating)
SC.MD-PM.ZZ-0009(Q), Rev. 1,Miscellaneous Dry Type Transformer Maintenance Maplewood Testing Services Test Record of Transformer 2B 230V XFMR dated October 21, 2003

LIST OF ACRONYMS

AFW	Auxiliary Feedwater
ALARA	As Low As Is Reasonably Achievable
CCW	Component Cooling Water
CFCU	Containment Fan Coil Units
CFR	Code of Federal Regulations
DEP	Drill and Exercise Performance
EDG	Emergency Diesel Generator
GE	General Electric
GPM	Gallons Per Minute
HP	Health Physics
HX	Heat Exchanger
I/P	Current-to-Pneumatic
IMC	Inspection Manual Chapter
LOOP	Loss of Offsite Power
LOR	Licensed Operator Requalification
MOV	Motor Operated Valve
MTLO	Main Turbine Lube Oil
NCV	Non-cited Violation
NEI	Nuclear Energy Institute
NRC	Nuclear Regulatory Commission
NUMARC	Nuclear Management and Resources Council
ODs	Operability Determinations
PARS	Publicly Available Records
PI	Performance Indicator

PMT	Post Maintenance Testing
PSEG	Public Service Electric Gas
QA	Quality Assurance
RCP	Reactor Coolant Pump
ROP	Reactor Oversight Process
RP	Radiation Protection
RPM	Radiaiton Protection Manager
RWP	Radiation Work Permit
SBO	Station Blackout
SDP	Significance Determination Process
SG	Steam Generator
SI	Safety Injection
SRA	Senior Reactor Analyst
SSPS	Solid State Protection System
SW	Service Water
TB	Turbine Building
TS	Technical Specifications
UFSAR	Updated Final Safety Analysis Report
VHRA	Very High Radiation Area
WCD	Work Clearance Document