July 28, 2005

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

SUBJECT: SALEM NUCLEAR GENERATING STATION - NRC INTEGRATED INSPECTION REPORT 05000272/2005003 and 05000311/2005003

Dear Mr. Levis:

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

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

The report documents five NRC-identified findings and three self-revealing findings of very low safety significance (Green). Seven 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 findings as non-cited violations (NCVs) consistent with Section VI.A of the NRC Enforcement Policy. Additionally, licensee-identified violations which were determined to be of very low safety significance are 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 05000272/2005003 and 05000311/2005003
w/Attachment: Supplemental Information

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REGION I

Docket Nos:	05000272, 05000311
License Nos:	DPR-70, DPR-75
Report No:	05000272/2005003, 05000311/2005003
Licensee:	Public Service Enterprise Group Nuclear LLC
Facility:	Salem Nuclear Generating Station, Units 1 and 2
Location:	P.O. Box 236 Hancocks Bridge, NJ 08038
Dates:	April 1 - June 30, 2005
Inspectors:	J. Daniel Orr, Senior Resident Inspector George J. Malone, Resident Inspector Timothy L. O'Hara, Reactor Inspector Joseph T. Furia, Senior Health Physicist Paul Kaufman, Senior Reactor Inspector Anne Passarelli, Reactor Inspector Ram Bhatia, Reactor Inspector Frank J. Arner, Reactor Inspector Blake Welling, Senior Project Engineer Theodore Wingfield, Project Engineer Nancy McNamara, Emergency Preparedness Specialist Joel Wiebe, Project Engineer Andrea Kock, Allegations Specialist J. Persensky, Senior Technical Advisor - Human Factors
Approved By:	Eugene W. Cobey, Chief Projects Branch 3 Division of Reactor Projects

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SUMMARY OF FINDINGS

IR 05000272/2005003, 05000311/2005003; 04/01/2005 - 06/30/2005; Salem Nuclear Generating Station, Units 1 and 2; Equipment Alignment, Operability Evaluations, Inservice Inspection, Maintenance Effectiveness, Refueling and Outage Activities, Correction of Emergency Preparedness Weaknesses and Deficiencies, and Other Activities.

The report covered a 13-week period of inspection by resident inspectors, inspectors from the Division of Reactor Safety, regional projects inspectors, and inspectors and specialists in safety conscious work environment review. Seven 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. The inspectors identified a non-cited violation, in that, corrective actions established in July 1998 to identify, clean, and inspect Unit 2 reactor coolant system (RCS) instrument tubing were not implemented. Because these corrective actions were not implemented, four through-wall cracks were identified in RCS instrument tubing in April 2005. This finding was a non-cited violation of 10 CFR 50, Appendix B, Criterion XVI, “Corrective Actions.”

  Traditional enforcement does not apply because the issue did not have any actual safety consequences or potential for impacting the NRC's regulatory function, and was not the result of any willful violation of NRC requirements. This finding was more than minor because it was associated with the equipment performance attribute of the initiating events cornerstone and affected the objective to limit the likelihood of those events that upset plant stability and challenge critical safety functions during shut down as well as power operations. The inspectors determined that the finding was of very low safety significance (Green) using a Phase 1 screening in Appendix A of Inspection Manual Chapter 0609, “Determining the Significance of Reactor Inspection Findings for At-Power Situations.” It is expected that a tubing crack would result in an increase in RCS leakage, and operators would take action prior to exceeding Technical Specification limits for RCS leakage. Therefore, assuming worst case degradation, the finding would not result in exceeding the Technical Specification limit for identified RCS leakage and would not have likely affected other mitigation systems resulting in a total loss of their safety function. The performance deficiency had a problem identification and resolution (corrective action) cross cutting aspect. (Section 1R08.1)

Cornerstone: Mitigating Systems

- <u>Green</u>. A self-revealing finding was identified when the 22 charging pump was rendered unavailable to repair a degraded discharge check valve. Corrective actions from a similar occurrence on Unit 1 in June 2004 were not implemented in a timely manner to prevent recurrence. This finding was a non-cited violation of 10 CFR 50 Appendix B, Criterion XVI, "Corrective Actions."

  Traditional enforcement does not apply because the issue did not have any actual safety consequences or potential for impacting the NRC's regulatory function and was not the result of any willful violation of NRC requirements. This finding was more than minor because it was associated with the equipment performance attribute of the mitigating systems cornerstone and affected the objective to ensure the availability of systems that respond to initiating events to prevent undesirable consequences. The inspectors determined that the finding was of very low safety significance (Green) using a Phase 1 screening in Appendix A of Inspection Manual Chapter 0609, "Determining the Significance of Reactor Inspection Findings for At-Power Situations." The finding was not a design or qualification deficiency that resulted in a loss of function, did not result in an actual loss of system safety function, did not represent the actual loss of a safety function of a single train for greater than its Technical Specification allowed outage time, and was not screened as potentially risk significant from external events. The performance deficiency had a problem identification and resolution (corrective actions) cross cutting aspect. (Section 1R12)

- <u>Green</u>. The inspectors identified a non-cited violation, in that, the Unit 2 reactor sump room door was contrary to plant design. The configuration discrepancy reduced the available margin to identify and isolate a postulated service water leak from a containment fan coil unit prior to flooding safety-related equipment during loss-of-coolant accident conditions. The finding was a non-cited violation of 10 CFR 50, Appendix B, Criterion III, "Design Control."

  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 design control attribute of the mitigating systems cornerstone and affected the objective to ensure the reliability of systems that respond to initiating events to prevent undesirable consequences. The finding was of very low safety significance (Green) using a Phase 1 screening in Appendix A of Inspection Manual Chapter 0609, "Determining the Significance of Reactor Inspection Findings for At-Power Situations." The finding was a design control deficiency that did not result in a loss of function. (Section 1R15)

Cornerstone: Barrier Integrity

- <u>Green</u>. A self-revealing finding was identified when the 15 containment fan coil unit (CFCU) failed to start in high speed on May 24, 2005. PSEG determined that charging spring toggle switches on the high and low speed CFCU breakers were mis-positioned during a surveillance test on May 18, 2005. The configuration control error rendered the CFCU inoperable for 160 hours. The finding was a non-cited violation of 10 CFR 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings."

Traditional enforcement does not apply because the issue did not have any actual safety consequences or potential for impacting the NRC's regulatory function and was not the result of any willful violation of NRC requirements. This finding was more than minor because it was associated with the structure, system, or component performance attribute of the barrier integrity cornerstone and affected the cornerstone objective to provide reasonable assurance that containment barriers protect the public from radio nuclide releases caused by accidents or events. In accordance with IMC 0609, Appendix A, "Significance Determination of Reactor Inspection Findings for At-Power Situations," the inspectors were directed to IMC 0609, Appendix H, "Containment Integrity Significance Determination Process," because the finding represented an actual loss of defense-in-depth of a system that controls containment pressure. The finding was determined to be of very low safety significance (Green) because the Salem Units include a large, dry containment, and containment fan coil unit failures do not significantly contribute to large early release frequency (LERF). The performance deficiency had a human performance (personnel) cross cutting aspect. (Section 1R04)

- Green. The inspectors identified a non-cited violation for a failure to accomplish containment closure precautions in accordance with established procedures when the outage equipment hatch was blocked with a Sea-Van container during Unit 2 core alterations without a ready overhead crane. This finding was 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 consequence 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 human performance attribute of the barrier integrity cornerstone and affected the objective to provide reasonable assurance that containment barriers protect the public from radio nuclide releases caused by accidents or events. In accordance with IMC 0609, Appendix G, "Shutdown Operations Significance Determination Process," the inspectors conducted a Phase 1 SDP screening using checklist 4 and determined the finding to be of very low safety significance (Green). The finding did not increase the likelihood of a loss of RCS inventory, did not degrade the ability to terminate a leak path or add RCS inventory when needed, and did not degrade the ability to recover decay heat removal systems once lost. The performance deficiency had a human performance (personnel) cross cutting aspect. (Section 1R20)

- Green. A self-revealing finding was identified when a portion of the 12 service water accumulator outlet line was found nearly full of silt. Established corrective actions to inspect for silt on an eighteenth-month frequency were inappropriately deferred in April 2004. This finding was a non-cited violation of 10 CFR 50 Appendix B, Criterion XVI, “Corrective Actions.”

Traditional enforcement does not apply because the issue did not have any actual safety consequence 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 structure, system, or component (SSC) performance attribute of the barrier integrity cornerstone and affected the objective to provide reasonable assurance that containment barriers protect the public from radio nuclide releases caused by accidents or events. The inspectors determined that the finding was of very low safety significance (Green) using Inspection Manual Chapter (IMC) 0609, Appendix H, “Containment Integrity Significance Determination Process,” because the CFCUs are not important to large early release frequency, in that, the Salem units have large dry containments and the CFCUs only impact late containment failure and source terms. The performance deficiency had problem identification and resolution (evaluation and corrective action) cross cutting aspects. (Section 4OA2)

Cornerstone: Emergency Preparedness (EP)

- Green. The inspectors identified that PSEG did not complete an independent quality assurance audit to assess all elements of the emergency preparedness program as required by federal regulations. The finding was determined to be a non-cited violation 10 CFR 50.54(t), “Conditions of Licenses.”

  Traditional enforcement does not apply because the finding did not have any actual safety consequence 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 all attributes of the emergency preparedness cornerstone and affected the objective to ensure that the licensee is capable of implementing adequate measures to protect the health and safety of the public in the event of a radiological emergency. The inspectors determined that the finding was of very low safety significance (Green) using Appendix B of Inspection Manual Chapter 0609, "Emergency Preparedness Significance Determination Process, Sheet 1, Failure to Comply,” because it did not constitute a failure to meet an Emergency Preparedness planning standard or risk significant planning standard. (Section 1EP5)

Cornerstone: Miscellaneous

- Green. The inspectors identified a finding for several lapses in the use of the Executive Review Board (ERB) process. This finding involved not properly implementing a corrective action which had been intended to improve management effectiveness in detecting and preventing retaliation and the creation of a chilling effect. This finding was not a violation of regulatory requirements.

  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 if left uncorrected, it would lead to the potential for retaliation and a chilled work environment. This finding was of very low safety significance (Green), based on management review, because there was no direct impact on human performance or equipment reliability. The performance deficiency had problem identification and resolution (corrective action) and safety conscious work environment cross cutting aspects. (Section 4OA2.4)

B. Licensee Identified Violations

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

REPORT DETAILS

Summary of Plant Status

Unit 1 began the period at 100% power. Operators commenced a controlled plant shutdown on April 19, 2005, to repair a valve on a boron injection tank sample line and returned the plant to 100% power on April 22, 2005.

Unit 2 began the period at 100% power and then operators commenced a reactor shutdown and plant cooldown on April 6, 2005, to begin the fourteenth refueling outage (2R14). On May 14, 2005, 99.5% power was achieved following the refueling outage. Unit 2 remained at or near 99.5% power due to balance of plant limitations. No power reductions greater than 20% occurred for the duration of the inspection period.

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems and Barrier Integrity

1R01 Adverse Weather Protection (71111.01)

a. Inspection Scope (1 sample)

The inspectors reviewed PSEG's completed procedure SC.OP-PT.ZZ-0002, "Station Preparations for Seasonal Conditions," for hot weather conditions. Inspectors reviewed Unit 1 and Unit 2 system health reports for service water, auxiliary building ventilation and vital switchgear ventilation and interviewed responsible system engineers. Inspectors also reviewed operability determinations potentially impacted by hot weather and interviewed station personnel responsible for implementing severe weather preparations. Additional documents reviewed for this inspection activity are listed in the Supplemental Information attachment to this report.

On August 23, 2004, the NRC's Executive Director for Operations approved a deviation from the NRC's Action Matrix to provide a greater level of oversight for the Salem station than would typically be called for by the Action Matrix. One provision of the deviation memorandum provided for the enhancement of existing reactor oversight process baseline inspections. In accordance with this deviation, the following additional inspection samples were performed. The inspectors reviewed corrective action program notifications, work orders, and evaluations associated with service water bay silting. These documents were 20221277, 70047089, and 80028239.

b. Findings

No findings of significance were identified.

1R04 Equipment Alignment (71111.04)

a. Inspection Scope (4 partial walkdown samples)

Partial System Walkdown. The inspectors performed four partial system alignment inspections to verify risk significant systems were available during periods when redundant equipment was unavailable or relied upon to remove decay heat. On April 9, 2005, inspectors verified proper alignment of the 21 service water (SW) train while the 22 SW train was unavailable for planned maintenance during the 2R14 refueling outage. On April 28, 2005, inspectors conducted a partial system alignment of the Unit 2 spent fuel pool cooling (SFP) system following full core offload. Inspectors verified equipment and procedures were in place to mitigate a loss of SFP cooling, interviewed licensed operators, and reviewed SFP heat up rate calculations. On April 27 and on May 7, 2005, inspectors conducted partial system walkdowns of the Unit 2 residual heat removal (RHR) system. The April 27 walk down occurred prior to core reload and the May 7 walkdown was performed after securing the shutdown cooling lineup and prior to entering mode 3, “Hot Shutdown.” This walkdown verified proper emergency core cooling system configuration.

The inspectors also reviewed the circumstances surrounding a configuration control error associated with the 15 containment fan coil unit. The inspectors reviewed PSEG’s apparent cause evaluation and interviewed operators and individuals responsible for conducting the evaluation.

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

On August 23, 2004, the NRC’s Executive Director for Operations approved a deviation from the NRC’s Action Matrix to provide a greater level of oversight for the Salem station than would typically be called for by the Action Matrix. One provision of the deviation memorandum provided for the enhancement of existing reactor oversight process baseline inspections. In accordance with this deviation, the following additional inspection samples were performed. The inspectors reviewed corrective action program notifications, work orders, and evaluations associated with plant configuration issues. These documents were 20111599, 20219428, 70044453, 70044060, and 80076727.

b. Findings

Introduction. A self-revealing non-cited violation was identified when the 15 containment fan coil unit (CFCU) failed to start in high speed. The finding was of very low safety significance (Green) and a non-cited violation of 10 CFR 50, Appendix B, Criterion V, “Instructions, Procedures, and Drawings.”

Description. On May 24, 2005, at 11:47 pm, the 15 CFCU failed to start in high speed when control room operators shifted the CFCU from low speed to high speed. CFCUs are designed to operate in low fan speed for accident mitigation. High speed operation is used for containment cooling during normal plant operation. PSEG discovered that the high and low speed breaker charging spring motor toggle switches were both in the off position. Operators turned the switches to the 'on' position, and the charging springs charged. Operators started the 15 CFCU at 12:07 am on May 25, 2005, and declared the 15 CFCU operable.

PSEG's corrective action evaluation concluded that the most likely cause of the configuration error was that the charging spring toggle switches were erroneously placed in the off position during a surveillance activity. Specifically, on May 18, 2005, PSEG personnel performed S1.OP-ST.SW-0016, "Inservice Testing Service Water Accumulator Discharge Valves," which required the 15 CFCU low speed and high speed breaker control power to be disabled during the test.

<u>Analysis</u>. Breaker switches were not aligned as directed by procedure S1.OP-ST.SW-0016, "Inservice Testing Service Water Accumulator Discharge Valves," which resulted in 15 CFCU being inoperable for 160 hours and constituted a performance deficiency.

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 structure, system, or component performance attribute of the barrier integrity cornerstone and affected the cornerstone objective to provide reasonable assurance that containment barriers protect the public from radio nuclide releases caused by accidents or events. In accordance with IMC 0609, Appendix A, "Significance Determination of Reactor Inspection Findings for At-Power Situations," the inspectors were directed to IMC 0609, Appendix H, "Containment Integrity Significance Determination Process," because the finding represented an actual loss of defense-in-depth of a system that controls containment pressure. The finding was determined to be of very low safety significance (Green) because the Salem Units include a large, dry containment and containment fan coil unit failures do not significantly contribute to large early release frequency (LERF). The performance deficiency associated with this finding had a human performance (personnel) cross cutting aspect.

<u>Enforcement</u>. 10 CFR 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," requires, in part, that activities affecting quality shall be prescribed by documented procedures and shall be accomplished in accordance with these procedures. Contrary to the above, on May 24, 2005, PSEG discovered that surveillance procedure S1.OP-ST.SW-0016, "Inservice Testing Service Water Accumulator Discharge Valves," was not performed correctly, which resulted in the 15 CFCU charging spring toggle switches being out of position since May 18, 2005. Because this finding is of very low safety significance and has been entered into the corrective action program in notification 20240172, this violation is being treated as a NCV, consistent with section VI.A of the NRC Enforcement Policy. **(NCV 05000272/2005003-01, 15 Containment Fan Coil Unit Inoperable due to Configuration Control Error)**

1R05 Fire Protection (71111.05)

a. Inspection Scope (9 samples)

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

- Unit 2 Containment;
- Unit 1 and Unit 2 Auxiliary Feedwater Pump Areas;
- Unit 1 and Unit 2 Diesel Generator Areas;
- Unit 1 and Unit 2 Diesel Fuel Storage Areas; and
- Unit 1 and Unit 2 Charging Pump And Spray Additive Tank Areas.

On August 23, 2004, the NRC's Executive Director for Operations approved a deviation from the NRC's Action Matrix to provide a greater level of oversight for the Salem station than would typically be called for by the Action Matrix. One provision of the deviation memorandum provided for the enhancement of existing reactor oversight process baseline inspections. In accordance with this deviation, the following additional sample was performed. The inspectors reviewed corrective action program notifications, work orders, and evaluations associated with fire-watch deficiencies, degraded fire pump operation, and fire protection system water-hammer. These documents were 20231575, 20233533, 20231837, and 70046310.

b. Findings

No findings of significance were identified.

1R06 Flood Protection Measures (71111.06)

a. Inspection Scope (1 sample)

The inspectors evaluated internal flood protection measures for the Unit 1 and Unit 2 electrical penetration and battery rooms for both Salem Units. The areas were walked down to assess operational readiness of various features to protect vital electric power systems from internal flooding. These features included drainage systems, water-tight doors and barriers, and wall penetration seals. The inspectors also reviewed notifications associated with flood protection measures. Documents reviewed to verify proper flood prevention measures are listed in the Supplemental Information attachment to this report.

On August 23, 2004, the NRC's Executive Director for Operations approved a deviation from the NRC's Action Matrix to provide a greater level of oversight for the Salem station than would typically be called for by the Action Matrix. One provision of the deviation memorandum provided for the enhancement of existing reactor oversight process baseline inspections. In accordance with this deviation, the following additional inspection samples were performed. The inspectors reviewed corrective action program notifications, work orders, and evaluations associated with water-tight door control and risk assessment. These documents were 20226265, 20232494, 70045275, and 70047142.

b. Findings

No findings of significance were identified.

1R07 Heat Sink Performance (71111.07)

a. Inspection Scope (2 samples)

The inspectors reviewed performance data and interviewed the program manager responsible for implementation of NRC Generic Letter 89-13 to verify that potential heat exchanger or heat sink deficiencies were identified and that PSEG adequately resolved heat sink performance problems. Specifically, the inspectors observed internal inspections of the 22 component cooling (CC) heat exchanger and reviewed the completed 21 CC heat exchanger performance data. Inspectors evaluated trending data and verified equipment would perform satisfactorily under design basis conditions. The method of performance monitoring was compared against NRC Generic Letter 89-13, “Service Water System Problems Affecting Safety-Related Equipment,” and EPRI NP-7552, “Heat Exchanger Performance Monitoring Guidelines,” for conformance to these guidance documents. Additional documents reviewed are listed in the Supplemental Information attachment to this report.

On August 23, 2004, the NRC’s Executive Director for Operations approved a deviation from the NRC’s Action Matrix to provide a greater level of oversight for the Salem station than would typically be called for by the Action Matrix. One provision of the deviation memorandum provided for the enhancement of existing reactor oversight process baseline inspections. In accordance with this deviation, the following additional inspection samples were performed. The inspectors reviewed corrective action program notifications, work orders, and evaluations associated with service water materiel conditions and component cooling heat exchanger testing issues. These documents were 20233627, 20236701, 20224043, 20230095, and 70047710.

b. Findings

No findings of significance were identified.

1R08 Inservice Inspection Activities (71111.08)

1. Nondestructive Examination Evaluations

a. Inspection Scope (3 samples)

The inspectors reviewed selected samples of completed nondestructive examination (NDE) associated with repair or replacement activities and observed selected samples of NDE activities associated with the Salem Unit 2 refueling outage. The sample selections were based on the inspection procedure objectives and risk priority of those components and systems where degradation would result in a significant increase in risk of core damage. The observations and documentation reviews were performed to verify the activities were accomplished in accordance with the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code requirements. The inspectors also reviewed a sample of inspection reports and notifications initiated as a result of problems identified during in-service inspection (ISI) examinations. In addition, the inspectors reviewed PSEG's boric acid corrosion control program.

The inspectors observed the performance of four in-process NDE activities and reviewed documentation and examination reports for an additional thirteen NDE activities. The inspectors reviewed two welding activities on a pressure boundary and reviewed a repair package performed in accordance with the ASME Code during the previous operating cycle.

The inspectors observed ultrasonic tests performed on three residual heat removal system piping welds and the visual examination of the reactor pressure vessel (RPV) lower head instrumentation nozzles. The inspectors observed manual ultrasonic testing (UT) activities to verify the effectiveness of the examiner, process, and equipment.

The inspectors reviewed four samples of NDE evaluations which were initially rejected and subsequently accepted after evaluation. The inspectors also reviewed the radiographs and the examiners' interpretation of indications on five main steam system component welds.

The inspectors reviewed PSEG's report "Steam Generator Degradation Report for Salem Unit 2," dated March 31, 2005. This report documented the SG degradation measured in refueling outage 13, (Fall 2003) and provided the technical basis for steam generator inspections conducted during 2R14.

The inspectors reviewed the composition of pressurizer nozzle materials and verified that Temporary Instruction 2515/160, "Pressurizer Penetration Nozzles and Steam Space Piping Connections in US Pressurized Water Reactors," was not applicable to Salem Unit 2.

Additional documents reviewed during this inspection activity 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. In accordance with this deviation the inspectors examined additional ISI inspection data sheets and reviewed several notifications associated with ISI issues. The additional notifications and ISI data sheets reviewed are listed in the Supplemental Information attachment to this report.

b. Findings

1. Through-wall Leaks in Reactor Coolant System Instrument Tubing

Introduction. The inspectors identified a Green non-cited violation, in that, corrective actions established in July 1998 to identify, clean, and inspect Unit 2 reactor coolant system (RCS) instrument tubing were not implemented. Because these corrective actions were not implemented, four through-wall cracks were identified in RCS instrument tubing in April 2005. This finding was a non-cited violation of 10 CFR 50, Appendix B, Criterion XVI, "Corrective Actions."

Description. In July 1998, PSEG discovered nine leaks on RCS instrumentation tubing in the Unit 2 containment. Eight leaks were discovered in six separate RCS instrument tubing sections and one leak was discovered in the RCS sampling system tubing. PSEG determined that the cause was initiated as cracking on the outside of the tubing which progressed through wall to the inside surface by a transgranular stress corrosion cracking mechanism. This condition was reported via Licensee Event Report (LER) 05000311/1998007-00, on August 27, 1998. The root cause analysis further attributed the cracking to the presence of local residual stresses in the presence of contaminants, such as halogens, phosphate, and sulfate on the outside surface of the tubing. The analysis identified the source of the contaminants to be service water. Several corrective actions were specified to correct the causes and to assess the effectiveness of these actions. All corrective actions were planned for completion during the subsequent refueling outage in 1999. No documentation exists that the specified corrective actions were completed in 1999 or that the actions were continued after 1999. PSEG did not identify corrective actions to control the intrusion of contaminants through the service water system.

On April 4, 2005, PSEG discovered a through-wall leak on the instrument tubing for RCS flow transmitter 2FT416. This condition was discovered with the plant at 100% power. When discovered, PSEG initiated notification 20231322 to document the condition. The subsequent extent of condition review for this notification identified three additional leaks: two were through-wall tubing leaks (notifications 20233095 and 20236992) and one was a leak in a welded fitting (notification 20233096). PSEG determined that all of these leaks were caused by the same mechanism which caused the tubing leaks in 1998. PSEG also determined that service water contaminants existed on the tubing in 2005 and that they were a significant contributing factor.

Analysis. A performance deficiency was identified, in that, PSEG failed to implement corrective actions created in 1998 in response to several instrument tubing leaks. As a result, PSEG identified four through-wall leaks on RCS instrument tubes in April 2005.

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 finding was more than minor because it was associated with the equipment performance attribute of the initiating events cornerstone and affected the objective to limit the likelihood of those events that upset plant stability and challenge critical safety functions during shut down as well as power operations. The inspectors determined that the finding was of very low safety significance (Green) using a Phase 1 screening in Appendix A of Inspection Manual Chapter 0609, "Determining the Significance of Reactor Inspection Findings for At-Power Situations." It is expected that a tubing crack would result in an increase in RCS leakage, and operators would take action prior to exceeding Technical Specification limits for RCS leakage. Therefore, assuming worst case degradation, the finding would not result in exceeding the Technical Specification limit for identified RCS leakage and would not have likely affected other mitigation systems resulting in a total loss of their safety function. The performance deficiency had a problem identification and resolution (corrective action) cross cutting aspect.

Enforcement. 10 CFR 50, Appendix B, Criterion XVI, "Corrective Actions," requires, in part, that measures shall be established to assure that conditions adverse to quality, such as failures, malfunctions, deficiencies, and nonconformances are promptly identified and corrected. In the case of significant conditions adverse to quality, the measures shall assure that the cause of the condition is determined and corrective actions taken to preclude repetition. Contrary to the above, PSEG did not implement appropriate corrective actions to preclude the repetition of leaks in RCS instrument tubing identified in July 1998, which resulted in four additional through-wall leaks discovered on April 4, 2005. Because the finding was determined to be of very low significance and has been entered into PSEG's corrective action program (notification 20231322) this violation is being treated as a non-cited violation consistent with Section VI.A of the NRC Enforcement Policy. **(NCV 05000311/2005003-02, Through-Wall Leakage in Reactor Coolant System Instrument Tubing)**

2. Assessment of Reactor Coolant System Instrument Tube Structural Integrity

An unresolved item (URI) was identified in that further review is required of PSEG's evaluation regarding the structural integrity assessment performed by PSEG staff on an RCS tubing leak. On April 4, 2005, PSEG discovered a through-wall leak on the instrument tubing for RCS flow transmitter 2FT416. The instrument line is ASME code class 2. This condition was discovered with the plant at 100% power. PSEG concluded that the structural integrity of the tubing was acceptable without characterizing the failure mechanism. As a result of this evaluation, PSEG did not enter Technical Specification 3.4.11, Structural Integrity. This issue is unresolved pending inspector review of PSEG's evaluation of the structural integrity assessment. **(URI 05000311/2005003-03 Assessment of Reactor Coolant System Instrument Tube Structural Integrity)**

1R11 Licensed Operator Requalification Program (71111.11)

a. Inspection Scope (1 sample)

Requalification Activities Review by Resident Staff. On May 17, 2005, inspectors observed a simulator training scenario to assess operator performance, training effectiveness, and verify performance of a critique of operator performance by qualified evaluators. The scenario involved a failure of control area ventilation, an unplanned shutdown due to entry into Technical Specification 3.0.3, a small break loss of coolant accident, a steam generator atmospheric dump valve failure and a loss of low pressure injection. The inspectors verified operator actions were consistent with operating, alarm response, abnormal, and emergency procedures. The inspectors assessed simulator fidelity and verified that evaluators identified deficient operator performance where appropriate. Documents reviewed to verify proper operator performance and training effectiveness are listed in the Supplemental Information attachment to this report.

On August 23, 2004, the NRC's Executive Director for Operations approved a deviation from the NRC's Action Matrix to provide a greater level of oversight for the Salem station than would typically be called for by the Action Matrix. One provision of the deviation memorandum provided for the enhancement of existing reactor oversight process baseline inspections. In accordance with this deviation, the following additional inspection samples were performed. The inspectors reviewed corrective action program notifications, work orders, and evaluations associated with operator licensing issues. These documents were 20216735, 20229658, and 70045854.

b. Findings

No findings of significance were identified.

1R12 Maintenance Effectiveness (71111.12)

a. Inspection Scope (1 sample)

The inspectors reviewed maintenance effectiveness for the 21 and 22 charging pumps, specifically, issues related to the 2CV52 centrifugal charging pump discharge check valve. The inspectors reviewed corrective action program notifications documenting past operating problems, system health reports, maintenance rule performance criteria, and interviewed system engineers and maintenance rule program coordinators. The inspectors performed the reviews to determine if PSEG effectively characterized system performance. The inspectors referenced 10 CFR 50.65, "Requirements for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants," and NUMARC 93-01, "Industry Guideline for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants," to ascertain the acceptability of PSEG's maintenance rule application.

On August 23, 2004, the NRC's Executive Director for Operations approved a deviation from the NRC's Action Matrix to provide a greater level of oversight for the Salem station than would typically be called for by the Action Matrix. One provision of the deviation memorandum provided for the enhancement of existing reactor oversight process baseline inspections. In accordance with this deviation, the following additional inspection samples were performed. The inspectors reviewed corrective action program notifications, work orders, and evaluations associated with maintenance rule goal setting for the Unit 1 charging pumps. These documents were 20226651 and 70045157.

b. Findings

1. Unavailability of 22 Charging Pump due to 2CV52 Leakage

Introduction. A self-revealing non-cited violation was identified, in that, corrective actions were not implemented in a timely manner and resulted in unplanned unavailability of the 22 charging pump. This finding was of very low safety significance (Green) and a non-cited violation of 10 CFR 50, Appendix B, Criterion XVI, "Corrective Actions."

Description. On June 14, 2004, PSEG discovered that the discharge check valve (1CV52) for the 12 charging pump had approximately 20 gallons per minute backleakage while performing a surveillance test of the 13 charging pump. A function of the 1CV52 check valve was to prevent injection water from the 12 charging pump being diverted, should the 11 charging pump be idle. PSEG determined that the valve was not seating correctly due to a combination of wear and incorrect clearances on assembled valve components. At the time of the failure, only a non-intrusive test (radiography) was used to examine the physical condition of the valve internals. A subsequent corrective action item was to initiate a preventative maintenance task to open and inspect the valve internals on a periodic basis. 2CV52, an identical valve to 1CV52, but for the 22 charging pump, was scheduled to be inspected in 2008.

On May 13, 2005, while investigating a 23 charging pump flow deficiency, PSEG discovered that the discharge check valve for 22 charging pump (2CV52) had approximately 5 gallons per minute backleakage. PSEG subsequently discovered that the 2CV52 check valve seat had been etched by high pressure fluid in discrete locations providing leak paths across the valve disc. PSEG replaced the valve seat and returned the pump to service on May 14, 2005. The 22 charging pump was unavailable for 24 hours.

Analysis. PSEG identified in May 2004 that preventative maintenance tasks for internal inspections were needed on some chemical and volume control (CVC) check valves, including 2CV52. PSEG scheduled the first performance of this inspection on 2CV52 to occur in 2008. 2CV52 malfunctioned in May 2005. Untimely corrective actions rendered the 22 charging pump unavailable and was a performance deficiency.

The inspectors reviewed the impact of 2CV52 backleakage in regards to 21 charging pump operability and determined that the 21 charging pump remained operable. The 21 charging pump had a total of 6 gallons per minute margin in injection flow before it would be inoperable per S2.OP-ST.SJ-0016, “High Head Cold Leg Throttling Valve Flow Balance Verification,” performed on April 28, 2005. The 23 charging pump, albeit non-safety related, was also operable because sufficient injection capability margins existed.

Traditional enforcement does not apply because the issue did not have any actual safety consequences or potential for impacting the NRC’s regulatory function, and it was not the result of any willful violation of NRC requirements. This issue was more than minor because it was associated with the equipment performance attribute, and it affected the mitigating systems cornerstone objective to ensure the availability of systems that respond to initiating events to prevent undesirable consequences. The untimely corrective actions led to unavailability of the 22 charging pump. In accordance with IMC 0609, Appendix A, “Significance Determination of Reactor Inspection Findings for At-Power Situations,” the inspectors conducted a Phase 1 SDP screening and determined the issue to be of very low safety significance (Green). The finding was not a design or qualification deficiency, did not represent a loss of system safety function, did not represent an actual loss of safety function of a single train for greater than its Technical Specification Allowed Outage Time, did not represent an actual loss of safety function of one or more non-Technical Specification trains of equipment designated as risk significant per 10CFR50.65, for greater than 24 hours, and did not screen as potentially risk significant due to external events. The performance deficiency associated with the failure of 2CV52 has a problem identification and resolution (corrective action) cross cutting aspect.

Enforcement. 10 CFR 50, Appendix B, Criterion XVI, “Corrective Actions,” requires, in part, “Measures shall be established to assure that conditions adverse to quality, such as failures, malfunctions, deficiencies, and nonconformances are promptly identified and corrected. In the case of significant conditions adverse to quality, the measures shall assure that the cause of the condition is determined and corrective actions taken to preclude repetition.” Contrary to the above, PSEG did not preclude 2CV52 discharge check valve from malfunctioning in May 2005 after 1CV52, an identical valve and application, malfunctioned in May 2004. Corrective actions in May 2004 from the 1CV52 malfunction included a new preventive maintenance task to verify the functional capability of the CV52 valves, which was not performed on 2CV52 prior to its malfunction. Because this finding is of very low safety significance and has been entered into the corrective action program in notification 20246326, this violation is being treated as a NCV, consistent with section VI.A of the NRC Enforcement Policy. **(NCV 05000311/2005003-04, Unavailability of 22 Charging Pump due to Discharge Check Valve Leakage)**

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

a. Inspection Scope (6 samples)

The inspectors reviewed PSEG’s planning and risk assessments for six risk significant activities. The inspectors reviewed control room operating logs and PSEG probabilistic safety assessment risk evaluation forms, walked down protected equipment and maintenance locations, and interviewed involved personnel. These reviews were performed to determine whether PSEG properly assessed and managed plant risk and performed activities in accordance with applicable Technical Specification and work control requirements. The activities selected were based on plant maintenance schedules and systems that contributed to plant risk. The inspectors also referenced Regulatory Guide 1.182, “Assessing and Managing Risk Before Maintenance Activities at Nuclear Power Plants,” and PSEG procedure SH.OP-AP.ZZ-0027, “On-Line Risk Assessment.” For shutdown plant conditions, the inspectors referenced NC.OM-AP.ZZ-0001, “Outage Risk Assessment.” Additional documents reviewed are in the Supplemental Information attachment to this report. The following plant configurations were inspected:

- Unplanned Unit 1 power reduction to 84% to support condenser waterbox cleaning due to increased river detritus levels, loss of one source of offsite power as a result of planned maintenance on number 4 station power transformer, and control room ventilation aligned to the ‘maintenance mode’ on April 6, 2005;
- Unit 1 refuel outage on April 8, 2005, with reactor coolant water level just below the vessel flange, 1C vital electric switchgear out of service, the 22 nuclear service water header out of service and the 24 station power transformer out of service with emphasis on PSEG’s containment closure requirement at four hours;
- Planned unavailability of the 24, 25, and 26 service water pumps on April 8, 2005, during the Delaware River grassing season with emphasis on PSEG’s external events consideration for grassing;
- Planned unavailability of the 21 service water header and the 2A emergency diesel generator during Unit 2 core reload on April 27, 2005;
- Unplanned unavailability of the 2B EDG and planned maintenance on the gas turbine generator on May 17, 2005; and
- Planned unavailability of the 23 charging pump on May 23, 2005.

On August 23, 2004, the NRC’s Executive Director for Operations approved a deviation from the NRC’s Action Matrix to provide a greater level of oversight for the Salem station than would typically be called for by the Action Matrix. One provision of the deviation memorandum provided for the enhancement of existing reactor oversight process baseline inspections. In accordance with this deviation, the following additional inspection samples were performed. The inspectors reviewed corrective action program notifications, work orders, and evaluations associated outage risk management model improvements, and tagging errors resulting in increased plant risk. These documents were 20237753, 20228361, 70047505, and 70045721.

b. <u>Findings</u>

No findings of significance were identified. However, the issue on PSEG containment closure practices is unresolved pending further inspector review.

On April 6, 2005, PSEG began a Unit 2 refueling outage and 14 hours after the reactor shutdown, PSEG removed the containment equipment hatch. The inspectors questioned whether there was adequate time to establish containment integrity prior to fission product release between April 8 and April 10 if a loss of decay heat removal event occurred. During this period the reactor vessel was drained down to 3" below the flange resulting in a time to core boil of approximately 10 minutes. This condition existed until the reactor head and upper internals were removed at 2:30pm on April 10. The inspectors reviewed a PSEG evaluation that supported containment closure could be established in less than 4 hours, consistent with S2.OP-AB.CONT-001(Q) - Containment Closure. The inspectors noted that the procedure limited the removal of the equipment hatch only during reduced inventory operations, or when water level was about 3 feet below the vessel flange. Subsequent to inspector questions, PSEG performed an additional calculation that determined the time to core uncovery due to boiling was greater than five hours. PSEG concluded, because fission products would not be released until the core was uncovered, containment could be established in a timely manner. The inspectors questioned several aspects of this calculation, including the use of water volume in the cold leg loops located below the reactor vessel nozzles and whether the upper internal openings were designed such that they would permit sufficient steam flow to allow for draining of the reactor system into the fuel area of the vessel. PSEG entered these questions into the corrective action program for resolution (notification 20240276). This issue is unresolved pending inspector review of PSEG's recalculation on time to core uncovery and evaluation of whether containment integrity could have been established prior to the actual time frame for core uncovery and fission product release. **(URI 05000311/2005003-05, Containment Closure)**

1R14 <u>Operator Performance During Non-routine Evolutions and Events</u> (71111.14)

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

The inspectors observed control room operators during the performance of four non-routine plant evolutions. The inspectors reviewed operating procedures, attended pre-job briefs, 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. The following non-routine evolutions were observed:

- On April 5 and 6, 2005, the inspectors observed control room operators shut down Unit 2 from power operations to cold shutdown conditions to begin the fourteenth Unit 2 refueling outage;
- On April 9, 2005, the inspectors observed control room operators fill the Unit 2 refueling cavity;
- On May 10, 2005, the inspectors observed operators take Unit 2 critical, perform and observe portions of low power physics testing; and
- On 21 April 2005, the inspectors observed a Unit 1 startup from Mode 3 (Hot Standby) to Mode 2 (Startup). The inspectors monitored control room operations until power reached the point of adding heat.

On August 23, 2004, the NRC's Executive Director for Operations approved a deviation from the NRC's Action Matrix to provide a greater level of oversight for the Salem station than would typically be called for by the Action Matrix. One provision of the deviation memorandum provided for the enhancement of existing reactor oversight process baseline inspections. In accordance with this deviation, the inspectors reviewed corrective action program notifications 20225397, 20226269, 20227009, 20230295, 20235683, 20229658, and 20230729. The notifications were reviewed to determine if the PSEG was adequately addressing and resolving human performance issues in an appropriate time frame.

b. Findings

No findings of significance were identified.

1R15 Operability Evaluations (71111.15)

a. Inspection Scope (7 samples)

The inspectors reviewed seven operability determinations (ODs) and equipment issues. The reviews assessed technical adequacy, the use and control of compensatory measures, and compliance with the licensing and design basis. The inspectors' review included a verification that the operability determinations were made as specified by PSEG's procedure SH.OP-AP.ZZ-0108, "Operability Assessment and Equipment Control Program." The technical content of the ODs and the follow-up operability assessments were reviewed and compared to applicable Technical Specifications, the Updated Final Safety Analysis Report, and associated design and licensing basis documents. Additional documents reviewed are listed in the Supplemental Information attachment to this report. The inspectors also interviewed operations management, design engineers, and system engineers. The following operability issues were reviewed:

- Indications of shaft bellows leak on the Unit 1 pressurizer spray valve, 1PS3 (notification 20234698);
- Unit 1 boron injection tank sample line through wall leak (notification 20234255);
- 11 service water (SW) header operability following a failed in-service surveillance test on 13 SW pump with the cause of failure unknown (notification 20237973);
- Impact on Unit 2 containment flood level due to incorrect reactor sump room door design (notification 20181019);
- Operation of Unit 2 main steam isolation valve 23MS167 with unreliable hydraulic bypass valve (notification 20237542);
- Operation of 21 chiller with one of four loadable cylinders failed (notification 20231094); and
- 2B EDG output breaker plunger gap out-of-specification (notification 20232405/order 70046497).

On August 23, 2004, the NRC's Executive Director for Operations approved a deviation from the NRC's Action Matrix to provide a greater level of oversight for the Salem station than would typically be called for by the Action Matrix. One provision of the deviation memorandum provided for the enhancement of existing reactor oversight process baseline inspections. In accordance with this deviation, the inspectors reviewed corrective action program notifications 20223544, 20232156, 20238459, 20239536, 20236198, 20244123, 20244124, 20223561, and 20223562. The notifications were reviewed to determine if the PSEG was adequately addressing and resolving operability issues in an appropriate time frame.

b. Findings

Introduction. The inspectors identified that the Unit 2 reactor sump room door was contrary to plant design. The configuration discrepancy reduced the available margin to identify and isolate a postulated service water leak from a containment fan coil unit prior to flooding safety-related equipment during loss-of-coolant accident conditions. This finding was of very low safety significance (Green) and determined to be a non-cited violation of 10 CFR 50, Appendix B, Criterion III, “Design Control.”

Description. On July 8, 2004, the NRC opened an unresolved item (URI 05000272& 311/2004007-02) to review PSEG’s revised containment flooding calculation and the simulator sump level response. The inspectors questioned a plateau in containment level response during a loss of coolant accident as modeled for the simulator. Initially the inspectors learned that the plateau occurred when containment water level would reach the door threshold to the reactor sump room. Water was assumed to flow unimpeded to lower levels over the door threshold and through a wire mesh door. However, PSEG discovered through photographs that Unit 2 had a solid metal door and Unit 1 had a wire mesh door to the reactor sump room. The solid plate door was not consistent with design drawings.

The simulator modeling was based on the facility’s containment flooding calculation (S-C-A900-MDC-0082) which is common to both Salem units. The calculation assumed containment annulus level would stabilize at an 81' 9" elevation while additional water spilled freely through a wire mesh door to fill up the reactor sump room and reactor coolant drain tank pits. Calculation S-C-A900-MSE-0168 stated that containment flooding up to 84 feet could be tolerated without impacting safety-related equipment. Calculation S-C-A900-MSE-0168 also determined that the maximum level expected level was 83 feet 6 inches. Calculation S-C-ZZ-NDC-1651, further stated that a level of 83 feet 6 inches provided sufficient time for operators to identify and isolate a postulated 100 gpm SW leak from a CFCU before reaching 84 feet.

PSEG issued notification 20181019 and work order 70037479 to evaluate the condition. PSEG engineers issued calculation S-2-CAN-MEE-1867 on October 7, 2004. This calculation evaluated two alternate flow paths between the containment annulus and reactor sump room that were not credited in S-C-A900-MDC-0082. Specifically, the new calculation determined expected flow rates through two floor drains that connected the RCDT pit with the reactor sump room and the expected flow rate through a four by six-inch hole cut into the bottom right corner of the solid metal door. The new calculation concluded that the maximum flood level was still below 84 feet. The final calculated containment flood level was 83 feet 10.73 inches. 1.27 inches of margin was maintained for operators to identify and isolate the postulated SW leak from a CFCU.

PSEG installed a partial wire mesh door to the Unit 2 reactor sump room during the spring refuel outage in April 2005 under design change package (DCP) 80080153. URI 05000272&311/2004007-02 is closed.

Analysis. PSEG did not maintain the Unit 2 reactor sump room door per design requirements and consistent with calculations S-C-A900-MDC-0082 and S-C-ZZ-NDC-1651. Radiological controls photographs indicated the solid plate door was in service for about twenty years. PSEG's failure to maintain a wire mesh door to the Unit 2 reactor sump room consistent with the design basis was a performance deficiency.

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 wilful violation of NRC requirements. This finding was more than minor because it was associated with the design control attribute of the mitigating systems cornerstone and affected the objective to ensure the reliability of systems that respond to initiating events to prevent undesirable consequences. From the perspective of this issue, the containment structure design was relied on to hold a sufficient volume of water to prevent flooding of safety related equipment above 84 feet from a loss of coolant accident. The configuration discrepancy of the Unit 2 sump room door impacted the reliability of safety related equipment in a loss of coolant accident scenario. In accordance with IMC 0609, Appendix A, "Significance Determination of Reactor Inspection Findings for At-Power Situations," the inspectors conducted a Phase 1 SDP screening and determined that the finding was of very low safety significance (Green). The finding was a design control deficiency that did not result in a loss of function.

Enforcement. 10 CFR 50, Appendix B, Criterion III, "Design Control" requires, in part, that measures be established for the selection and suitability of application of materials, parts, equipment, and processes that are essential to the safety-related functions of the structures, systems, and components. Contrary to these requirements, PSEG did not select the Unit 2 reactor sump room door consistent with design basis drawings and calculations. The inconsistent solid plate door existed for about twenty years and was replaced in April 2005 with a suitable design and material. However, because the finding was of very low safety significance and has been entered into PSEG's corrective action program (notification 20181019), this finding is being treated as a non-cited violation, consistent with section VI.A of the NRC Enforcement Policy. **(NCV 05000311/2005003-06, Reactor Sump Room Door Design Deficiency)**

1R16 Operator Workarounds (71111.16)

a. Inspection Scope (2 samples)

Cumulative Operator Workaround Review. The inspectors conducted a cumulative review of operator workarounds for Salem Units 1 and 2. The review included interviews with various licensed and non-licensed operators. Inspectors reviewed Operations Night Orders, a 25% sample of identified operator concerns, operator turnover documents (for the Shift Manager, Shift Technical Adviser, and Reactor Operator) and all existing condition report operability determinations. This inspection sample included control room walkdowns for both Salem Units.

Selected Operator Workaround Review. The inspectors reviewed notifications, condition reports, and operability determinations associated with a deficiency in the hydraulic control circuit for a main steam isolation valve (23MS167). Manual action by operators could be necessary to fully open the main steam isolation valve if the valve drifted from the full open position. This selected operator workaround review was associated with notification 20237542. Additional documents reviewed are listed in the Supplemental Information attachment to this report.

On August 23, 2004, the NRC's Executive Director for Operations approved a deviation from the NRC's Action Matrix to provide a greater level of oversight for the Salem station than would typically be called for by the Action Matrix. One provision of the deviation memorandum provided for the enhancement of existing reactor oversight process baseline inspections. In accordance with this deviation, the inspectors reviewed corrective action program notifications 20234527, 20235024, and 20232636. The notifications were reviewed to determine if PSEG was adequately addressing and resolving operator concerns and workaround issues in an appropriate time frame.

b. Findings

No findings of significance were identified.

1R17 Permanent Plant Modifications (71111.17)

a. Inspection Scope (1 sample)

Inspectors reviewed permanent modifications to RHR valves 21RH18, RHR flow control valve, and 2RH20, RHR crosstie valve, under change number 80072690. This review included verification that integrated and system operating procedures addressed the RHR alignment during differing plant modes to satisfy Technical Specification requirements.

This modification installed Fisher Type 164A three-way switching valves on the 21RH18 and 2RH20 valve operators. This changed the failure mode of 21RH18 to fail-as-is from fail open and 2RH20 to fail-as-is from fail closed. This change was performed to prevent an overcooling event under a postulated loss of instrument air coincident with a safety injection signal.

On August 23, 2004, the NRC's Executive Director for Operations approved a deviation from the NRC's Action Matrix to provide a greater level of oversight for the Salem station than would typically be called for by the Action Matrix. One provision of the deviation memorandum provided for the enhancement of existing reactor oversight process baseline inspections. In accordance with this deviation, the inspectors reviewed corrective action program notifications 2019804, 20243149, and 20226579. The notifications were reviewed to determine if PSEG was adequately addressing and resolving design change package issues in an appropriate time frame.

b. Findings

No findings of significance were identified.

1R19 Post-Maintenance Testing (71111.19)

a. Inspection Scope (7 samples)

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

- Unit 1 FA-14 (1SJ6) local sample line RCS leakage repair;
- Unit 2 safety injection system valve, 2SJ60, packing repair;
- Unit 2 2A emergency diesel generator refueling outage maintenance window;
- Unit 2 21 charging pump speed increaser replacement;
- Unit 2 2C safeguards equipment control sequencer power supply repair;
- Unit 2 22RH19, residual heat removal crosstie valve, actuator motor maintenance during refueling outage 2R14; and
- Unit 2 23 charging pump discharge relief valve, 2CV114.

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

On August 23, 2004, the NRC's Executive Director for Operations approved a deviation from the NRC's Action Matrix to provide a greater level of oversight for the Salem station than would typically be called for by the Action Matrix. One provision of the deviation memorandum provided for the enhancement of existing reactor oversight process baseline inspections. In accordance with this deviation, the inspectors reviewed corrective action program notifications 20234832, 20235796, 20239754, and 20232434. The notifications were reviewed to determine if PSEG was adequately addressing and resolving post-maintenance testing issues in an appropriate time frame.

b. Findings

No findings of significance were identified.

1R20 Refueling and Other Outage Activities (71111.20)

a. Inspection Scope (1 sample)

The inspectors reviewed the schedule and risk assessment documents associated with the Salem Unit 2 refueling outage to confirm that PSEG appropriately considered risk, industry experience, and previous site-specific problems in developing and implementing a plan that assured maintenance of defense-in-depth. Prior to the refueling outage the inspectors reviewed PSEG's outage risk assessment to identify risk significant equipment configurations and determine whether planned risk management actions were adequate. During the refueling outage the inspectors observed portions of the shutdown and cooldown processes and monitored PSEG controls over the outage activities listed below. Documents reviewed for these activities are listed in the Supplemental Information attachment to this report.

The inspectors observed the Unit 2 shutdown and cooldown on April 5, 2005, and determined whether cooldown rates met Technical Specification (TS) requirements. Inspectors also inspected conditions within containment for indications of unidentified leakage and damaged equipment. The inspectors verified that PSEG managed the outage risk commensurate with the outage plan. Inspectors periodically observed refueling activities from the refueling bridge in containment and the spent fuel pool to verify refueling gates and seals were properly installed and determine whether foreign material exclusion boundaries were established around the reactor cavity. Core offload and reload activities were periodically observed from the control room and refueling bridge to verify whether operators adequately controlled fuel movements in accordance with procedures.

The inspectors verified that tagged equipment was properly controlled and equipment configured to safely support maintenance work. Specifically, inspectors walked down a service water system tagout for isolating one service water header (WCD 4152072) on April 9, 2005, and a charging system tagout for maintenance on 21 charging pump (WCD 4134621) on April 26, 2005. Equipment work areas were periodically observed to determine whether foreign material exclusion boundaries were adequate. During control room tours, the inspectors verified that operators maintained adequate reactor coolant system (RCS) level and temperature and that indications were within the expected range for the operating mode.

The inspectors determined whether offsite and onsite electrical power sources were maintained in accordance with TS requirements and consistent with the outage risk assessment. Periodic walkdowns of portions of the switchyard, onsite electrical buses and the emergency diesel generators (EDGs) were conducted during risk significant electrical configurations. The inspectors verified through routine plant status activities that the decay heat removal safety function was maintained with appropriate redundancy as required by TS and consistent with PSEG’s outage risk assessment. During core offload conditions, the inspectors periodically determined whether the fuel pool cooling system was performing in accordance with applicable TS requirements and consistent with PSEG's risk assessment for the refueling outage. Inspectors verified that equipment and procedures to mitigate a loss of spent fuel cooling were available and ready for use.

Reactor coolant system inventory controls and contingency plans were reviewed by the inspectors to determine whether they met TS requirements and provided for adequate inventory control. Inspectors reviewed procedures and observed portions of activities in the control room when the unit was in reduced inventory modes of operation, including mid-loop operations. Inspectors verified that level and core temperature measurement instrumentation was installed and operational. Calculations that provide time-to-boil information were also reviewed for RCS reduced inventory conditions as well as the spent fuel pool during high heat loads.

Containment status and procedural controls were reviewed by the inspectors during fuel offload and reload activities to verify that TS requirements and procedure requirements were met for containment. Specifically, the inspectors verified that during fuel movement activities personnel, materials and equipment were staged to close containment penetrations as assumed in the licensing basis.

On August 23, 2004, the NRC's Executive Director for Operations approved a deviation from the NRC's Action Matrix to provide a greater level of oversight for the Salem station than would typically be called for by the Action Matrix. One provision of the deviation memorandum provided for the enhancement of existing reactor oversight process baseline inspections. In accordance with this deviation, the inspectors reviewed corrective action program notifications 20235847, 20238016, 20233953, 20236471, 20237979, and 20237977. The notifications were reviewed to determine if PSEG was adequately addressing and resolving outage activity issues in an appropriate time frame.

b. Findings

Introduction. The inspectors identified a failure to accomplish containment closure precautions in accordance with established procedures when the outage equipment hatch was blocked with a Sea-Van container during Unit 2 core alterations without a ready overhead crane. This finding was of very low safety significance (Green) and determined to be a non-cited violation of 10 CFR 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings."

Description. On April 27, 2005, PSEG commenced core reload. Consistent with Technical Specification requirements, PSEG established controls ensuring that the containment equipment hatches and other openings could be closed within one hour. Procedure SC.MD-FR.CAN-0001, "Outage Equipment Hatch Installation, Removal, Seal Replacement and Door Manipulation for Containment Closure," provided instructions to maintain a running crane with an operator stationed while a Sea-Van blocked the outage equipment hatch (OEH). The procedure precaution facilitated timely Sea-Van removal and ensured Technical Specification requirements were satisfied during movement of irradiated fuel within the containment.

Shortly after core reload commenced at 5:42 p.m., the inspectors observed a Sea-Van rigged to a crane and blocking the OEH. The crane was not running. The crane operator was nearby, but was not informed that fuel movement was in progress. The inspectors called a manager in the Outage Control Center, and control room operators stopped fuel movement. PSEG recommenced fuel movement when the crane operator made the crane ready. The inspectors learned that a refuel superintendent did not understand all containment closure requirements and did not notify the yard superintendent responsible for crane operations that fuel movement was in progress.

Analysis. PSEG did not adequately establish all containment closure requirements during core alterations, which was a performance deficiency. The performance deficiency resulted from a failure to fully understand procedure instructions.

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 human performance attribute of the barrier integrity cornerstone and affected the objective to provide reasonable assurance that containment barriers protect the public from radio nuclide releases caused by accidents or events. In accordance with IMC 0609, Appendix G, "Shutdown Operations Significance Determination Process," the inspectors conducted a Phase 1 SDP screening using checklist 4 and determined the finding to be of very low safety significance (Green). The finding did not increase the likelihood of a loss of RCS inventory, did not degrade the ability to terminate a leak path or add RCS inventory when needed, and did not degrade the ability to recover decay heat removal systems once lost. The performance deficiency had a human performance (personnel) cross cutting aspect.

Enforcement. 10 CFR 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings" requires in part, that activities affecting quality shall be prescribed by documented 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 April 27, 2005, during fuel movement, PSEG did not follow a procedure precaution in SC.MD-FR.CAN-0001, "Outage Equipment Hatch Installation, Removal, Seal Replacement and Door Manipulation for Containment Closure," and did not maintain a running crane rigged to a Sea-Van blocking the OEH. However, because the violation is of very low safety significance (Green) and has been entered into the corrective action program (notification 20235815), this finding is being treated as a non-cited violation consistent with Section VI.A of the NRC Enforcement Policy. **(NCV 05000311/2005003-07, Containment Closure Requirements Not Satisfied)**

1R22 Surveillance Testing (71111.22)

a. Inspection Scope (9 samples)

The inspectors observed portions and reviewed procedures and test results of the following surveillance tests to verify that equipment was satisfactorily tested:

- S2.OP-ST.SSP-0001, "Manual Safety Injection - SSPS," on April 7, 2005;
- S2.OP-ST.RHR-0005, "Inservice Testing Residual Heat Removal Valves and Orifices," on April 9, 2005;
- S2.OP-PT.AF-0005, "23 Auxiliary Feedwater Pump Overspeed Trip Test Utilizing Compressed Air," on April 15, 2005;
- S2.IC-TR.SSP-0004, "Response Time of SSPS Logic - Reactor Trip and Safety Injection," on April 22, 2005;

- S2.OP-ST.SJ-0015, “Intermediate Head Hot Leg Throttling Valve Flow Balance Verification,” on April 26, 2005;
- S1.OP-ST.AF-0001, “Inservice Testing - 11 Auxiliary Feedwater Pump,” on April 26, 2005;
- S1.OP-ST.SW-0003, “Inservice Testing - 13 Service Water Pump,” on April 30, 2005;
- S2.IC-CC.RCS-0002, “Rod Position Indication System Signal Condition Module Calibration,” and S2.IC-ST.RCS-0001, “Rod Drop Time Measurement - Hot Full Flow,” on May 9, 2005; and
- S2.OP-ST.DG-0003, “2C Diesel Generator Surveillance Test,” on May 9, 2005.

On August 23, 2004, the NRC’s Executive Director for Operations approved a deviation from the NRC’s Action Matrix to provide a greater level of oversight for the Salem station than would typically be called for by the Action Matrix. One provision of the deviation memorandum provided for the enhancement of existing reactor oversight process baseline inspections. In accordance with this deviation, the inspectors reviewed corrective action program notifications 20221840, 20222929, 20225147, 20230095, and 20234160. The notifications were reviewed to determine if PSEG was adequately addressing and resolving testing issues in an appropriate time frame.

b. Findings

No findings of significance were identified.

Cornerstone: Emergency Preparedness [EP]

1EP2 Alert and Notification System Testing (71114.02)

a. Inspection Scope (1 sample)

An onsite review of the PSEG alert and notification system (ANS) was conducted to ensure that the system provided for prompt notification of the public for taking protective actions. The inspectors reviewed the following emergency preparedness (EP) procedures: NC.EP-DG.ZZ-0007(Z), “Siren Test Process,” and “Alert Notification System Daily Operational Guideline.” In addition, the inspectors interviewed the siren program technicians and reviewed maintenance and test records for calendar years 2003 and 2004 to determine if test failures were being properly addressed and sirens were routinely maintained. The inspection was conducted in accordance with NRC Inspection Procedure 71114, Attachment 02, and the applicable planning standard, 10 CFR 50.47(b)(5) and its related 10 CFR 50, Appendix E, “Emergency Planning and Preparedness for Production and Utilization Facilities,” requirements were used as reference criteria.

b. Findings

No findings of significance were identified.

1EP3 Emergency Response Organization Augmentation Testing (71114.03)

a. Inspection Scope (1 sample)

An onsite review of PSEG's emergency response organization (ERO) augmentation staffing requirements and the process for notifying the ERO was conducted to review the readiness of key staff to respond to an event and facility activation timeliness. The inspectors reviewed the communication pager test records from 2003 and 2004 and the associated corrective action notification reports. Finally, the Emergency Plan (E-Plan) qualification records for key ERO positions were reviewed to ensure that the ERO staff qualifications were current. The inspection was conducted in accordance with NRC Inspection Procedure 71114, Attachment 03, and the applicable planning standard, 10 CFR 50.47(b)(2), "Conditions of Licenses," and its related 10 CFR 50, Appendix E, "Emergency Planning and Preparedness for Production and Utilization Facilities," requirements were used as reference criteria.

b. Findings

No findings of significance were identified.

1EP4 Emergency Action Level and Emergency Plan Changes (71114.04)

a. Inspection Scope (1 sample)

During the period of January thru June 2005, the NRC has received and acknowledged the changes made to PSEG's E-Plan in accordance with 10 CFR 50.54(q),"Conditions of Licenses," which PSEG had determined resulted in no decrease in effectiveness to the E-Plan and which have concluded continue to meet the requirements of 10 CFR 50.47(b), "Emergency Plans" and 10 CFR 50, Appendix E, "Emergency Planning and Preparedness for Production and Utilization Facilities." The inspectors conducted a sampling review of the E-Plan changes which could potentially result in a decrease in effectiveness. This review does not constitute an approval of the changes and, as such, the changes are subject to future NRC inspection. The inspection was conducted in accordance with NRC Inspection Procedure 71114, Attachment 4, and the applicable requirements in 10 CFR 50.54(q) were used as reference criteria.

b. Findings

No findings of significance were identified.

1EP5 Correction of Emergency Preparedness Weaknesses and Deficiencies (71114.05)

a. Inspection Scope (1 Sample)

The inspectors reviewed corrective actions identified by PSEG pertaining to findings identified from drills and exercises conducted in 2003 and 2004. The associated corrective action notification reports were reviewed to determine the significance of the issues and whether repeat problems were occurring. Also, a review was conducted of PSEG's quality assurance (QA) program and associated assessment reports to ensure the licensee was able to assess the overall maintenance and effectiveness of the EP Program. In addition, the inspectors reviewed several 2003 and 2004 self-assessment reports and a detailed internal review of the ERO qualification/training program to assess the EP staff's ability to be self-critical for making improvements, avoiding complacency and/or degradation of their EP program. This inspection was conducted according to NRC Inspection Procedure 71114, Attachment 05, and the applicable planning standard, 10 CFR 50.47(b)(14), "Emergency Plans" and its related 10 CFR 50, Appendix E, "Emergency Planning and Preparedness for Production and Utilization Facilities," and 10 CFR 50.54(t), "Conditions of Licenses," requirements were used as reference criteria.

On August 23, 2004, the NRC's Executive Director for Operations approved a deviation from the NRC's Action Matrix to provide a greater level of oversight for the Hope Creek station than would typically be called for by the Action Matrix. One provision of the deviation memorandum provided for the enhancement of existing reactor oversight process (ROP) baseline inspections. In accordance with the deviation, the inspectors reviewed corrective action notifications 20179654, 20178926, 20213660, 20229104, 20202431, and 20181058 related to EP issues.

b. Findings

Introduction. The inspectors identified that PSEG did not complete an independent quality assurance audit to assess all elements of the EP program as required by federal regulations. The finding was of very low safety significance (Green) and determined to be a NCV of 10 CFR 50.54(t), "Conditions of Licenses."

Description. Since September 30, 2002, PSEG failed to adequately evaluate all the elements of the EP program, which includes an evaluation for adequacy of interfaces with state and local governments, to determine the overall effectiveness of the EP program. The review is required to be completed within a 24-month period.

PSEG's Quality Assurance program for conducting an EP program audit is described in the integrated master assessment plan (IMAP), EP-SM, revision 9. The audit focuses on six primary elements to meet the 10 CFR 50.54(t), "Conditions of Licenses," requirements. The elements included: (1) interface with state and local agencies; (2) drills and exercises; (3) plans and procedures; (4) facilities and equipment; (5) personnel readiness; and (6) performance indicators. Each primary element has specific evaluation criteria to assess the adequacy of the EP program.

The inspectors reviewed the assessment reports associated with three of the primary elements: drills and exercises, facilities and equipment and performance indicators. The reports were determined to be thorough, followed the IMAP audit criteria, and contained corrective actions. With respect to the remaining three elements, PSEG was not able to provide sufficient evidence or documentation to demonstrate that the audits had been completed as required. In addition, PSEG did not conduct interviews with EP representatives from state and local agencies to assess the interface with offsite agencies. Based on this information, the inspectors concluded that PSEG did not satisfactorily complete the 10 CFR 50.54(t), "Conditions of Licenses," EP program audit since the previous audit of September 2002.

Analysis. The performance deficiency involved a failure to complete an independent QA audit to assess all elements of the EP program as required by federal regulations. Traditional enforcement does not apply because the issue did not have any actual safety consequence or potential for impacting the NRC's regulatory function and was not the result of any willful 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 all attributes of the EP cornerstone and affected the objective to ensure that the licensee is capable of implementing adequate measures to protect the health and safety of the public in the event of a radiological emergency. Specifically, a failure to conduct an audit, which includes an assessment of the overall conduct and effectiveness of the EP program (both onsite and offsite), could impact the EP cornerstone.

The inspectors determined that the finding was of very low safety significance (Green) using Appendix B of Inspection Manual Chapter 0609, "Emergency Preparedness Significance Determination Process, Sheet 1, Failure to Comply," because it did not constitute a failure to meet an EP planning standard or risk significant planning standard.

Enforcement. 10 CFR 50.54(t), "Conditions of Licenses," requires, in part, that all elements of the EP program must be reviewed at least once every 24 months. It further requires that review must include an evaluation for adequacy of interfaces with state and local governments, and of licensee drills, exercises, capabilities, and procedures. Contrary to the above, from September 2002 to September 2004, PSEG did not complete the 10 CFR 50.54(t), "Conditions of Licenses," audit for determining the overall conduct and effectiveness of the EP program both onsite and offsite and to ensure that all program elements of the E-Plan were being properly implemented. This is a violation of 10 CFR 54.54(t), "Conditions of Licenses." However, because the finding was of very low safety significance (Green) and entered into corrective action program in notification 20232779, this violation is being treated as a NCV, consistent with Section VI.A. of the NRC Enforcement Policy. **(NCV 05000272&311/2005003-08, Failure to Complete 50.54(t) Audit)**

1EP6 Drill Evaluation (71114.06 - 1 sample)

a. Inspection Scope

The inspectors observed one EP drill from the control room Simulator and the Technical Support Center on May 18, 2005. The inspectors evaluated drill performance relative to developing classifications and implementation of notifications. The inspectors reviewed the Salem Event Classification Guides and Emergency Plans. The inspectors referenced Nuclear Energy Institute 99-02, "Regulatory Assessment Performance Indicator (PI)

Guidelines," and verified that PSEG correctly counted this drill's contribution to the NRC PI for Drill and Exercise Performance.

On August 23, 2004, the NRC's Executive Director for Operations approved a deviation from the NRC's Action Matrix to provide a greater level of oversight for the Salem station than would typically be called for by the Action Matrix. One provision of the deviation memorandum provided for the enhancement of existing reactor oversight process baseline inspections. In accordance with this deviation, the inspectors reviewed corrective action program notifications 20229105 and 20229104. The notifications were reviewed to determine if PSEG was adequately addressing and resolving emergency preparedness issues in an appropriate time frame.

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 (8 samples)

The inspectors reviewed radiation work permits (RWPs) used to access high radiation areas and identified what work control instructions or control barriers were specified. The inspectors reviewed electronic personal dosimeter (EPD) alarm setpoints, both integrated dose and dose rate, for conformity with survey indications and plant policy.

Based on PSEG's schedule of work activities, the inspectors selected three jobs performed in radiation areas, airborne radioactivity areas, or high radiation areas (<1 R/hr) for observation: reactor vessel head replacement, steam generator in-service inspection, and reactor defueling. The inspectors reviewed radiological job requirements (RWP requirements and work procedure requirements), observed job performance with respect to these requirements, and determined that radiological conditions in the work area were adequately communicated to workers through briefings and postings.

During job performance observations, the inspectors 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 (factor of 5 or more), the inspectors reviewed the application of dosimetry to effectively monitor exposure to personnel and verified PSEG controls were adequate.

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

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

On August 23, 2004, the NRC's Executive Director for Operations approved a deviation from the NRC's Action Matrix to provide a greater level of oversight for the Salem station than would typically be called for by the Action Matrix. One provision of the deviation memorandum provided for the enhancement of existing reactor oversight process baseline inspections. In accordance with this deviation, the inspectors reviewed corrective action program notifications 20231746, 20231744, and 20231789. The inspectors validated that radiological access control issues were being resolved through notification reviews and discussions with the station radiation protection personnel.

b. Findings

No findings of significance were identified.

2OS2 ALARA Planning and Controls (71121.02)

a. Inspection Scope (9 samples)

Based on scheduled work activities and associated exposure estimates, the inspectors selected three of the highest exposures that were in progress work activities in radiation areas, airborne radioactivity areas, or high radiation areas for observation. The inspectors evaluated PSEG's use of ALARA controls for these work activities by performing the following: evaluation of PSEG's use of engineering controls to achieve dose reductions, verified that procedures and controls were consistent with PSEG's ALARA reviews, verified that sufficient shielding of radiation sources was provided for, and verified that dose expended to install/remove shielding did not exceed the dose reduction benefits afforded by the shielding.

The inspectors reviewed the ALARA work activity evaluations, exposure estimates, and exposure mitigation requirements for the three jobs listed above and determined that PSEG established procedures, engineering and work controls based on sound radiation protection principles to achieve occupational exposures that were ALARA.

The inspectors compared the results achieved (dose rate reductions, person-rem used) with the intended dose established in PSEG's ALARA planning for these work activities.

The inspectors reviewed PSEG's method for adjusting exposure estimates, or re-planning work, when unexpected changes in scope or emergent work were encountered.

On August 23, 2004, the NRC's Executive Director for Operations approved a deviation from the NRC's Action Matrix to provide a greater level of oversight for the Salem station than would typically be called for by the Action Matrix. One provision of the deviation memorandum provided for the enhancement of existing reactor oversight process baseline inspections. In accordance with this deviation, the inspectors reviewed corrective action program notifications 20231684, 20232142, and 20231746. The inspectors validated that ALARA issues were being resolved through notification reviews and discussions with the station ALARA personnel.

b. Findings

No findings of significance were identified.

2OS3 Radiation Monitoring Instrumentation (71121.03)

a. Inspection Scope (1 sample)

The inspectors conducted a review of selected radiation protection instruments located in the radiologically controlled area (RCA). Items reviewed were: verification of proper function, certification of appropriate source checks, and calibration for those instruments used to ensure that occupational exposures were maintained in accordance with 10 CFR 20.1201.

On August 23, 2004, the NRC's Executive Director for Operations approved a deviation from the NRC's Action Matrix to provide a greater level of oversight for the Salem station than would typically be called for by the Action Matrix. One provision of the deviation memorandum provided for the enhancement of existing reactor oversight process baseline inspections. In accordance with this deviation, the inspectors reviewed corrective action program notifications 20231788 and 20230454. The inspectors validated that radiological instrument issues were being resolved through notification reviews and discussions with the station radiological instrument personnel.

b. Findings

No findings of significance were identified.

Cornerstone: Public Radiation Safety [PS]

2PS3 Radiological Environmental Monitoring Program (71122.03)

a. Inspection Scope (9 samples)

The inspectors reviewed the current Annual Environmental Monitoring Report, and PSEG assessment results, to verify that the Radiological Environmental Monitoring Program

(REMP) was implemented as required by Technical Specifications and the offsite dose calculation manual (ODCM). The review included changes to the ODCM with respect to environmental monitoring commitments in terms of sampling locations, monitoring and measurement frequencies, land use census, interlaboratory comparison program, and analysis of data. The inspectors also reviewed the ODCM to identify environmental monitoring stations. In addition, the inspectors reviewed: PSEG self-assessments and audits, licensee event reports, inter-laboratory comparison program results, the UFSAR for information regarding the environmental monitoring program and meteorological monitoring instrumentation, and the scope of the audit program to verify that it met the requirements of 10 CFR 20.1101 (c).

The inspectors walked down six air particulate and iodine sampling stations; four milk sampling stations; one sediment station; and twenty-three thermoluminescent dosimeter (TLD) monitoring locations and determined that they were located as described in the ODCM and determined the equipment material condition to be acceptable. The inspectors also observed the receipt by PSEG of six sediment samples from a vendor.

The inspectors observed the collection and preparation of a variety of environmental samples (listed above) and verified that environmental sampling was representative of the release pathways as specified in the ODCM and that sampling techniques were in accordance with procedures.

Based on direct observation and review of records, the inspectors verified that the meteorological instruments were operable, calibrated, and maintained in accordance with guidance contained in the UFSAR, NRC Safety Guide 23, and PSEG procedures. The inspectors verified that the meteorological data readout and recording instruments in the control room and at the tower were operable.

The inspectors reviewed each event documented in the Annual Environmental Monitoring Report which involved a missed sample, inoperable sampler, lost TLD, or anomalous measurement for the cause and corrective actions. The inspectors conducted a review of PSEG's assessment of any positive sample results.

The inspectors reviewed significant changes made by PSEG to the ODCM as the result of changes to the land census or sampler station modifications since the last inspection. The inspectors also reviewed technical justifications for changed sampling locations and verified that PSEG performed the reviews required to ensure that the changes did not affect its ability to monitor the impacts of radioactive effluent releases on the environment.

The inspectors reviewed the calibration and maintenance records for air samplers. The inspectors reviewed: the results of PSEG's interlaboratory comparison program to verify the adequacy of environmental sample analyses performed by PSEG; PSEG's quality control evaluation of the interlaboratory comparison program and the corrective actions for any deficiencies; the determination of any bias to the data and the overall effect on the REMP; and quality assurance (QA) audit results of the program to determine whether PSEG's program met the Technical Specification/ODCM requirements. The inspectors verified that the appropriate detection sensitivities with respect to Technical Specification/ODCM requirements were utilized for counting samples and reviewed the results of the quality control program, including the interlaboratory comparison program, to verify the adequacy of the program.

The inspectors observed several locations where PSEG monitored potentially contaminated material leaving the radiologically controlled area (RCA), and inspected the methods used for control, survey, and release from these areas, including observing the performance of personnel surveying and releasing material for unrestricted use and verifying that the work was performed in accordance with plant procedures.

The inspectors verified that the radiation monitoring instrumentation was appropriate for the radiation types present and was calibrated with appropriate radiation sources. The inspectors reviewed PSEG's criteria for the survey and release of potentially contaminated material; verified that there was guidance on how to respond to an alarm which indicates the presence of licensed radioactive material; and reviewed PSEG's equipment to ensure the radiation detection sensitivities were consistent with the NRC guidance contained in IE Circular 81-07 and IE Information Notice 85-92 for surface contamination, and HPPOS-221 for volumetrically contaminated material. The inspectors also reviewed PSEG's procedures and records to verify that the radiation detection instrumentation was used at its typical sensitivity level based on appropriate counting parameters and verified that PSEG has not established a "release limit" by altering the instrument's typical sensitivity through such methods as raising the energy discriminator level or locating the instrument in a high radiation background area.

The inspectors reviewed PSEG's Licensee Event Reports, Special Reports, and audits related to the radiological environmental monitoring program performed since the last inspection of this area. The inspectors determined that identified problems were entered into the corrective action program for resolution. The inspectors also reviewed corrective actions affecting environmental sampling, sample analysis, or meteorological monitoring instrumentation.

On August 23, 2004, the NRC's Executive Director for Operations approved a deviation from the NRC's Action Matrix to provide a greater level of oversight for the Hope Creek station than would typically be called for by the Action Matrix. One provision of the deviation memorandum provided for the enhancement of existing reactor oversight process baseline inspections. In accordance with this deviation, the inspectors reviewed corrective action program notification 20177320 and conditions adverse to quality 10120413, 10116875, 10114829, 10114298, 10112512, 10112513, 10107239, 10105487, and 10100299. The inspectors validated that REMP issues were being resolved through notification reviews and discussions with the REMP program personnel.

b. Findings

No findings of significance were identified.

4. OTHER ACTIVITIES [OA]

4OA1 Performance Indicator (PI) Verification

b. Inspection Scope (71151 - 3 Samples)

The inspectors reviewed PSEG's procedure for developing the data for the EP PIs which are: (1) Drill and Exercise Performance (DEP); (2) ERO Drill Participation; and (3) ANS Reliability. The review covered the period of September 2004 to April 2005. The inspectors also reviewed PSEG's 2004 and 2005 drill and exercise reports, training records and ANS testing data to verify the accuracy of the reported data. The review was conducted in accordance with NRC Inspection Procedure 71151. The acceptance criteria used for the review were 10 CFR 50.9 and NEI 99-02, Revision 1, Regulation Assessment Performance Indicator Guideline.

c. Findings

No findings of significance were identified.

4OA2 Identification and Resolution of Problems (71152)

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

On August 23, 2004, the NRC's Executive Director for Operations approved a deviation from the NRC's Action Matrix to provide a greater level of oversight for the Salem station than would typically be called for by the Action Matrix. One provision of the deviation memorandum provided for the enhancement of existing reactor oversight process baseline inspections. In accordance with this deviation, the inspectors reviewed PSEG's business plan commitments to improve the corrective action program, safety conscious work environment, leadership effectiveness and work management. The inspectors assessed satisfactory completion of the selected business plan objectives. Specifically the inspectors reviewed:

- CAP.01.PS.02.03, Implementation of Operability Determination Recommendations;
- SCWE.02.OPS.01.02, Ensure Industrial Safety Issues are Promptly Resolved;
- LE.04.NT.01.03, Trend Behaviors by Work Group; and
- WM.01.PS.01.03, PM Optimization Plan.

4. Annual Sample Review (3 samples)

a. Inspection Scope

The inspectors reviewed PSEG's evaluation and corrective actions associated with the following three issues:

Silt in Service Water Piping. The inspectors selected for detailed review PSEG's corrective actions and evaluations on service water lines that on occasion experienced silting. Specifically, the inspectors reviewed issues associated with containment fan coil unit (CFCU) accumulator lines and service water headers to the emergency diesel generators.

The inspectors reviewed notifications 20237971 and 20236105 documenting the CFCU accumulator silting issue. Order 30031439 was also reviewed to understand PSEG's deferral basis for a planned open and inspect on the Unit 1 CFCU accumulator line during a Unit 1 refuel outage in April 2004 (1R16). The inspectors judged the adequacy of the apparent cause and extent-of-condition evaluations and verified appropriate corrective actions were identified and prioritized. The inspectors interviewed cognizant engineers and walked down affected SW piping. Corrective action completion was verified through the interviews and walkdowns.

Technical Support Center Staffing. The inspectors reviewed corrective action program notification 20232024 associated with the ability of PSEG to adequately staff the Salem technical support center (TSC) within the requirements of PSEG's Emergency Plan and guidance contained in NUREG-0654, "Criteria for Preparation and Evaluation of Radiological Emergency Response Plans and Preparedness in Support of Nuclear Power Plants," Table B-1. The inspectors observed an "off-hours" unannounced drill performed on June 2, 2005, and observed the staffing and activation of the TSC. The inspectors also reviewed applicable documents as listed in the Supplemental Information attachment to this report.

Low Auxiliary Building Ventilation Flows. URI 05000272&311/2005002-02, Low Auxiliary Building Ventilation Flows, was opened pending review of PSEG's past operability determination associated with a condition where the Unit 1 and Unit 2 auxiliary building ventilation flow balance was not consistent with design assumptions. Specifically, the system was degraded because some field measurements were less than the originally designed air flows. The inspectors reviewed the engineering analysis to verify the system remained operable. The inspectors also reviewed associated condition reports 70040391 and 70045063, and the Salem Units 1&2 auxiliary building ventilation design/flow-balance action plan, revision 4, to evaluate whether reasonable corrective actions had been performed or planned to resolve the issue. The inspectors reviewed current operability guidance which had been translated into procedure SH.OP-DL.ZZ-0027, Form 5, "Salem Additional Reading/Operator Action Log." This review was performed to ensure procedure guidance was consistent with the latest engineering analysis of the condition.

b. Findings and Observations

1. Silt in Service Water Piping

Introduction. A self-revealing finding was identified when a portion of the 12 service water accumulator outlet line was found nearly full of silt. Established corrective actions to inspect for silt on an eighteenth-month frequency were inappropriately deferred in April 2004. This finding was of very low safety significance (Green) and was a non-cited violation of 10 CFR 50, Appendix B, Criterion XVI, "Corrective Action."

Description. Each Salem unit has five CFCUs to support containment cooling during normal and post-accident operation. Two service water accumulators for each Salem unit are connected to the CFCU SW lines, are normally isolated, but inject a large volume of pressurized water during a loss of offsite power event to maintain the SW piping full. A service water accumulator is provided for each SW header and supports two CFCUs. One CFCU is actually supported by both SW accumulators and isolation between the two accumulators is provided by dual check valves. Because the service water accumulators are normally isolated, the potential for silt buildup in dead legs exists. The physical configuration of the 12 SW accumulator and the 22 SW accumulator are nearly identical and are particularly susceptible to silt buildup at the outlet check valves, 12SW536 and 22SW536.

On April 29, 2005, engineers performed a preventive maintenance (PM) activity to open and inspect a piping leg, at 22SW536 from the 22 SW accumulator to the 24 and 25 CFCUs. The engineers discovered the piping at 22SW536 nearly full of silt. The preventive maintenance activity existed because silt was known to accumulate in this dead leg. The engineers established an eighteen-month periodicity for the preventive maintenance activity documenting the concern in notification 20163686 on October 23, 2003. A previous periodicity of thirty-six months was judged inadequate as the SW line was full of silt.

On May 4, 2005, engineers presented a Unit 2 service water system evaluation to the Station Operations Review Committee (SORC). The SORC discussed the recent silting issue and considered applicability to Salem Unit 1. The SORC and engineers determined that the Unit 1 equivalent line, at 12SW536 from the 12 SW accumulator to the 14 and 15 CFCUs, was likely affected. The engineers recalled that the PM activity was deferred during the most recent Unit 1 outage and was not similarly inspected for about 30 months. Control room operators were subsequently notified of the issue and promptly isolated the 12 SW accumulator and declared the 14 and 15 CFCUs inoperable. On May 5, 2005, the SW line at 12SW536 was opened and discovered nearly full of silt. The 12 SW accumulator and 14 and 15 CFCUs were returned to service on May 5, 2005, within Technical Specification allowed outage times.

The inspectors noted that order 30031439 in April 2004 to defer the open and inspect on 12SW536 was actually not recommended by a maintenance manager, no further evaluation or explanation was provided, and the deferral occurred. Exceeding the 18-month frequency was also contrary to the adverse condition noted in notification

20163686 documented in October 2003. Deferring the Unit 1 PM activity outside the April 2004 outage also affected the availability of the 14 and 15 CFCUs. The inspectors observed the as found condition of the 12 SW accumulator silt and concluded that the silt consistency would likely not have rendered the 14 and 15 CFCUs inoperable if the 12 SW accumulator injected. The inspectors' observations were consistent with PSEG's evaluation of the silt.

Analysis. The inspectors determined that PSEG's failure to open and inspect the 12 SW accumulator outlet line in April 2004 at an eighteenth month interval was contrary to known operating experience and established corrective actions and was a performance deficiency. PSEG also did not adequately evaluate a preventive maintenance deferral.

Traditional enforcement does not apply because the issue did not have any actual safety consequence 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 structure, system, or component (SSC) performance attribute of the barrier integrity cornerstone and affected the objective to provide reasonable assurance that containment barriers protect the public from radio nuclide releases caused by accidents or events. The inspectors determined that the finding was of very low safety significance (Green) using Inspection Manual Chapter (IMC) 0609, Appendix H, "Containment Integrity Significance Determination Process," because the CFCUs are not important to large early release frequency, in that, the Salem units have large dry containments and the CFCUs only impact late containment failure and source terms. The performance deficiency associated with the inappropriately deferred preventive maintenance activity had problem identification and resolution (evaluation and corrective action) cross cutting aspects.

Enforcement. 10 CFR 50, Appendix B, Criterion XVI, "Corrective Action," requires that conditions adverse to quality, such as failures, malfunctions, deficiencies, and nonconformances are promptly identified and corrected. Contrary to the above, PSEG did not implement corrective actions to inspect the 12 SW accumulator outlet line at an eighteenth month frequency for silt build-up due in April 2004. The 12 SW accumulator outlet line was inspected in May 2005 and observed to be full of silt. However, because the violation is of very low safety significance (Green) and has been entered into the corrective action program (notification 20237971), this finding is being treated as a non-cited violation consistent with Section VI.A of the NRC Enforcement Policy. **(NCV 05000272/2005003-09, Failure to Properly Inspect Silt Build-up in the 12 SW Accumulator Line)**

2. Technical Support Center Staffing

The inspectors found PSEG's resolution of notification 20232024 adequate and completed in a reasonable time period. The inspectors did not observe any significant TSC staffing deficiencies on June 2, 2005.

3. Low Auxiliary Building Ventilation Flows

The inspectors found the engineering analysis of the air flow discrepancies was thorough. In addition, the inspectors determined that PSEG had appropriately entered the design discrepancy within their corrective action system, and the completed and planned corrective actions appeared reasonable to address the issue.
URI 05000272&311/2005002-02 is closed.

2. Semi-Annual Assessment of Trends

a. Inspection Scope (1 sample)

The inspectors performed a semi-annual review of notifications, condition reports, and control room logs related to repetitive metal impact monitoring system (MIMS) alarms to identify trends that might indicate the existence of a more significant safety issue. The inspectors also interviewed system engineers and operations personnel. MIMS is a detection and alarm system designed to detect loose metal parts in the reactor coolant system that could damage fuel, steam generator tubes, and other internal components. The MIMS detects noises in the reactor coolant system, alerts control room operators, and allows operators to listen to the alarming channel via an audio speaker.

b. Findings and Observations

No findings of significance were identified, however, the inspectors concluded that PSEG did not have a well-defined methodology for tracking and trending MIMS alarms received in the control room. The MIMS often alarmed several times in one day with no detectable noise heard on the audio speaker. This behavior has occurred for a number of years. Although the problem has not been resolved, PSEG is currently troubleshooting the system, including efforts to identify sources of the alarms and options for replacing the aging system. PSEG also increased the rigor to which these alarms are tracked and trended in the control room logs. PSEG determined through troubleshooting efforts that the alarms generated in recent days were due to electronic noise. Because operators did not hear metal impacts on the MIMS audio speaker and troubleshooting efforts identified the cause of recent alarms to be electronic noise, the repetitive MIMS alarms likely did not indicate the presence of loose parts in the reactor coolant system.

3. Safety Conscious Work Environment Review

d. Inspection Scope

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

The inspectors conducted a sampling review of PSEG's SCWE performance indicators (PIs) on May 25 and 26, 2005. During the inspection, a limited number of interviews with PSEG personnel were performed and 30 SCWE performance indicators from the first quarter of 2005 were reviewed.

e. Findings and Observations

No findings of significance were identified.

In the first quarter 2005, PSEG identified 18 PIs as being green (satisfactory) while 12 were identified as red (needs improvement). In comparison to the fourth quarter of 2004, a slightly larger percentage of the indicators reviewed were green, indicating a slight improvement in some areas monitored by the performance indicators. The inspectors noted that the indicators which had shown improvement were mostly associated with equipment reliability. Indicators which were reported as satisfactory during the last quarter of 2004 and needs improvement during the first quarter of 2005 included the number of Employee Concerns complainants requesting anonymity, the corrective maintenance backlog, and the number of Salem Unit 2 Shutdown Limiting Conditions of Operation entered.

The inspectors identified inconsistencies in two of the PIs. First, the inspectors noted that the performance indicator document for the Executive Review Board (ERB) Action Approvals did not indicate how the lapses in the use of the ERB were considered in the calculation for this PI. PSEG personnel stated that the PI did not include those lapses. Secondly, the inspectors noted that the PI for Hope Creek Operational Challenges indicated that the number of challenges increased from 4 challenges in the fourth quarter of 2004, to 5 challenges in the first quarter 2005, but the PI result was Green, "no adverse trend." The inspectors discussed these inconsistencies with PSEG personnel.

Discussion with PSEG personnel and review of the recent survey of the work environment indicated continued uncertainty about how the management changes under the January 17, 2005, Nuclear Operating Services Contract would affect the organizational structure of the site. The performance indicator data reflects this uncertainty, in that the number of requests for anonymity through the Employee Concerns Program (ECP), the number of discrimination complaints through the ECP, and the total number of ECP complaints, increased.

The results of the recent Synergy survey of the status of the work environment indicated an improvement in employees' knowledge of alterative avenues for raising safety concerns. Employee responses regarding employee perception of management commitment, supervisor communication effectiveness, and trust and respect between management and employees remained steady since the last survey in 2003.

4. Lapses in Use of the Executive Review Board Process

a. Inspection Scope

In a June 25, 2004, letter to the NRC, PSEG stated that an ERB had been established to review PSEG and contractor personnel actions to preclude retaliation and/or chilling effect at Salem and Hope Creek. This action was one of a variety of actions taken to generally improve management effectiveness and provide for an improved SCWE at the stations. In addition, in this letter PSEG committed to providing to the NRC, on a quarterly basis, selected performance metrics related to SCWE, which included a metric on ERB effectiveness.

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

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

In a letter dated January 31, 2005, PSEG notified the NRC of its intent to commission an independent review of those personnel actions related to the implementation of the NOSC to ensure that they complied with 10 CFR 50.7, “Employee Protection,” requirements. The NRC acknowledged PSEG’s intention to perform this review in a letter dated February 17, 2005, and requested a written response to specific items. PSEG responded to the NRC in a letter dated March 21, 2005. This item was initially reviewed and documented in NRC Inspection Report 05000272&311/2005002 Section 4OA2.3 and remained open pending further review by NRC staff.

On April 25 through 27, 2005, the NRC performed an inspection into PSEG’s use of the ERB process. The inspectors interviewed selected involved personnel and reviewed the independent review team’s report; PSEG’s March 21, 2005, letter; corrective action program notifications; and other supporting documents. Unresolved Item 50-272&311/2005002-04, Failure to Implement the ERB Process, is closed.

b. Findings and Observations

Introduction. The inspectors identified a Green finding for several lapses in the use of the ERB process. This finding involved not properly implementing a corrective action which had been designed to improve management effectiveness in detecting and preventing retaliation and the creation of a chilling effect. This finding was not a violation of regulatory requirements.

Description. In late December 2004 and early January 2005 PSEG held discussions and reached decisions on personnel actions related to the NOSC that adversely affected a number of PSEG management personnel. These personnel actions were announced on January 7, 2005, without being subject to review by the ERB.

The PSEG senior management who made the personnel decisions based them on business needs and the performance of the affected managers. These senior managers chose not to use the ERB process for a number of reasons, including a belief that an objective ERB review would be difficult because some members of the ERB were affected by the personnel actions, which created an unusual circumstance.

The PSEG-commissioned review team concluded that the decision not to use the ERB process was shortsighted, and that an ERB review could have led to far better communications and execution with respect to the affected managers and the work force. The team noted that PSEG could have pursued the decision from the perspective of trying to make the ERB process work, rather than being hampered by the unusual circumstance discussed above.

The NRC determined that the implementation of the NOSC personnel actions without an ERB review was contrary to company policy. The NRC also noted that some site personnel questioned the non-use of the ERB and expressed concern over the bases of the personnel actions. While the NRC determined that with few exceptions, workers indicated that they would raise issues that they recognized as nuclear safety issues, there was evidence of a range of worker perceptions regarding the advisability of raising issues or challenging issues. The NRC's observations and follow-up actions are discussed in the 'Observations' section below.

The NRC also noted several additional lapses in the use of the ERB, which occurred both before and after the NOSC personnel actions. These instances included:

- A personnel decision for a sub-contracted industrial safety specialist;
- The removal of one individual from Nuclear Duty Officer position and the reassignment of another to the position;
- The unscheduled release of a group of supplemental employees;
- The assignment of a control room supervisor to an "acting" position as shift manager;
- The selection of three employees for participation in the Exelon/PSEG loaned employee program; and
- A vendor's release of an information technology support person.

Analysis. PSEG did not follow company policy for ERB review of several adverse personnel actions. The company policy was used by PSEG to implement corrective actions for SCWE problems, and had been designed to improve management effectiveness in detecting and preventing retaliation and the creation of a chilling effect, as stated in PSEG's June 25, 2004, letter to the NRC. Not following the policy constituted a performance deficiency. 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 if left uncorrected, it would lead to the potential for retaliation and a chilled work environment. This finding was of very low safety significance (Green), based on management review, because there was no direct impact on human performance or equipment reliability. The performance deficiency had a cross cutting aspect in problem identification and resolution (corrective action) because the ERB process was part of the corrective action to improve management effectiveness in detecting and preventing retaliation and the creation of a chilling effect. It also had cross-cutting aspect in the area of SCWE, because the failure to use the ERB process contributed to the range of worker perceptions regarding the advisability of raising issues or challenging decisions.

Enforcement. No violation of regulatory requirements occurred.
(FIN 05000272&311/2005003-10, Failure to Implement the ERB Process)

Observations

The NRC determined that although PSEG had taken corrective actions for some of the early instances of not using the ERB process, these actions were not fully effective because they did not prevent recurrence. This is a problem identification and resolution deficiency that PSEG has placed in the corrective action program.

With regard to the work environment, PSEG concluded that neither the lack of an ERB review of the personnel actions taken nor the personnel actions themselves created a chilling effect where individuals would be reluctant to raise nuclear safety concerns. However, PSEG's review brought forth information about perceptions of workers in the broader context of the work environment such as: some personnel indicated a reluctance to raise questions and/or challenge decisions out of concern that they may appear in some negative light; and some personnel expressed concern about the creation of a chilled environment and PSEG management's adherence to policies and commitments. PSEG attributed these perceptions to uncertainty about the merger, along with ineffective communication about the personnel actions, and in some cases, the decision to not conduct an ERB review of these actions.

The NRC's review determined that with few exceptions workers indicated that they would raise issues that they recognized as nuclear safety issues. However, the NRC also noted evidence of a range of worker perceptions regarding the advisability of raising issues or challenging decisions in the current environment. The NRC determined that these perceptions were related to a collection of factors and were not just attributable to the inconsistent use of the ERB process. These factors included personnel actions that have been taken at the stations, the inconsistent use of the ERB process, uncertainty about the merger, and possibly others. While the NRC recognizes that a range of worker perceptions exists at all facilities, the NRC considers the extent of the perceptions at Salem and Hope Creek to be significant. The NRC's letter to PSEG on January 28, 2004, stated that it is important for PSEG to thoroughly understand what “messages” employees take from experiences at the site and address any situations that can detract from maintenance of a strong SCWE.

In a letter to PSEG dated June 1, 2005, the NRC requested that PSEG re-assess, in the broader context of the work environment, the information emanating from the review of the ERB issue; identify additional actions that have been taken, or planned to take to address worker perceptions; and provide a written response to the NRC within 30 days.

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

Section 1R08.1 describes a finding in which PSEG did not establish adequate corrective actions to preclude repetition of reactor coolant system instrument tubing leaks. This issue had a causal factor in problem identification and resolution (PI&R) corrective action.

Section 1R08.2 describes a finding in which PSEG did not adequately evaluate the structural integrity of a reactor coolant system cold leg weld that was stained with a white substance. This issue had a causal factor in PI&R evaluation.

Section 1R12 describes a finding in which PSEG did not preclude repetition of a charging pump discharge check valve malfunction. This issue had a causal factor in PI&R corrective action.

Section 4OA2.1 describes a finding in which PSEG did not follow through on corrective actions to inspect for silt in a containment fan coil unit service water accumulator outlet pipe. This issue had causal factors in PI&R evaluation and corrective action.

Section 4OA2.4 describes a finding in which PSEG did not follow through on corrective actions to review personnel actions for potential adverse impact on the work environment. This issue had a causal factor in PI&R corrective action.

4OA3 Event Followup (71153 - 6 samples)

1. (Closed) LER 05000272/2005001-00 and Revision 1, Carbon Dioxide Migration Impacts Ability to Perform Safe Shutdown in the Event of a Fire

This LER discussed the preliminary results of an engineering assessment that identified hazardous carbon dioxide concentration levels due to migration from CO2 protected areas. The hazardous levels existed in areas required to be accessible by operators to perform actions in the plant to achieve and maintain safe shutdown in the event of a fire in the vital switchgear rooms. Revision 1 to the LER provided the cause of the carbon dioxide system migration and resolution strategies being assessed by PSEG. The cause of the carbon dioxide system migration was stated as insufficient system design. The resolution strategies being assessed included the use of self contained breathing apparatus to perform manual actions, changes to the post fire safe shutdown procedures, operator training and development of plant modifications. The inspectors verified that PSEG established appropriate compensatory measures in accordance with the Salem Fire Protection Program and as documented in NRC Inspection Report 05000272/2005002 and 05000311/2005002 section 1R05. PSEG disabled the Salem Unit 1 and Unit 2 CO2 suppression systems as an interim measure to alleviate the migration issue from adversely affecting safe shutdown in the event of a fire in the vital switchgear rooms. This LER is closed, but an unresolved item is opened pending inspector review of PSEG's root cause evaluation on timeliness of corrective actions for CO2 migration issues. PSEG's initiated the root cause evaluation in notification 20223951. **(URI 05000272&311/2005003-11, CO2 Migration Impact on Remote Safe Shutdown Operations)**

2. (Closed) LER 05000272/2003005-01, Condition Prohibited by Technical Specifications: Auxiliary Building Ventilation System Fire Damper Found Out of Position

   This LER is Revision 1 to an LER that discussed out of position fire dampers and airflow isolation to emergency core cooling system room exhaust ductwork. Revision 0 was reviewed in NRC Inspection Report 05000272/2004002 and 05000311/2004002. Revision 1 stated that a Safety System Function Failure (SSFF) occurred as defined in NEI 99-02, "Regulatory Assessment Performance Indicator Guideline." The LER further stated that the SSFF determination was previously correctly applied to the NRC performance indicator for SSFF unavailability. This LER is closed.

3. (Closed) LER 05000311/2004006-01, Salem Unit 2 Reactor Trip Due to a Malfunction of a Main Feedwater Regulating Valve (21BF19)

   This LER is Revision 1 to an LER that discussed an automatic reactor trip due to a main feedwater regulating valve malfunction and low 21 steam generator water level. Revision 0 was reviewed in NRC Inspection Report 05000272/2004004 and 05000311/2004004. Revision 1 included the main feedwater regulating valve equipment model number. This LER is closed.

4. (Closed) LER 05000311/2004007-01, Salem Unit 2 Manual Reactor Trip Due to a Malfunction of a Main Feedwater Regulating Valve (23BF19)

   This LER is Revision 1 to an LER that discussed a manual reactor trip in response to a main feedwater regulating valve malfunction and lowering 23 steam generator water level. Revision 0 was reviewed in NRC Inspection Report 05000272/2004004 and 05000311/2004004. Revision 1 included the main feedwater regulating valve equipment model number and expounded on the event root cause. The inspectors reviewed Revision 1 and verified that the root cause was as understood in NRC Inspection Report 05000272/2004004 and 05000311/2004004. This LER is closed.

5. (Closed) LER 05000311/2005001-00, Emergency Core Cooling System (ECCS) Leakage Outside Containment Exceeds Dose Analysis Limits (23 Charging Pump)

   This LER described valve seat leakage from the chemical volume control system to the refueling water storage tank that occurred on March 24, 2005. The leakage rate exceeded the assumptions made in the dose analysis calculation for ECCS leakage outside containment. The inspectors reviewed the LER and associated corrective action evaluation in order 70045982. The inspectors determined that this issue represented a minor performance deficiency, because there was not actual radiological consequence due the valve seat leakage. Further, the administrative leakage limits in the post-accident recirculation path provide defense in depth, by conservatively assuming core damage and to ensure the radiation doses to control room operators would be within 10 CFR 50 General Design Criterion 19 limits. This LER is closed.

6. (Closed) LER 05000311/2004009-00, ECCS Leakage Outside Containment Exceeds Dose Analysis Limits (23 Charging Pump)

This LER described leakage through a manual isolation valve that occurred during a planned maintenance activity. PSEG determined that the leakage rate exceeded the assumptions made in the dose calculation for ECCS leakage outside of containment. The inspectors reviewed the LER and associated corrective action evaluation in order 70042001. The inspectors determined that this issue represented a minor performance deficiency, because there was no actual radiological consequence due to the valve leakage. Further, the administrative leakage limits in the post-accident recirculation path provide defense-in-depth by conservatively assuming core damage and to ensure the radiation doses to control room operators would be within 10 CFR 50 General Design Criterion 19 limits. This LER is closed.

4OA4 Cross Cutting Aspects of Findings

Section 1R04 of this report describes a finding with inadequate procedural adherence that resulted in an inoperable containment fan coil unit. The operators' error had a human performance (personnel) cross cutting aspect.

Section 1R20 of this report describes a finding with inadequate understanding of containment closure procedure requirements. The refuel superintendents' misunderstanding had a human performance (personnel) cross cutting aspect.

Section 4OA2.4 of this report describes a finding in which PSEG did not follow a company policy for Executive Review Board review of several adverse personnel actions. The company policy was used by PSEG to implement corrective actions for safety conscious work environment (SCWE) problems. PSEG's failure to conduct ERB reviews had a SCWE cross cutting aspect.

4OA5 Other

1. Review of Institute of Nuclear Power Operations Evaluation Report

The inspectors reviewed the Institute of Nuclear Power Operations (INPO) final report for an evaluation of the Salem Generating station during the weeks of August 23 and 30, 2004. The report discussed INPO's assessment and PSEG's response.

2. Salem Unit 2 Reactor Vessel Closure Head Replacement Project (71007)

c. Inspection Scope

Recent industry events involving primary water stress corrosion cracking (PWSCC) of alloy 600 material and repairs of the reactor vessel closure heads (RVCHs) at various plants, prompted PSEG to replace the Salem Unit 2 RVCH during the 2R14 refueling outage. The design of the new RVCH is similar to the existing RVCH except for the replacement of the alloy 600 nozzle material and alloy 600 weld material with a new and improved PWSCC resistant material (alloy 690) and other minor improvements.

The replacement RVCH for Salem Unit 2 was made by Japan Steel Works, using a one-piece hemispherical monoblock head forging of SA-508, Grade 3, Class 1 steel and clad with stainless steel on the inside. It was machined and fabricated by Framatome, ANP in the Chalon-St. Marcel, France facility. The head was fabricated with 57 control rod drive mechanism (CRDM) alloy 690 penetration pressure housing assemblies that were shrunk fit into the RVCH and attached with alloy 152/52 filler material partial penetration J-groove welds. The RVCH includes a reactor vessel head vent (RVHV) nozzle and a reactor vessel level indication system (RVLIS) nozzle constructed from alloy 690 material. The RVCH does not have any core exit thermocouple penetrations. The completed RVCH assembly was hydrostatically pressure tested at Framatome ANP, Inc. facilities in France prior to being transported to Salem Unit 2 for installation. In addition, a new integrated head assembly (IHA) and new CRDMs were designed and procured for the replacement RVCH. PSEG determined that the CRDMs would be transferred from the old Salem Unit 2 RVCH to the Salem Unit 1 RVCH replacement during the next refueling outage, to be used for future operation on Unit 1.

Design and Planning

The inspectors reviewed the Salem Unit 2 RVCH replacement project using the guidance in NRC Inspection Procedure 71007, “Reactor Vessel Head Replacement Inspection.”

The inspectors verified that PSEG reviewed and documented the RVCH related design changes and modifications to components described in the UFSAR in accordance with 10 CFR 50.59. The inspectors also reviewed the adequacy of 10 CFR 50.59 applicability reviews, screening evaluations, or safety evaluations for design changes, modifications, and procedure changes. To verify that design activities for the Salem Unit 2 replacement RVCH, IHA, and CRDMs were performed in accordance with 10CFR 50.59 requirements, the inspectors reviewed applicable design documents related to the components being replaced and compared the changes to the original RVCH that was designed in accordance with design and fabrication specifications PSBP 326408 (Westinghouse E-Spec 676413) and ASME Boiler and Pressure Vessel (B&PV) Code, and Section III, 1965 Edition through 1966 Winter Addenda requirements.

The inspectors reviewed AREVA engineering information record 51-5044537-01, Salem Unit 2 Reactor Vessel Closure Head Code Reconciliation report which reconciles the requirements of the current code of construction and current owner's requirements to the original owner's requirements and the requirements of the original code of construction.

The inspectors conducted in-office and onsite reviews of design change packages, engineering calculations, analyses, design specifications, material specifications, piping specifications, equipment specifications, installation specifications, certified design reports, and various drawings for the Salem Unit 2 replacement RVCH, IHA, and CRDMs to assess the technical adequacy of the design changes and to verify that the design bases, licensing bases, and the performance capability of the modified components were not degraded through the modifications.

The design and fabrication of the replacement RVCH, IHA, and CRDMs were specified by PSEG in certified design specifications. Framatome performed the analyses, calculations or evaluations necessary to support the 10 CFR 50.59 evaluations of the replacement RVCH, IHA, and CRDMs. The design changes for the replacement components were documented through PSEG's design change package process in accordance with NC.CC.AP.ZZ-0080 (Q). The design change packages for the RVCH, IHA, and CRDMs included:

- Evaluations and/or analyses to show that all applicable acceptance criteria were met with the replacement RVCH, IHA, and CRDMs; and
- Reviews of the plant Technical Specifications, UFSAR, SERs, and emergency operating procedures to identify changes required by use of the replacement RVCH, IHA, and CRDMs.

The replacement CRDM pressure housing assemblies were designed in accordance with Salem Design Specification S-2-RC-MDS-0408. The ASME Certified Design Reports (PSBP 326576, PSBP 326615 and PSBP 326616) were also reviewed by the inspectors to confirm that the requirements of the design specification were met.

The existing seismic support and CRDM ventilation equipment were replaced with an IHA that was designed by Advent Engineering Services, Inc and documented in DCP 80057549, which the inspectors reviewed.

The replacement components design was reviewed to the ASME B&PV Code Section III and Section XI, 1998 Edition through 2000 Addenda, applicable sections of the Salem Unit 2 UFSAR, material specifications, original Westinghouse Design Specification E-Spec 676413, replacement design specification S-C-RC-NGS-0177 Replacement Reactor Vessel Closure Heads for Salem Units 1 and 2, and certified design report Framatome FANP 33-5044672, ASME Design Report For Salem Unit 1 & 2 Replacement RV Closure Head requirements.

The inspectors also reviewed Framatome Engineering Information Record 51-5030154-00, Photogrammetry Measurements of the Reactor Vessel & Head at Salem Unit 2. This document provided the results of the photogrammetric surveys and analysis of the Salem Unit 2 reactor vessel and RVCH. Based on the data collected, the photogrammetry information was reconciled to the design dimensions and no changes were required to the replacement RVCH. The inspectors confirmed that the replacement RVCH conformed to design drawings and there were no fabrication deviations from design.

The inspectors reviewed ALARA planning and job dose estimates and dose tracking as it related to the vessel head replacement. The inspectors reviewed outage exposure goals as they related to the Unit 2 reactor vessel head replacement, and attended a station ALARA committee meeting on April 19, 2005, held to discuss outage exposures to date, and the effect of emergent vessel head work had and was projected to have on the outage exposure goals.

RVCH Replacement Lifting/Rigging and Transportation Activities

The adequacy of the lifting and rigging activities were evaluated and/or tested to verify that the maximum anticipated loads to be lifted would not exceed the capacity of the lifting/rigging equipment and supporting structures. The inspectors reviewed the analysis of the potential impact of load handling activities on the reactor core, spent fuel cooling, and other plant support systems and the consequence of any impact loading of structures, systems, and components due to a RVCH drop accident.

The inspectors reviewed DCP 80056406, “Restoration of 230 Ton Polar Crane Capacity” and Whiting Corporations’ certification letter dated June 9, 2004, reconciling Whiting Corporations’ 1994, 10 CFR Part 21 issue. The maximum rated capacity of the Salem Unit 2 Polar crane, which is not single failure proof, has been restored to its full (original design) load capacity of 230 tons by replacing 30 existing bolts located on the sheave nest side plates of the polar crane with 30 (A325) high strength bolts.

The existing Salem Unit 2 tripod lifting eye was used because the procured replacement tripod lift eyes for both Salem Units were found to be unacceptable since they developed cracks during the machining process. Advent Engineering Services, Inc. performed a structural analysis documented in Technical Report 03026TR-11, “Integrated Head Assembly Design Reconciliation of Existing Salem Lift Eye,” Revision 1, to reconcile using the existing Salem Unit 2 tripod lifting eye.

The inspectors reviewed the adequacy of the transport programs and procedures to assure that they were prepared and evaluated in accordance with applicable design requirements, appropriate industrial codes, standards and regulatory requirements. Specifically, the review included PSEG’s evaluation and analyses of underground buried commodities for the transport path of the old and replacement RVCHs. The onsite haul path segments were from the Salem Unit 2 North equipment hatch to the Hope Creek Turbine Building and from there West of Hope Creek to the proposed storage/laydown area and finally to the Salem barge slip. The seismic category 1 station service water system intake piping buried beneath the RVCHs heavy haul load path as documented in Design Change Package 80072727, “Site-Wide Heavy Haul Path”, was reviewed to ensure that the piping would not be damaged. The under ground commodities along the heavy haul path segments were determined to be adequate to accommodate the bearing transporter loads with certain compensatory measures being implemented during the RVCHs movement. These measures included placing temporary steel plating over some commodities on segments of the heavy haul path and providing cribbing in the storage/laydown area in order to distribute the RVCH load.

Reactor Vessel Head Fabrication Inspections

The inspectors performed reviews of design specification S-C-RC-NGS-0177 and PSBP 327343 for the Salem Unit 2 replacement RVCH to verify that the material, design, fabrication, inspection, examination, testing, certification, documentation, and functional requirements specified were consistent with the requirements of the ASME Boiler and Pressure Vessel Code, Section III, Division I, 1998 Edition, through 2000 Addenda.

The inspectors reviewed Salem Unit 2 RVCH Code Reconciliation report (51-5044537-01), the ASME Code Data Report Form - 2 and the End of Manufacturing Reports (EMRs) for the Salem Unit 2 replacement RVCH assembly. The reconciliation report addressed the specified design, materials, fabrication, and examination of the replacement RVCH. The EMRs contained certified material test reports (CMTR), heat treatment records, weld records, non-conformance reports, corrective actions, non-destructive evaluations, and weld material acceptance tests for the manufacture of the replacement RVCH and CRDMs. The inspectors verified that the authorized nuclear inspectors (ANI) at the Framatome, ANP Chalon/Saint Marcel facilities had inspected the replacement parts, reviewed the manufacturing reports, and certified that the fabricated components were in accordance with the ASME Code, Section III, Division 1.

The inspectors observed the implementation of Framatome ANP manufacturing specification procedure 6 MN 11709, "Thin Edge Welding of Components on the Reactor Closure Head Adapters - Automatic TIG Orbital Process - Welding Machine Type PROTIG 315," Revision L. The inspectors performed field observations of a sample of in-process TIG canopy seal welding activities by Framatome technicians of CRDM latch housings to adapter assemblies CRDM #'s 2703, 2706, 2710, and 2711 inside the Hope Creek Turbine Building via remote video monitor. Particular attention was devoted to the verifications performed during TIG welding operations, parameter recording verifications, and examinations performed after the welding.

The inspectors reviewed the following as it related to the vessel head replacement: exposure controls, including temporary shielding; airborne and contamination controls; radioactive material controls and management; radiological work plans and controls; emergency contingencies; project staffing and training plans; and, evaluation of radiological source term, including presence of hard-to-detect radionuclides, including transuranics.

Pre-service Inspection (PSI) and Baseline Inspections of Replacement RVCH

The inspectors reviewed the Salem Unit 2 RVCH Replacement Baseline NDE Final Report, AREVA Engineering Information Record (EIR) 51-5061492-00 and EIR 51-5061112-00, which documented the NDE performed to satisfy the requirements in PSEG purchase order 035076205 and PSEG design specification S-C-RC-NGS-0177 Salem Unit 2 Replacement RVCH. The report provides baseline examination data for future in-service inspections for CRDM, vent line, RVLIS line and dissimilar metal (DM) examinations, and serves as a PSI in accordance with ASME Boiler & Pressure Vessel Code Sections III & XI 1998 through 2000 Addenda requirements for DM welds and to meet the First Revision to NRC Order EA-03-009.

The intent of baseline examinations was to provide guidance for future examination efforts pertaining to pre-existing fabrication indications and there locations. The baseline inspections consisted of: (1) automated inside diameter UT and eddy current (ET) examination of 57 CRDM penetrations, RVLIS line penetration, and reactor head vent line penetration (2) outside diameter and J-groove weld eddy current (ET) examination of 57 CRDM penetrations, RVLIS penetration and the vent line penetration, (3) under head visual test (VT) examination of all J-groove welds and penetration outside diameters, (4) top of head bare metal VT examination of all penetrations, and (5) under head PT examination of all penetration to head J-groove welds using “PT White” acceptance criteria. For these examinations, the inspectors reviewed the Reactor Vessel Head Penetration NDE Inspection Final Report For PSEG Salem Unit 2 (Baseline) results, a sample of PT records for the J-groove welds, a sample of the automated UT results, and reviewed video tape and digital photographic records of a sample J-groove welds following completion of the liquid penetrant examinations.

During baseline volumetric UT examinations performed after the hydrostatic pressure test at the Framatome ANP facility in Chalon/Saint Marcel, France of the 57 CRDM pressure housing penetration J-groove welds using Time of Flight Diffraction (TOFD) ultrasonic units, a total of 585 fabrication indications believed to be slag inclusions were detected within the J-groove welds and recorded on CRDM UT examination report data sheets. The data sheets document the locations and depths of the fabrication indications. The worst case CRDM penetration #67 had 22 separate indications and CRDM penetration #1 had a single fabrication indication of length 2.3" circumferentially around the J-groove weld. PSEG contracted Structural Integrity Associates, Inc. (SIA) to evaluate the potential effects on the structural integrity and future performance of the RVCH. The SIA evaluation concluded that all regions of the reactor head and nozzles remain well within applicable ASME B&PV Code, Section III limits. Based on the SIA evaluation the Salem Unit 2 RVCH is structurally adequate for service.

Removal and Replacement of RVCHs

The inspectors verified that no major structural modifications were performed for the RVCH replacement activity. The inspectors verified that no temporary modifications were needed for containment access to support the RVCH replacement activity.

The inspectors reviewed activities associated with removal and replacement of the RVCHs. The review focused on applicable lifting and handling procedures. The inspectors reviewed the procedures for heavy lifting and for inspection and testing of the cranes and lifting equipment. The inspectors verified that the capability of the lifting equipment had been inspected, tested, and/or evaluated though engineering calculations and analyses.

The inspectors reviewed selected applicable portions of the preparation for moving the old RVCH out of containment and to the Hope Creek Turbine Building in order to remove the old CRDMs for use on the Salem Unit 1 RVCH replacement during the Fall 2005 1R17 refueling outage.

The inspectors observed portions of the movement of the old RVCH from the Salem Unit 2 containment. While attempting to rig out the old RVCH with CRDMs attached from the containment a temporary CRDM upend/downend system support (cheese plate), on the rigging equipment used to support the CRDMs buckled during horizontal movement activities just inside the equipment hatch of the containment. Action was taken to stabilize the old RVCH and implement a recovery plan that safely removed the old RVCH from the containment. Modifications to strengthen the cheese plate were implemented and FANP condition report CR 2005-1512 was prepared to determine the root cause of the cheese plate failure and perform an evaluation of the CRDMs on the old RVCH to determine if they were damaged. PSEG also issued Notification 20233810 to document and evaluate the issue. There were no industrial safety injuries or radiological concerns as a result of event. The event delayed RVCH replacement activities and potentially damaged some of the CRDMs that are to be installed in the Salem Unit 1 replacement RVCH. The inspectors observed some of the recovery actions and reviewed the AREVA root cause report FANP-05-1970 for the support plate failure. The direct cause was that the cheese plate was over stressed when loaded to support the reactor head at an interim position during down ending to modify the rigging and buckled during subsequent horizontal movement out of containment.

Post-Installation Verification and Testing

The inspectors verified that the PMT of the installed component replacements RVCH, IHA, and CRDMs cooling system and rod control system were conducted in accordance with approved procedures and verified that the functional testing confirmed the design and established some baseline measurements. Specifically, the procedures reviewed were S2.IC-ST.RCS-0003, "Rod Control System and IRPI Integrated Test at Hot Zero Power," and S2.IC-PT.RCS-0008, "S2 CRDM's-REM Fuses & Cable Checks."

No RCS leakage was observed from the replacement RVCH during containment Class 1 walkdowns conducted by certified VT-2 Level 2 examiners and documented on PSEG visual examination VT-2 data sheets.

Quality Assurance (QA) Oversight

The inspectors reviewed PSEG QA oversight of contractor activities for the RVCH replacement by direct field observation and reviewing QA audits and surveillances performed by PSEG QA personnel of shop work activities at the Framatome, ANP facilities in Chalon-St. Marcel, France and Jeumont, France. The inspectors reviewed a sample of audit concerns and non-conformance reports pertaining to the RVCH and CRDMs. The inspectors reviewed the following PSEG QA audits and followup corrective actions to resolve the audit concerns. PSEG QA Audit NQA 04 -147 which identified quality concerns at the Framatome ANP Chalon St. Marcel, France Plant and PSEG QA

Audit NQA 04-0033. In addition, the inspectors discussed several of the quality assurance audit and surveillance concerns of the RVCH and CRDMs with members of PSEG QA and Salem Unit 2 replacement RVCH project personnel.

b. Findings

No findings of significance were identified.

2. Temporary Instruction 2515/163, Operational Readiness of Offsite Power

The inspector performed Temporary Instruction 2515/163, “Operational Readiness of Offsite Power.” The inspector collected and reviewed licensee procedures and supporting information pertaining to the offsite power system specifically relating to the areas of offsite power operability, the maintenance rule (10 CFR 50.65), and the station blackout rule (10 CFR 50.63). The inspector reviewed this data against the requirements of 10 CFR 50.63; 10 CFR 50.65; 10 CFR 50 Appendix A General Design Criterion 17, “Electric Power Systems;” and Salem Technical Specifications. This information was forwarded to NRR for further review.

3. TI 2515/152 - Reactor Pressure Vessel (RPV) Lower Head Penetration (LHP) Nozzles (NRC BULLETIN 2003-02)

a. Inspection Scope

The inspectors reviewed PSEG’s response to NRC Bulletin 2003-02 which described the RPV lower head penetration inspection program. The inspectors reviewed the LHP nozzle examination procedure to determine whether it provided adequate guidance and examination criteria to implement PSEG’s examination plan. The inspectors reviewed examination personnel training and qualification records to ensure that personnel were adequately prepared to perform the assigned examination activities.

The inspectors observed selected LHP inspection activities and also reviewed photographs and examination reports to determine whether the inspection procedure was effectively implemented. The inspectors observed the review of several penetration nozzles to evaluate the effectiveness of the visual (VT) examination to verify that the penetration intersection location could be fully accessed to perform a 360-degree examination. The inspectors reviewed the disposition and actions for observations related to the minor oxidation, and dried boron that was present on some penetrations on the lower head.

b. Findings

No findings of significance were identified.

The following input addresses the specific reporting requirements of TI 2515/152:

a.1. The examination was performed by qualified and knowledgeable personnel with certification to the ASME, Section XI, Level II and Level III for visual examiners. In addition, Level II and Level III examiners had received a minimum period of training in this type of inspection. The training included a review of the penetration drawings, inspection techniques and use of visual aids, effects of surface conditions on detecting and evaluating indications, industry experience, lessons learned, inspection results and procedure requirements.

a.2. The examination was performed using an adequate procedure which provided clear standards and acceptance criteria for the inspection observations.

a.3. The examination was adequate to identify, resolve, and disposition deficiencies.

a.4. The examination performed was capable of identifying active pressure boundary leakage and/or lower head corrosion as described in the bulletin.

b. The inspection was conducted by direct visual inspection by examination personnel. The inspection effort achieved examination for 360 degrees around the circumference of all nozzles. No video or photographic record was made of the general condition of the lower head or the BMI penetration nozzles.

c. If present, small, active boric acid deposits representing reactor coolant leakage, as described in Bulletin 2003-02, could be identified and characterized.

d. Notification 20232316 documents the existence of some minor dimples in the coating material on the lower reactor vessel head. No indications were identified at the time this inspection was performed with the BMI tubes or the reactor vessel lower head. The reactor vessel lower head contained some minor debris and dried boron residue. No active boric acid deposits or leaks were identified at the interface between the vessel and the lower reactor head penetrations.

e. This was the second inspection performed at Salem Unit 2 subsequent to issuance of Bulletin 2003-02, and full access to the lower head was provided. The licensee removed all insulation from the lower reactor vessel head.

f. No active boric acid leak deposits were noted on the lower vessel head. Some stains, attributed to prior reactor cavity seal leakage, were observed at a few locations. These indications were evaluated by the licensee as not pressure boundary leakage.

g. No locations were sampled for dried boron deposits because no evidence of leakage was observed.

h. Cleaning of selected penetrations intersecting the lower vessel head was not required.

l. The licensee noted and recorded minor conditions or indications on the VT data sheets.

4OA6 Meetings, Including Exit

NRC/PSEG Management Meeting - Reactor Oversight Process Annual Assessment. The NRC conducted a meeting with PSEG on June 8, 2005, to discuss (1) NRC's annual assessment of safety performance at Salem and Hope Creek for calendar year 2004, and (2) PSEG actions to improve performance in safety conscious work environment, problem identification and resolution, procedure adherence and other elements of human performance, and quality of engineering products. The meeting occurred at the Holiday Inn Select Bridgeport, New Jersey and was open for public observation. A copy of slide presentations and other background documents can be found in ADAMS under accession number ML050750455.

Executive Director of Operations Site Visit. On June 9, 2005, a site visit was conducted by Mr. Luis Reyes, Executive Director of Operations for the NRC. Mr. Reyes was accompanied by Mr. Samuel Collins, Regional Administrator. During Mr. Reyes' visit, he toured the Salem and Hope Creek plants and met with PSEG managers.

Exit Meeting. On June 30, 2005, the resident inspectors presented the inspection results to Mr. Tom Joyce and other members of his staff who acknowledged the findings. The inspectors confirmed that proprietary information was not provided or examined during the inspection.

4OA7 Licensee-Identified Violations

The following violations of very low significance (Green) were identified by PSEG and are violations of NRC requirements which meet the criteria of Section VI of the NRC Enforcement Policy, NUREG-1600, for being dispositioned as a NCVs.

C Salem Unit 2 Technical Specification 6.12.1 requires that areas having dose rates in excess of 100 millirem per hour measured 30 centimeters from the source of radiation be posted, barricaded and access controlled as a high radiation area. Each individual or group entering the area shall possess a radiation monitoring device that alarms when the device's dose alarm setpoint is reached. Contrary to this requirement, on April 18, 2005, a PSEG radiation protection technician identified that a worker in the Unit 2 containment, a posted high radiation area with dose rates in excess of 100 millirem per hour measured 30 centimeters from the source of radiation, had an electronic dosimeter that was in alarm, having exceeded its pre-set alarm dose setpoint. The worker was unaware of the alarm, as the work area included high noise levels. The worker did not utilize specially designed electronic dosimeters made available by PSEG for work in high noise areas, nor had the worker periodically checked his dose measured by the electronic dosimeter as instructed to by radiation protection technicians during his pre-job briefing. This finding is of very low safety significance because it did not involve a locked high or very high radiation area or personnel over-exposure. PSEG this issue in notification 20234154.

C 10 CFR 50, Appendix B, Criterion XVI, “Corrective Action” requires that measures shall be established to assure that conditions adverse to quality, such as failures, malfunctions, defective material and equipment, and nonconformances are promptly identified and corrected. Contrary to this requirement, the Unit 2 ECCS containment sump was visually inspected for deficiencies in November 2003 but some bypass flow areas at the 1/8 inch mesh screen were not identified until April 2005. The bypass flow areas were determined not to have rendered the ECCS sump inoperable as documented in PSEG evaluation 70047482. In accordance with IMC 0609, Appendix A, “Significance Determination of Reactor Inspection Findings for At-Power Situations,” the inspectors conducted a Phase 1 SDP Screening and determined the finding to be of very low safety significance (Green). This finding screened to Green because the finding was not a design or qualification deficiency, did not represent a loss of system safety function, did not represent an actual loss of safety function of a single train for greater than its TS allowed outage time, and did not screen as potentially risk significant due to external events. PSEG documented this deficiency in notification 20238016.

ATTACHMENT: SUPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee personnel:
D. Burgin, EP Manager
H. Berrick, Licensing
J. D'Souza, REMP Coordinator
R. Farrington, Senior Test Engineer, Maplewood Laboratory
C. Fricker, Plant Manager
G. Gardner, System Engineer
T. Gierich, Operations Manager
R. Gary, Technical Superintendent - Radiation Protection
T. Joyce, Salem Vice President
D. Karpiej, Senior Test Engineer, Maplewood Laboratory
D. Labott, Project Manager, Reactor Head Replacement
J. Roberts, Supervisor, Engineering Programs
T. Roberts, Materials Manager
G. Sosson, System Engineering Manager
J. Stone, Maintenance Manager
J. Sullivan, Assistant Operation Manager
W. Treston, PSEG ISI Manager
S. Zeigler, Nuclear Technical Specialist - ALARA

LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

05000311/2005003-03	URI	Assessment of Reactor Coolant System Instrument Tube Structural Integrity (Section 1R08.2)
05000311/2005003-05	URI	Containment Closure (Section 1R13)
05000272&311/2005003-11	URI	CO2 Migration Impact on Remote Safe Shutdown Operations (Section 4OA3.1)

Opened/Closed

05000272/2005003-01	NCV	15 Containment Fan Coil Unit Inoperable Due to Configuration Control Error (Section 1R04)
05000311/2005003-02	NCV	Through-wall Leakage in Reactor Coolant System Instrument Tubing (Section 1R08.1)

05000311/2005003-04	NCV	Unavailability of 22 Charging Pump due to Discharge Check Valve Leakage (Section 1R12.1)
05000311/2005003-06	NCV	Reactor Sump Room Door Design Deficiency (Section 1R15)
05000311/2005003-07	NCV	Containment Closure Requirements Not Satisfied (Section 1R20)
05000272&311/2005003-08	NCV	Inadequate 10 CFR 50.54(t) Audit (Section 1EP5)
05000272/2005003-09	NCV	Failure to Properly Inspect Silt Build-up in the 12 SW Accumulator Line (Section 4OA2)
05000272&311/2005003-10	FIN	Failure to Implement the ERB Process (Section 4OA2.4)
05000272/2005001-00 and Revision 1	LER	Carbon Dioxide Migration Impacts Ability to Perform Safe Shutdown in the Event of a Fire (Section 4OA3.1)
05000272/2003005-01	LER	Condition Prohibited by Technical Specifications: Auxiliary Building Ventilation System Fire Damper Found Out of Position (Section 4OA3.2)
05000311/2004006-01	LER	Salem Unit 2 Reactor Trip Due to a Malfunction of a Main Feedwater Regulating Valve (21BF19) (Section 4OA3.3)
05000311/2004007-01	LER	Salem Unit 2 Manual Reactor Trip Due to a Malfunction of a Main Feedwater Regulating Valve (23BF19) (Section 4OA3.4)
05000311/2005001-00	LER	ECCS Leakage Outside Containment Exceeds Dose Analysis Limits (23 Charging Pump) (Section 4OA3.5)
05000311/2004009-00	LER	ECCS Leakage Outside Containment Exceeds Dose Analysis Limits (23 Charging Pump) (Section 4OA3.6)

Closed

05000272&311/2004007-02	URI	Salem Simulator Fidelity Concern Regarding Containment Level Response to Flooding (Section (1R15)

05000272&311/2005002-02	URI	Low Auxiliary Building Ventilation Flows (Section 4OA2)
05000272&311/2005002-04	URI	Failure to Implement the ERB Process (Section 4OA2.4)

LIST OF DOCUMENTS REVIEWED

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

Section 1R01: Adverse Weather Protection

Procedures

NC.OP-DG.ZZ-0002, Severe Weather Guide
SH.OP-DG.ZZ-0011, Station Seasonal Readiness Guide
SC.OP-PT.ZZ-0002, Station Preparations for Seasonal Conditions
SC.OP-AB.ZZ-0001, Adverse Environmental Conditions

Notifications

20235172, 20221277

Orders

70047089, 80028239

Other Documents

Letter dated 15 May 2005 to Carl Fricker from Seasonal Readiness Team, re: Salem Station Summer Readiness
Salem Summer Readiness Preparation Status - 2005
CROD 05-006 (20228644/70045529) concerning control area ventilation switchgear outside air intake dampers
CROD 05-004 (70045063) concerning auxiliary building ventilation
CROD 04-024 (20209163/70041840) concerning service water valve 39 for all six emergency diesel generators
System Health Report, Salem 1, Service Water System
System Health Report, Salem 2, Service Water System

Section 1R04: Equipment Alignment

Procedures

S2.OP-SO.SW-0003, 22 Nuclear Service Water Header Outage
S2.OP-AB.FUEL-0002, Loss of Refueling Cavity or Spent Fuel Pool Level
S2.OP-SO.SF-0006, Spent Fuel Pool Emergency Fill
SC.OP-PT.SF-0001, Portable Spent Fuel Pit Pump Operability Test
SC.OP-PT.SF-0002, Portable Spent Fuel Pit Pump Full Flow Test
S2.OP-SO.SF-0002, Spent Fuel Cooling System Operation
S2.OP-SO.RHR-0001, Initiating RHR
S2.OP-SO.RHR-0002, Terminating RHR

Drawings

205342

Orders

20235749, 20235831

Other Documents

Tagging Work List 4152072, 22 CC Hx Outage (disabled valves) 2R14.
Calculation S-C-SF-MDC-1800, Decay Heat-up Rates and Curves

Section 1R05: Fire Protection

Notifications

20237652, 20238252, 20238239, 20238251, 20238429, 20238430, 20238573, 20234580, 20233122, 20239536, 20233122, 20234580, 20239536, 20237652

Other Documents

Salem Pre-Fire Plans:
FRS-II-611, Unit 2 Containment
FRS-II-433, Unit 1 and Unit 2 Auxiliary Feed Water Pumps Area
FRS-II-434, Unit 1 and Unit 2 Charging Pump, Spray Additive Tank Area
FRS-II-435, Unit 1 and Unit 2 Diesel Fuel Oil Storage Area
FRS-II-445, Unit 1 and Unit 2 Diesel Generator Area

Section 1R06: Flood Protection Measures

Notifications

20239966, 20240101, 20239978, 20237652

Other Documents

Salem Generating Station Individual Plant Examination
Calculation 6S0-1808 (Determination of Water Tight Door Classification)

Section 1R07: Heat Sink Performance

Procedures

S2.OP-PT.SW-0026, 21 Component Cooling Heat Exchanger Heat Transfer Performance Data Collection

Other Documents

Calculation S-C-CC-MDC-1798, Component Cooling System Heat Exchangers.

Section 1R08: Inservice Inspection Activities

Procedures

SH.RA-IS.ZZ-0119, Liquid Penetrant Evaluation Solvent Removable Or Water Washable
S2-OP-ST.CVC-0010, Borated Water Sources
SH.RA-IS.ZZ-0116, Visual Examination of Nuclear Class I Bolting, Nuclear Class 3 Integral Welded Attachments, Nuclear Class I Pump/Valve Internal Surfaces, Nuclear Class I External Pump Casing Weld Surfaces
SH.RA-IS.ZZ-0150, Nuclear Class 1,2,3 and MC Component Support Visual Examination
SH.RA-IS.ZZ-0003, VT-3 Visual Bolting Examination
SH.RA-IS.ZZ-0005, VT-2 Visual Examination of Nuclear Class 1, 2 and 3 Systems
SH.RA-IS.ZZ-8805, Boric Acid Corrosion Visual Examinations
SH.RA-AP.ZZ-8805, Boric Acid Corrosion Management Program
NC.RA-DG.ZZ-8805, Boric Acid Corrosion Management Program Corrective Action Process Guidelines
NC.RA-TS.ZZ-8805, Boric Acid Corrosion Evaluations
SH.RA. IS.ZZ-0117, Dry Powder and Fluorescent Magnetic Particle Examination
SH.RA-IS.ZZ-0139, Recording Data From Direct Visual Liquid Penetrant And Magnetic Particle Examinations
SH.RA-IS.RC-0001, Vessel Head Penetration Examination
SH.RA. SP.ZZ-0217, Radiographic Examination of Welds
VSH.RA. SP.ZZ-0210, Radiographic Examination Of Welds ANSI B31.7

Notifications

20233744, 20233745, 20201310, 20171114, 20215370, 20199067, 20166164, 20181074, 20216827, 20161764, 20235848, 20237162, 20237161, 20237296, 20236889, 20234950, 20234499, 20233747, 20232316, 20234737, 20235186, 20235035, 20192451, 20191367, 20199067, 20162315, 20165517, 20171191, 20190617, 20191367, 20204533, 20166167, 20166168, 20214123, 20229597, 20174270, 20237109, 20236740, 20237164, 20237293, 20236890, 20235051, 20233095, 20233745, 20239528, 20234455, 20154232, 20161764, 20162315, 20165517, 20171191, 20185605, 20187497, 20188032, 20192451, 20211965, 20163455, 20166165, 20176147, 20214207, 20229573, 20183500, 20236737, 20237255, 20237373, 20237295, 20236149, 20234949, 20235848, 20235402, 20236890, 20174270, 20183500, 20185605, 20187497, 20190617, 20204533, 20233422, 20234149, 20233736, 20233735, 20216827, 20229597, 20229573, 20211965, 20233368, 20234150, 20166168, 20163455, 20166165, 20166167, 20166164, 20176147, 20181074, 20214123, 20234147

Notifications for Deviation Memo Sample

20203255, 20212120, 20219275, 20231420, 20214253, 20163247, 20171960, 20183733, 20183771, 20183709, 20184831, 20188231, 20188505, 20192655, 20201942, 20214169

Evaluation Orders

70045063, 70040391, 7008537, 20226355

NDE Examination Reports

007115, U2 RPV Lower Head BMI Penetrations & Flux Thimble Tube Dissimilar Metal Welds (VT)
060000, Pressurizer Surge Line: Nozzle to Safe End (UT)
011500, 6-PRN-1205-IRS, (UT)
011800, 6-PR-1205-1, (UT)
020300, 22-STG-LHTS, (UT)
055850, 3-PR-1207-13, (PT)
057000, 3-PR-1206-13, (PT)
174450, 6-RH-1231-19, (UT)
255050, 2CV2 Bolting, (VT-1, VT-2)
055200, 2CV275 Bolting, (VT-1, VT-2)
275040, 2-CVCT-2VS-(1-8)IA, (PT)
350099, 8-CS-2225-25, (PT)
381030, 32-MS-2241-1PS-3 Thru 12, (MT)
382220, 8-MS-2245-3, (MT)
S2RC-81-5; 4", Schedule 160, RCS Fill & Drain Vent (RT)
S2RC-98-1, 4", Schedule 160, RCS Fill & Drain Vent (RT)
S2RC-81-6, 4", Schedule 160, RCS Fill & Drain Vent (RT)
S2-2-SGF24-FW1, 14", Schedule 80, FW Piping (RT)
S2-2-SGF52-1, 14", Schedule 80, FW Piping (RT)
384020, 8-MS-2212-3, (MT)

Other Documents

S-2-RC-MEE-1892, 2R14 Steam Generator Degradation Assessment
VTD 326355, PSE-03-54, 11/3/03; PSEG Nuclear Salem U2 Disposition of Boron Crusted PIP's
BACM Program On-Line Monitoring 2004, 9/14/04
Salem U1 & U2 4th Quarter 2004, BACM Program Collective Analysis RCS Identified & Unidentified Leakage Rates, 12/28/04
On-Going Self - Assessment Report (BACM Self-Assessment), 6/14/04
Boric Acid Corrosion Management Program Engineering Self-Assessment Results, NC.ER-DG.ZZ-0005(Z), Revision 0.
Boric Acid Corrosion Management Program Health Report; June to December 2004
Areva Document 51-5064071-00, 4/30/05; Salem 2 22 SG Outlet Nozzle Deposit Sample Analysis
PSEG Ltr. LR-N04-0322, 7/27/04; 60-Day Response to Bulletin 2004-01, Inspection of alloy 2/182/600 Materials Used in Fabrication of Pressurizer Penetrations and Steam Space Piping Connections at Pressurized-Water Reactors, Salem Generating Station Units 1 and 2, Docket Nos. 50-272 and 50-311, Facility Operating License Nos. DPR-70 and DPR-75
NRC Ltr. Dated 4/15/94, Evaluation of Supplemental Response to NRC Bulletin No. 88-09, Thimble Tube Thinning In Westinghouse Reactors, Salem Nuclear Generating Stations Unit 1 and 2 (TAC Nos. M88472 and M88473)

Section 1R11: Licensed Operator Requalification

Procedures

NC.NA-AP.ZZ-0005, Station Operating Practices
S2.OP-AB.CAV-0001, Loss of Unit 2 Control Area HVAC
S2.OP-AB.LOAD-0001, Rapid Load Reduction
2-EOP-TRIP-1, Reactor Trip or Safety Injection
2-EOP-FRCE-1, Response to Excessive Containment Pressure
2-EOP-LOCA-1, Loss of Reactor Coolant
2-EOP-LOCA-5, Loss of Emergency Recirculation

Other Documents

Simulator Training Scenario SG-0521 (Normal Plant Ops and LOCA-5)
Salem Event Classification Guide (ECG)

Section 1R13: Maintenance Risk Assessments and Emergent Work Evaluation

Procedures

S2.OP-AB.FUEL-0002, Loss of Refueling Cavity or Spent Fuel Pool Level
S2.OP-SO.SF-0006, Spent Fuel Pool Emergency Fill
SC.OP-PT.SF-0001, Portable Spent Fuel Pit Pump Operability Test

SC.OP-PT.SF-0002, Portable Spent Fuel Pit Pump Full Flow Test
S2.OP-SO.SF-0002, Spent Fuel Cooling System Operation
S2.OP-SO.RC-0005, Draining the Reactor Coolant System to $\geq$ 101 Foot Elevation
S2.OP-AB.CONT-0001, Containment Closure
NC.OM-AP.ZZ-0001, Outage Risk Assessment

Notifications

20226458

Other Documents

Calculation S-C-SF-MDC-1800, Decay Heat-up Rates and Curves
Training Drawing CCW-1, Component Cooling Water
Training Drawing SW-1, Service Water - Nuclear
Training Drawing SF-1, Spent Fuel Cooling
SORC Presentation for Salem 2 Cycle 15 LPPT IPTE
Salem 2R14 Final Risk Assessment Report
Contingency Plan for Inventory Control (2R14 Refueling Outage) RCS at Mid-Loop Post-Refueling
Calculation S-2_RC-MEE-1901, Salem Unit 2 Reactor Pressure Vessel Times to Boil and Core Uncover
NUMARC 91-06 Guidelines fo Industry Actions to Assess Shutdown Management - Dec 1991
NLR-N89001 Salem Generating Station - Response to NRC Generic Letter 88-17
NRC Generic Letter 88-17
NUMARC 93-01 Section 11 - Assessment of Risk Resulting from Performance of Maintenance Activities
Temporary Standing Order 05-04, Actions Required for Operations Support During Heavy Grassing
LR-N95081 License Amendment Application - Salem Generation Station
Salem Narrative Operating Logs April 6 through April 1, 2005
SH.OP-AP.ZZ-0107 Attachment 25, Salem Unit 2 Shutdown Safety Assessment Checklist April 6 through April 11, 2005
Salem Unit 2 Shutdown Risk Status Sheet April 6 through April 11, 2005

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

Procedures

S2.OP-IO.ZZ-0003, Hot Standby to Minimum Load
S2.OP-IO.ZZ-0004, Power Operation
S2.OP-IO.ZZ-0005, Minimum Load to Hot Standby
S2.OP-IO.ZZ-0006, Hot Standby to Cold Shutdown
S2.OP-SO.SF-0003, Filling of the Refueling Cavity
S1.OP-IO.ZZ-0003, Hot Standby to Minimum Load

Section 1R15: Operability Evaluations

Procedures

S1.OP-ST.SW-0003, Inservice Testing - 13 Service Water Pump
S1.RA-ST.SW-0003, Inservice Testing 13 Service Water Pump Acceptance Criteria

Drawings

205242

Notifications

20208460, 20236209, 20237973, 20237542, 20237897, 2023815, 20239352,

Orders

70047249, 70047581, 70047707

Other Documents

Vendor Technical Document 316040 (20" 150 lb Duel Plate Check Valve)
IST performance data for 13 service water pump
Troubleshooting/Evolution Plan (13 SW pump, motor, and 11 SW Bay Header)
Technical Issues Fact Sheet (order # 20236209, Low delta-P on the 13 SW Pump)
Weld History Records 70447 and 70448

Section 1R16: Operator Workarounds

Notifications

20238223, 20237542

Orders

70047581, 70047707

Other Documents

Salem Units 1 & 2 Night Order Book
Salem Units 1 & 2 Control Room Operator turnover sheet
Salem Units 1 & 2 Shift Manager turnover sheet
Salem Units 1 & 2 Equipment Operator turnover sheet

Section 1R19: Post-Maintenance Testing

Procedures

SH.MD-GP.ZZ-0240, System Pressure Test at Normal Operating Pressure and Temperature
SH.RA-IS.ZZ-0005, VT-2 Visual Examination of Nuclear Class 1, 2 and 3 Systems
S2.OP-ST.SJ-0003, Inservice Testing Safety Injection Valves, Modes 1-6
SH.MD-GP.ZZ-0240, System Pressure Test at Normal Operating Pressure and Temperature
S2.OP-ST.RPI-0004, IST - Remote Position Verification - Penetration Area
S2.OP-ST.DG-0001, 2A Diesel Generator Surveillance Test
S2.OP-ST.DG-0004, 21 Fuel Oil Transfer System Operability Test
S2.OP-ST.RHR-0004, Inservice Testing Residual Heat Removal Valves
S2.OP-ST.RPI-0003, IST - Remote Position Verification - Cold Shutdown
SC.MD-CM.CVC-0002, Centrifugal Charging Pump Repairs
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Drawings

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Notifications

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Salem Inservice Testing Program Basis Data Sheets - Valves (Table 9-2B, 2SJ60)
Salem Inservice Testing Program Basis Data Sheet - 22RH19

Section 1R20: Refueling and Other Outage Activities

Procedures

NC.OM-AP.ZZ-0001, Outage Risk Assessment
S2.OP-IO.ZZ-0001, Refueling to Cold Shutdown
S2.OP-IO.ZZ-0002, Cold Shutdown to Hot Standby
S2.OP-IO.ZZ-0003, Hot Standby to Minimum Load
S2.OP-IO.ZZ-0005, Minimum Load to Hot Standby
S2.OP-IO.ZZ-0006, Hot Standby to Cold Shutdown
S2.OP-IO.ZZ-0007, Cold Shutdown to Refueling
S2.OP-IO.ZZ-0008, Defueled to Refueling
S2.OP-IO.ZZ-0009, Spent Fuel Pool Manipulation
S2.OP-AB.FUEL-0002, Loss of Refueling Cavity or Spent Fuel Pool Level
S2.OP-AB.RHR-0001, Loss of RHR
S2.OP-AB.RHR-0002, Loss of RHR at Reduced Inventory

S2.OP-ST.CAN-0007, Refueling Operations - Containment Closure
S2.OP-ST.SJ-0010, ECCS - Containment Inspection for Mode 4
S2.OP-ST.SJ-0011, Emergency Core Cooling ECCS - Containment Sump Modes 5-6
S2.OP-SO.SF-0009, Refueling Operations
SC.RE-FR.ZZ-0001, Fuel Handling
S2.OP-SO.RC-0002, Vacuum Refill of the RCS
S2.OP-SO.RC-0005, Draining the Reactor Coolant System >101FT Elevation with Fuel in the Vessel
S2.OP-SO.RC-0006, Draining the Reactor Coolant System <101FT Elevation with Fuel in the Vessel

Notifications

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Contingency Plan for Inventory Control, RCS at Mid-Loop Post-Refueling

Section 1EP2: Alert and Notification System Testing

Notifications

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Section 1EP3: Emergency Response Organization Augmentation

Procedures

NC.EP-DG.ZZ-0005(Z), Rev 0, Emergency Response Callout Tests

Notifications

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Section 1EP4: Emergency Action Level and Emergency Plan Changes

Procedures

PSEG Nuclear Emergency Plan
Emergency Plan Implementing Procedures

Section 1EP5: Correction of Emergency Preparedness Weaknesses and Deficiencies

Procedures

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Sections 2OS1, 2, 3 and 2PS3: Access Control to Radiologically Significant Areas, ALARA Planning and Controls, Radiation Monitoring Instrumentation and Radiological Environmental Monitoring Program

Procedures

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NC.RS-TI.ZZ-0518, Calibration of the Bicron*NE Article Monitor
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    Steam generator channel head entries
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Framatome ANP Environmental Laboratory Dosimetry Services Semi-Annual Quality Assurance Status Report

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Section 4OA2: Identification and Resolution of Problems

Procedures

S2.OP-PT.SW-0003, Flush of Service Water Accumulator Discharge Piping
S1.OP-PT.SW-0006, Service Water Fouling Monitoring Diesel Generators
S1.OP-PM.SW-0001, Flush of Emergency Diesel Generator SW Supply Header
S1.OP-PT.SW-0002, Flush of Emergency SW Supply and Return for the Emergency Air Compressor
S1.OP-PT.SW-0001, Flushing of Emergency Auxiliary Feedwater Supply

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PSEG Memo, 10/29/1992, Service Water Project Pipe Replacement 2R6 and 1R10 Flow Testing
NUREG-0654, “Criteria for Preparation and Evaluation of Radiological Emergency Response Plans and Preparedness in Support of Nuclear Power Plants”
NUREG-0694, “TMI-REIated Requirements for New Operating Licenses”

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Section 4OA5: Other Activities

Procedures

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NC.CC-AP.ZZ-0001, Design Bases/Input For Engineering Changes

Other Documents

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S-C-RC-NGS-0177, Design Specification, Replacement Reactor Vessel Closure Heads for Salem Units 1 and 2
S-C-RC-NGS-0178, Design Specification, Forging Material for Replacement Reactor Vessel Closure Heads for Salem Units 1 and 2
S-2-RC-MDS-0408, Design Specification, Control Rod Drive Mechanism Pressure Housing Assembly (Appurtenance ASME III Class 1) for Salem Unit 2
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SC.MD-PM.ZZ-0018, AC Motor Cleaning Inspection, completed 3/10/05
SC.MD-EU.CRN-0004, Polar Crane Periodic Inspections and Operational Tests, completed 3/10/04
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SECY-03-0054, 4/10/2003, Replacement of North Anna, Unit 2, Reactor Pressure Vessel Head With A Head Manufactured To French Standards
NUREG 0612, Control of Heavy Loads at Nuclear Power Plants

LIST OF ACRONYMS

ALARA	As Low As Is Reasonably Achievable
ANI	Authorized Nuclear Inspectors
ANS	Alert and Notification System
ASME	American Society Mechanical Engineers
B&PV	Boiler and Pressure Vessel
BACC	Boric Acid Corrosion Control
CAQ	Conditions Adverse to Quality
CC	Component Cooling
CFCU	Containment Fan Coil Unit
CFR	Code of Federal Regulations
CMTR	Certified Material Test Reports
CR	Condition Report
CRDM	Control Rod Drive Mechanism
CVC	Chemical and Volume Control
DCP	Design Change Package
DEP	Drill and Exercise Performance
DM	Dissimilar Metal
EAL	Emergency Action Level
ECCS	Emergency Core Cooling System

ECP	Employee Concerns Program
EDGs	Emergency Diesel Generators
EIR	Engineering Information Record
EMRs	End of Manufacturing Reports
EP	Emergency Preparedness
E-Plan	Emergency Plan
EPD	Electronic Personal Dosimeter
ERB	Executive Review Board
ERO	Emergency Response Organization
ET	Eddy Current Testing
IHA	Integrated Head Assembly
IMAP	Integrated Master Assessment Plan
IMC	Inspection Manual Chapter
ISI	Inservice Inspection
LER	Licensee Event Report
LERF	Large Early Release Frequency
LHP	Lower Head Penetration
MAR	Management Action Request
MIMS	Metal Impact Monitoring System
NCV	Non-cited Violation
NDE	Non-Destructive Examination
NOSC	Nuclear Operating Services Contract
NRC	Nuclear Regulatory Commission
NRR	NRC Office of Nuclear Reactor Regulation
ODCM	Offsite Dose Calculation Manual
Ods	Operability Determinations
OEH	Outage Equipment Hatch
PARS	Publicly Available Records
PI	Performance Indicator
PM	Preventive Maintenance
PMT	Post-maintenance Testing
PSEG	Public Service Enterprise Group
PSI	Pre-service Inspection
PT	Liquid Dye Penetrant Testing
PWSCC	Primary Water Stress Corrosion Cracking
QA	Quality Assurance
RCA	Radiologically Controlled Area
RCS	Reactor Coolant System
REMP	Radiological Environmental Monitoring Program
RHR	Residual Heat Removal
ROP	Reactor Oversight Program
RPV	Reactor Pressure Vessel
RVCH	Reactor Vessel Closure Head
RVHV	Reactor Vessel Head Vent
RVLIS	Reactor Vessel Level Indication System
RWP	Radiation Work Permit
SCWE	Safety Conscious Work Environment

SDP	Significance Determination Process
SFP	Spent Fuel Pool
SIA	Structural Integrity Associates
SORC	Station Operations Review Committee
SSC	Structure, System, or Component
SSFF	Safety System Function Failure
SW	Service Water
TLD	Thermoluminescent Dosimeter
TOFD	Time of Flight Diffraction
TS	Technical Specifications
TSC	Technical Support Center
UFSAR	Updated Final Safety Analysis Report
URI	Unresolved Item
UT	Ultrasonic Testing
VT	Visual Examination