UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION I
475 ALLENDALE ROAD
KING OF PRUSSIA, PA 19406-1415

August 12, 2009

Mr. Thomas P. Joyce
President and Chief Nuclear Officer
PSEG Nuclear LLC - N09
P.O. Box 236
Hancock's Bridge, NJ 08038

SUBJECT: SALEM NUCLEAR GENERATING STATION, UNIT NOS. 1 AND 2 - NRC INTEGRATED INSPECTION REPORT 05000272/2009003 and 05000311/2009003

Dear Mr. Joyce:

On June 30, 2009, the U.S. Nuclear Regulatory Commission (NRC) completed an integrated inspection at the Salem Nuclear Generating Station, Unit Nos. 1 and 2. The enclosed inspection report documents the inspection results which were discussed on July 9, 2009, with Mr. Eilola 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 one NRC-identified finding and one self-revealing finding of very low safety significance (Green). One of these findings was determined to involve a violation of NRC requirements. However, because of the very low safety significance and because it is entered into your corrective action program, the NRC is treating this finding as a non-cited violation (NCV) consistent with Section VI.A.1 of the NRC Enforcement Policy. If you contest the 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, United States Nuclear Regulatory Commission, Washington, DC 20555-0001; and the NRC Resident Inspector at the Salem Generating Station. In addition, if you disagree with the characterization of any finding in this report, you should provide a response within 30 days of the date of this inspection report, with the basis for your disagreement, to the Regional Administrator, Region 1, and the NRC Resident Inspector at

Salem Generating Station. The information you provide will be considered in accordance with Inspection Manual Chapter 0305.

In accordance with 10 CFR 2.390 of the NRC's "Rules of Practice," a copy of this letter, 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/

Arthur L. Burritt, Chief
Projects Branch 3
Division of Reactor Projects

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

Enclosure: Inspection Report 05000272/2009003 and 05000311/2009003
w/Attachment: Supplemental Information

cc w/encl:
W. Levis, President and Chief Operating Officer, PSEG Power
R. Braun, Site Vice President
P. Davison, Director of Nuclear Oversight
E. Johnson, Director of Finance
E. Eilola, Salem Plant Manager
J. Keenan, Manager Licensing, PSEG
D. Sowers, Director of Public Safety
P. Baldauf, Assistant Director, NJ Radiation Protection Programs
P. Mulligan, Chief, NJ Bureau of Nuclear Engineering, DEP
H. Otto, Ph.D., Administrator, DE Interagency Programs, DNREC Div of Water Resources
Consumer Advocate, Office of Consumer Advocate, Commonwealth of Pennsylvania
N. Cohen, Coordinator - Unplug Salem Campaign
E. Zobian, Coordinator - Jersey Shore Anti Nuclear Alliance
A. Muller, Executive Director, Green Delaware
V. Zabielski, General Solicitor, PSEG

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/
Arthur L. Burritt, Chief
Projects Branch 3
Division of Reactor Projects

Distribution w/encl.
S. Collins, RA
M. Dapas, DRA
D. Lew, DRP
J. Clifford, DRP
A. Burritt, DRP
L. Cline, DRP
A. Turilin, DRP
R. Moore, DRP
D. Schroeder, DRP, SRI
H. Balian, DRP, RI
K. Venuto, DRP, Resident OA
L. Trocine, RI OEDO
R. Nelson, NRR
H. Chernoff, NRR
R. Ennis, NRR, PM
C. Sanders, NRR, Backup
N. Valentine, NRR
ROPreports@nrc.gov
Region I Docket Rm (w/concurrences)

ML092240226

SUNSI Review Complete: AT (Reviewer's Initials)

DOCUMENT NAME: G:\DRP\BRANCH3\INSPECTION\REPORTS\ISSUED\SAL0903.DOC

After declaring this document "An Official Agency Record" it **will** be released to the Public.

To receive a copy of this document, indicate in the box: "**C**" = Copy without attachment/enclosure "**E**" = Copy with attachment/enclosure "**N**" = No copy

OFFICE	RI/DRP		RI/DRP		RI/DRP			
NAME	DSchroeder/ AT for		ATurilin/ AT		ABurritt/ ALB			
DATE	08 /11 /09		08/11/09		08/12/09			

OFFICIAL RECORD COPY

U.S. NUCLEAR REGULATORY COMMISSION

REGION I

Docket Nos:	50-272, 50-311
License Nos:	DPR-70, DPR-75
Report No:	05000272/2009003 and 05000311/2009003
Licensee:	PSEG Nuclear LLC (PSEG)
Facility:	Salem Nuclear Generating Station, Unit Nos. 1 and 2
Location:	P.O. Box 236 Hancocks Bridge, NJ 08038
Dates:	April 1, 2009 through June 30, 2009
Inspectors:	D. Schroeder, Senior Resident Inspector H. Balian, Resident Inspector P. McKenna, Reactor Inspector S. Pindale, Senior Reactor Inspector J. Furia, Senior Health Physicist
Approved By:	Arthur L. Burritt, Chief Projects Branch 3 Division of Reactor Projects

TABLE OF CONTENTS

SUMMARY OF FINDINGS

IR 05000272/2009003, 05000311/2009003; 04/01/2009 - 06/30/2009; Salem Nuclear Generating Station Unit Nos. 1 and 2; Maintenance Effectiveness, Operability Evaluations.

The report covered a three-month period of inspection by resident inspectors, and an announced inspection by a regional radiation specialist, and a regional reactor safety inspector. One Green non-cited violation (NCV), and one Green finding were identified. The significance of most findings is indicated by their color (Green, White, Yellow, or Red) using Inspection Manual Chapter (IMC) 0609, "Significance Determination Process" (SDP). Findings for which the SDP does not apply may be Green or be assigned a severity level after NRC management review. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG-1649, "Reactor Oversight Process," Revision 4, dated December 2006.

A. NRC-Identified and Self-Revealing Findings

Cornerstone: Mitigating Systems

- Green. The NRC identified a NCV of 10 CFR 50.65 because PSEG did not include the service water intake structure (SWIS) sump within the scope of the Salem maintenance rule program and consequently did not recognize that preventive maintenance on the SWIS sump was not effective. Failure to perform preventive maintenance on the SWIS sump led to an accumulation of water in the number 2 SWIS bay and adversely affected operability and reliability of the 22 service water strainer and pump.

  The finding is more than minor because it is associated with the equipment performance attribute of the Mitigating Systems cornerstone and because it affects the associated cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. On April 12, 2009, bay 2 of the SWIS sump failed and allowed water accumulation to a depth of 21-inches, adversely affecting the reliability of the SW pump and strainer. The inspectors determined that the finding was of very low safety significance (Green) per Inspection Manual Chapter 0609, Attachment 4, "Phase 1 – Initial Screening and Characterization of Findings" (IMC 0609.04). The performance deficiency has a cross-cutting aspect in the area of problem identification and resolution because PSEG did not thoroughly evaluate SWIS sump failures such that the resolutions address causes and extent of conditions [P.1(c)]. PSEG had ten SWIS sump pump failures since January 2008. The evaluation of those events did not recognize that the SWIS sump is relied upon to protect the SWPs from flooding. (Section 1R12)

  Green: A self-revealing finding of very low safety significance was identified because PSEG did not implement adequate preventive maintenance for the turbine driven auxiliary feedwater (AFW) pump speed governor. Consequently,

the governor oil conditions degraded causing governor binding and speed oscillations that required the 13 AFW pump to be tripped during testing, resulting in unavailability of the 13 AFW pump. PSEG's corrective actions included replacement of the 13 AFW pump governor, increased oil sampling and oil replacement for the AFW pump governors, and a reduction in the governor replacement periodicity from 90 to 72 months.

This finding was more than minor because it was associated with the equipment performance attribute of the Mitigating Systems cornerstone and because it affects the associated cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. Specifically, the 13 AFW pump was unavailable for 46 hours following the oscillations observed during the quarterly surveillance test. The inspectors conducted a Phase 1 screening of the finding in accordance with IMC 0609, Attachment 0609.04, "Initial Screening and Characterization of Findings", and determined that the finding was of very low safety significance (Green). The inspectors did not identify a cross-cutting aspect associated with this finding because decisions made associated with the preventive maintenance change occurred several years ago and were not reflective of current performance. The preventive maintenance change request process has been replaced with the equipment reliability process and the performance centered maintenance (PCM) process. PCM templates have operating experience and vendor recommendations integral to the template, not merely listed as procedure references, which was the case with previous equipment reliability procedures. (Section 1R15)

B. Licensee-Identified Violations

None

REPORT DETAILS

Summary of Plant Status

Salem Nuclear Generating Station Unit 1 (Unit 1) began the period at full power. On June 12, operators lowered Unit 1 to 85 percent power when an electrical system malfunction caused a reduction in condenser cooling water flow. Operators returned Unit 1 to full power on June 13. Unit 1 operated at or near full power for the remainder of the inspection period.

Salem Nuclear Generating Station Unit 2 (Unit 2) began the period at full power. On April 10, operators lowered Unit 2 to 82 percent power when an electrical system malfunction caused a reduction in condenser cooling water flow. Operators returned Unit 2 to full power on April 11. On May 11, operators lowered Unit 2 to 87 percent power to conduct main turbine valve testing. Operators returned Unit 2 to full power the same day. On June 12, operators lowered Unit 2 to 85 percent power when an electrical system malfunction caused a reduction in condenser cooling water flow. Operators returned Unit 2 to full power on June 13. Unit 2 operated at or near full power for the remainder of the inspection period.

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, Barrier Integrity and Emergency Preparedness

1R01 Adverse Weather Protection (71111.01 - 2 samples)

.1 Summer Readiness of Offsite and Alternate AC Power Systems

a. Inspection Scope

The inspectors completed one adverse weather inspection sample to evaluate the readiness of offsite power to the Salem units prior to the summer season when electrical grid stability can be most challenged. The inspectors verified that PSEG provided procedure requirements or guidance to monitor and maintain availability and reliability of the offsite AC power (OSP) system prior to and during adverse weather conditions. Specifically, the inspectors verified that the procedures addressed:

- The actions to be taken when notified by the Electrical System Operations Center (ESOC) of the PJM interconnection that the post-trip voltage of the OSP system at Salem will not be acceptable to assure the continued operation of the safety-related loads without transferring to the emergency diesel generators.
- The compensatory actions to be performed if ESOC cannot predict the post-trip voltage.
- Re-assessment of plant risk for maintenance activities that could affect grid reliability or OSP system availability to the Salem units.
- Communication requirements between Salem and the ESOC regarding plant changes that could impact the transmission system, or the capacity of the transmission system to provide adequate OSP.

The inspectors also reviewed PSEG's seasonal readiness preparations for the summer season specific to the main power transformers and the OSP system. The inspectors interviewed engineering and work control personnel and reviewed work orders and completed portions of WC-AA-107, Seasonal Readiness, to verify that PSEG took measures to ensure the reliability of the main transformers and the OSP system during the summer season. The documents reviewed during this inspection are listed in the Attachment.

b. Findings

No findings of significance were identified.

.2 Readiness for Seasonal Extreme Weather Conditions

a. Inspection Scope

The inspectors completed one adverse weather inspection sample for the onset of hot weather. The inspectors reviewed hot weather preparations to verify PSEG adequately prepared equipment to operate reliably in extreme hot weather conditions. Specifically, the inspectors interviewed engineering and operations personnel, and walked down the service water intake structure (SWIS), the switchgear and the control area chiller system, and the switchyard. The inspectors verified that design features used to maintain these systems functional during hot weather conditions were adequately maintained. The documents reviewed during this inspection are listed in the Attachment.

b. Findings

No findings of significance were identified.

1R04 Equipment Alignment (71111.04 - 4 samples, 71111.04S – 1 sample)

.1 Partial Walk down

a. Inspection Scope

The inspectors completed four partial system walk down inspection samples. The inspectors walked down the systems to verify the operability of redundant or diverse trains and components when safety equipment was inoperable. The inspectors focused their review on potential discrepancies that could impact the function of the system and increase plant risk. The inspectors reviewed applicable operating procedures, walked down control systems components, and verified that selected breakers, valves, and support equipment were in the correct position to support system operation. The inspectors also verified that PSEG properly utilized its corrective action program to identify and resolve equipment alignment problems that could cause initiating events or impact the capability of mitigating systems or barriers. Documents reviewed are listed in the Attachment. The inspectors walked down the systems listed below:

- Unit 1 safety injection system during and following repairs to 11 safety injection pump discharge check valve, 11SJ35, on April 23, 2009;

- Unit 1 residual heat removal system following a potential water hammer occurrence on April 1, 2009;
- Unit 1 28 volt DC power distribution following preventive maintenance on April 8, 2009; and
- Unit 1 service water system with 16 service water pump out of service on June 25, 2009.

b. Findings

No findings of significance were identified.

.2 Complete Walk down (71111.04S - 1 sample)

a. Inspection Scope

The inspectors conducted one complete walk down of the Unit 2 Chemical and Volume Control System (CVCS). The inspectors used PSEG procedures and other documents to verify proper system alignment and functional capability. The inspectors independently verified the alignment and status of CVCS pump and valve electrical power, labeling, hangers and supports, and associated support systems. The walk down also included evaluation of system piping and equipment to verify pipe hangers were in satisfactory condition, oil reservoir levels were normal, pump rooms and pipe chases were adequately ventilated, system parameters were within established ranges, and equipment deficiencies were appropriately identified. The inspectors interviewed engineering personnel and reviewed corrective action evaluations associated with the system to determine whether equipment alignment problems were identified and appropriately resolved. Documents reviewed are listed in the Attachment.

b. Findings

No findings of significance were identified.

1R05 Fire Protection (71111.05Q - 8 samples)

.1 Fire Protection - Tours

a. Inspection Scope

The inspectors completed eight fire protection quarterly inspection samples. The inspectors performed walk downs to assess the material condition and operational status of fire protection features. The inspectors verified that combustibles and ignition sources were controlled in accordance with PSEG's administrative procedures; fire detection and suppression equipment was available for use; that passive fire barriers were maintained in good material condition; and that compensatory measures for out-of-service, degraded, or inoperable fire protection equipment were implemented in accordance with PSEG's fire plan. Documents reviewed are listed in the Attachment. The inspectors evaluated the fire protection areas listed below:

- Unit 1 and 2 containment while at-power;
- Unit 1 and 2 mechanical piping penetration area;
- Unit 1 auxiliary equipment area, elevations 45' and 55' (Residual Heat Removal (RHR) Vaults);
- Unit 1 and 2 auxiliary equipment area, elevation 64' (CVCS Holdup Tank Area); and
- Unit 1 inner penetration area.

b. Findings

No findings of significance were identified.

1R06 Flood Protection Measures (71111.06 - 1 sample)

Internal Flooding

a. Inspection Scope

The inspectors completed one internal flooding area inspection sample. The inspectors evaluated flood protection measures for the Unit 1 and Unit 2 service water intake structure. The inspectors walked down the areas to assess operational readiness of various features in place to protect redundant safety-related components. These features included plant drains, flood barrier curbs, and wall penetration seals. The inspectors also reviewed the results of flooding evaluations, preventive maintenance history, and corrective action notifications associated with flood protection measures. Documents reviewed are listed in the Attachment.

b. Findings

One finding of significance was identified and is documented below in section 1R12. **(NCV 05000311/2009003-001, Improper Maintenance Rule Scoping of the SWIS Sump System)**

1R11 Licensed Operator Requalification Program (71111.11Q - 1 sample)

.1 Requalification Activities Review by Resident Staff.

a. Inspection Scope

The inspectors completed one quarterly licensed operator requalification program sample. Specifically, the inspectors observed an evaluated scenario at the beginning of the training week administered to a single crew on April 28, 2009. The scenario included a chlorine release in the service water intake structure, followed by a loss of service water, a reactor trip and loss of AC electric power. Documents reviewed are listed in the Attachment.

b. Findings

No findings of significance were identified.

1R12 Maintenance Effectiveness (71111.12Q - 3 samples)

a. Inspection Scope

The inspectors completed three quarterly maintenance effectiveness inspection samples. The inspectors reviewed performance monitoring and maintenance effectiveness issues for the service water, feedwater containment isolation, and service water intake structure systems. The inspectors reviewed PSEG's process for monitoring equipment performance and assessing preventive maintenance effectiveness. The inspectors verified that systems and components were monitored in accordance with the maintenance rule program requirements. The inspectors compared documented functional failure determinations and unavailability hours to those being tracked by PSEG to evaluate the effectiveness of PSEG's condition monitoring activities and to determine whether performance goals were being met. The inspectors reviewed applicable work orders, corrective action notifications, and preventive maintenance tasks. The documents reviewed are listed in the Attachment. The inspectors evaluated the systems listed below:

- Unit 2, 21 service water strainer;
- Unit 2, service water intake structure (SWIS) sump number 2; and
- Unit 2, feedwater containment isolation valves.

b. Findings

Introduction: The inspectors identified a Green NCV of 10 CFR 50.65 because PSEG did not include the SWIS sump within the scope of the Salem maintenance rule program and consequently did not recognize that preventive maintenance on the SWIS sump was not effective. Failure to perform preventive maintenance on the SWIS sump led to an accumulation of water in the number 2 SWIS bay and adversely affected operability and reliability of the 22 service water strainer and pump.

Description: The NRC identified that PSEG did not correctly scope the SWIS sump system into the Salem maintenance rule program. 10 CFR 50.65 (b)(2)(ii) requires that non-safety related systems, structures and components (SSCs) whose failure to function could prevent safety-related SSCs from fulfilling their safety-related functions be in scope of the maintenance rule program. 10 CFR 50.65 (a) requires effective maintenance or monitoring of in-scope SSCs to ensure they can fulfill their function.

The Salem FSAR description of the service water system states that service water pump (SWP) motors are protected from flooding by the watertight SWIS compartments and sump pumps. The SWIS sumps protect the safety-related service water system from in-leakage by collecting and pumping water out of the associated SWIS bay or alerting control room operators of an abnormally high water level alarm. The majority of the routine in-leakage, about five gallons per minute per pump, comes from SWP packing gland that is routed directly to the sump.

On April 12, 2009, operators found the number 2 SWIS bay flooded to a depth of 21-inches. PSEG promptly secured the 22 SWP to stop in-leakage from the pump packing gland and dewatered the bay using a temporary sump pump. PSEG subsequently found

degradation of both the sump pump and high level alarm. Foreign material had blocked the suction of the sump pump and prevented the pump from moving water. A bent tie rod on the high level alarm prevented the alarm from functioning. PSEG corrected both conditions and restored the sump to functional status.

An electrical junction box providing power to the 22 service water strainer blow down valve, 22SW24, was located below the twenty-one inch water level and was submerged during the high water level incident. The design of this junction box is weather-proof, not water-proof. Consequently, operability of the 22 service water strainer and pump could not be immediately determined. PSEG subsequently tested and demonstrated operability of the 22SW24.

PSEG experienced ten SWIS sump pump failures since January 2008. Accordingly, opportunities to recognize that the non-safety related SWIS sumps are relied upon to protect the safety related SWPs were missed. Further, PSEG did not specify adequate corrective actions for SWIS sump pump failures. The inspectors determined that the maintenance history and associated system performance problems indicated that PSEG missed opportunities to place the SWIS sump in maintenance rule scope and, as a result, did not effectively maintain the function of the SWIS sump through appropriate preventive maintenance.

Corrective actions include re-instituting the weekly functional tests of the sump high level alarm that had been discontinued in 2002. The Salem maintenance rule expert panel convened and placed the SWIS sumps in maintenance rule scope. System Engineering is currently developing performance criteria appropriate for the SWIS sump and reviewing other sump systems for extent of condition.

Analysis: The inspectors determined this finding was a performance deficiency because PSEG did not scope the SWIS sump into the maintenance rule program and, consequently, did not demonstrate that the SWIS sump performance was effectively controlled through appropriate preventive maintenance. The inspectors determined that this finding was more than minor per Inspection Manual Chapter 0612, Appendix E, “Examples of Minor Issues”, example 7.d. The performance deficiency was verified to be more than minor because it is associated with the equipment performance attribute of the Mitigating Systems cornerstone and because it affects the associated cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. On April 12, 2009, bay 2 of the SWIS sump failed and allowed water accumulation to a depth of 21-inches, adversely affecting the reliability of the 22 SW pump and strainer.

The inspectors completed a Phase 1 screening of the finding per Inspection Manual Chapter 0609, Attachment 4, “Phase 1 – Initial Screening and Characterization of Findings” (IMC 0609.04) and determined the finding to be of very low safety significance (Green) because the performance deficiency was not a design deficiency, did not result in an actual loss of safety function, and did not screen as potentially risk significant due to external initiating events.

The performance deficiency has a cross-cutting aspect in the area of problem identification and resolution because PSEG did not thoroughly evaluate SWIS sump

failures such that the resolutions address causes and extent of conditions. PSEG had ten SWIS sump pump failures between January 2008 and April 2009. The evaluation of those events did not recognize that the SWIS sump is relied upon to protect the SWPs from flooding. [P.1(c)]

Enforcement: 10 CFR 50.65 (b)(2)(ii), "Requirements for monitoring the effectiveness of maintenance at nuclear power plants," requires that the scope of the monitoring program specified in paragraph (a)(1) include non-safety related SSCs whose failure can prevent safety-related SSCs from fulfilling their safety-related functions. The SWIS sumps are a non-safety related system designed to protect the safety related SWPs from internal flooding by pumping water out of the sump or alerting control room operators of a high water level. Contrary to the above, as of April 12, 2009, PSEG did not include the SWIS sumps in the scope of the monitoring program specified in paragraph (a)(1). Specifically, PSEG did not effectively control performance of the SWIS sump through appropriate preventive maintenance and consequently, the sump did not perform its intended function on April 12, 2009. Because this issue was of very low safety significance and has been entered into PSEG's corrective action program as notification 20410166, this violation is being treated as a NCV, consistent with Section VI.A, of the NRC Enforcement Policy. **(NCV 05000311/2009003-001, Improper Maintenance Rule Scoping of the SWIS Sump System)**

1R13 Maintenance Risk Assessments and Emergent Work Control (71111.13 - 5 samples)

a. Inspection Scope

The inspectors completed five maintenance effectiveness and emergent work control inspection samples. The inspectors reviewed the maintenance activities to verify that the appropriate risk assessments were performed as specified by 10 CFR 50.65(a)(4) prior to removing equipment for work. The inspectors reviewed the applicable risk evaluations, work schedules and control room logs for these configurations. PSEG's risk management actions were reviewed during shift turnover meetings, control room tours, and plant walk downs. The inspectors also used PSEG's on-line risk monitor (Equipment Out-Of-Service workstation) to gain insights into the risk associated with these plant configurations. The inspectors reviewed notifications documenting problems associated with risk assessments and emergent work evaluations. Documents reviewed are listed in the Attachment. The inspectors assessed the plant configurations listed below:

- Unit 2 planned unavailability of the 23 TDAFW pump concurrent with unavailability of automatic actuation of pressurizer (PZR) power operated relief valve (PORV) 2PR2;
- Unit 1 planned unavailability of the 1B EDG;
- Unit 1 and Unit 2 planned unavailability of the 3 station power transformer (SPT) and station gas turbine generator;
- Unit 2 planned unavailability of the 21 service water pump concurrent with unplanned unavailability of one source of offsite electrical power caused by failure of the 4 SPT; and
- Unit 1 planned unavailability of the 11 safety injection pump for discharge check valve repair.

b. Findings

No findings of significance were identified.

1R15 Operability Evaluations (71111.15 - 6 samples)

a. Inspection Scope

The inspectors completed six operability evaluation inspection samples. The inspectors reviewed the operability determinations for degraded or non-conforming conditions associated with:

- Unit 2 number 22 containment spray pump room cooler leak on inlet flange;
- Unit 1 concurrent degradation of containment pressure detectors PT-948A and PT-948D;
- Unit 1 borated water sources and flow paths with reduced inventory in the boric acid storage tanks;
- Unit 2 component cooling water with a failed surge tank vent valve;
- Unit 1 emergency core cooling systems with potential gas voiding in the reactor coolant system cold leg injection nozzle; and
- Unit 2 service water with planned unavailability of the 21 service water pump and unplanned unavailability of one source of offsite electrical power caused by failure of the 4 SPT.

The inspectors reviewed the technical adequacy of the operability determinations to ensure the conclusions were justified. The inspectors also walked down accessible equipment to corroborate the adequacy of PSEG's operability determinations. Additionally, the inspectors reviewed other PSEG identified safety-related equipment deficiencies during this report period and assessed the adequacy of their operability screenings. Documents reviewed are listed in the Attachment.

b. Findings

Introduction: A self-revealing finding of very low safety significance (Green) was identified because PSEG did not implement adequate preventive maintenance for the turbine driven auxiliary feedwater (AFW) pump speed governor. Consequently, the governor oil conditions degraded causing governor binding and speed oscillations that required the 13 AFW pump to be tripped during testing, resulting in unavailability of the 13 AFW pump.

Description: The auxiliary feedwater system serves as a backup system for supplying feedwater to the secondary side of the steam generators at times when the main feedwater system is not available. The AFW system is equipped with one turbine driven and two motor driven auxiliary feed pumps.

On February 9, 2009, the 13 AFW pump was started for performance of a quarterly surveillance test. Following start up, the pump was tripped locally by the equipment operator because the pump speed was observed to be oscillating and exceeded the procedural speed limit of 4000 rpm. Troubleshooting by PSEG determined that the

governor was the cause of the speed oscillations and it was replaced. After testing the as found condition at a vendor repair facility, the malfunctioning governor was disassembled. An inspection determined that water present in the governor oil caused corrosion of internal parts, wear particles were found in the oil, and scoring was present on piston actuator surfaces. PSEG conducted a root cause investigation and determined that the governor binding was caused by long term degradation of the internal components of the governor due to accumulation of water in the governor oil.

The 13 AFW pump governor oil had been in service for over 90 months and had degraded over time, as moisture was introduced into the oil through an atmospheric vent port. Shortly after the 13 AFW pump governor was installed in May, 2001, PSEG personnel deleted the preventive maintenance (PM) task of replacing the governor oil on an 18 month periodicity. PSEG's basis for this change was that the governor was replaced every 54 months, and that the governor oil was suitable for a 54 month replacement period. Later, additional changes to the PM program extended the replacement interval for the governor to 90 months, with no consideration given to the need to sample or replace the governor oil. PSEG personnel did not consider industry operating experience during the maintenance schedule change process. Industry operating experience recorded a similar AFW pump governor failure in 1990 due to degraded oil quality, and could have alerted PSEG personnel of the importance of periodically sampling and replacing the governor oil. Condition based monitoring of the governor oil quality also presented an opportunity to detect degradation of the governor. In November 2005, a governor oil sample was taken based on foaming and discoloration of the oil in the sight glass. The governor maintenance troubleshooting section of the vendor manual states that the oil used in the governor should be clean and free of foreign particles to obtain maximum performance from the governor. The vendor manual recommends changing the governor oil immediately when it starts to break down or darken.

The inspectors determined that the lack of adequate preventive maintenance caused by deleting the 18 month oil change for the 13 AFW pump governor without following the procedure for processing a preventive maintenance change request contained in PSEG procedure NC.ER-AP.ZZ-0010, Equipment Reliability Process, was a performance deficiency. The preventive maintenance change request section of the procedure listed twenty-three reference documents which should be included, as applicable, to support the basis or reason for submitting a PM change request. Specifically, PSEG personnel did not support the basis for the change request by including reference documents contained in the list such as vendor recommendations, and available operating experience.

Several corrective actions have been initiated based on PSEG's root cause evaluation for this event. These have included replacement of the 13 AFW pump governor, increased oil sampling and oil replacement for the AFW pump governors, and a reduction in the governor replacement periodicity from 90 to 72 months. The oil was replaced and a sample was sent for analysis on the Unit 2 steam driven (23) AFW pump governor. The lack of technical rigor in the PM change process for critical components may be applicable to other critical components. A preventive maintenance oversight committee has been established to provide additional oversight to review proposed changes to critical component PMs.

Analysis: This finding was more than minor because it was associated with the equipment performance attribute of the Mitigating Systems cornerstone and because it adversely affected the associated cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. Specifically, the 13 AFW pump was unavailable for 46 hours following the oscillations observed during the quarterly surveillance test. The inspectors conducted a Phase 1 screening of the finding in accordance with IMC 0609, Attachment 0609.04, "Initial Screening and Characterization of Findings", and determined that the finding was of very low safety significance (Green). The redundant train of AFW was available, and no additional risk significant equipment was out of service during the time that the 13 AFW pump was unavailable. Additionally, testing of the degraded governor on a test bench demonstrated that the speed oscillations diminished after approximately one minute and the pump was capable of performing its design function for its mission time of 24 hours.

The inspectors did not identify a cross-cutting aspect associated with this finding because decisions made associated with the preventive maintenance change occurred several years ago and were not reflective of current performance. The preventive maintenance change request process has been replaced with the equipment reliability process and the performance centered maintenance (PCM) process. PCM templates have operating experience and vendor recommendations integral to the template, not merely listed as procedure references, which was the case with previous equipment reliability procedures.

Enforcement: Enforcement action does not apply because the performance deficiency did not involve a violation of a regulatory requirement. Although PSEG did not effectively incorporate industry operating experience and vendor guidance when changing preventive maintenance requirements for the 13 AFW pump as required by PSEG's PM program, the PM change process does not fall under NRC regulatory requirements. **(FIN 05000272/2009003-002, Inadequate Maintenance of the 13 AFW Pump Governor)**

1R18 Plant Modifications (71111.18 – 1 sample)

.1 Permanent Modification

a. Inspection Scope

The inspectors completed one plant modification inspection sample. The inspectors reviewed a permanent modification to Unit 1 Safety Parameter Display System (SPDS) uninterruptible power supply sources under design change package (DCP) 80091021. This review included system walk downs, interviews with plant engineers, and functional comparison of the new battery charger and batteries to the FSAR description. The inspectors also reviewed design adequacy of the modification, preparation, staging, and implementation of the modification, and the post modification test plan. This modification replaced a battery charging system that had become difficult to maintain due to obsolescence. Documents reviewed are listed in the attachment.

b. Findings

No findings of significance were identified.

1R19 Post-Maintenance Testing (71111.19 - 6 samples)

a. Inspection Scope

The inspectors completed six post-maintenance testing inspection samples. The inspectors observed portions of and/or reviewed the results of the post-maintenance test activities. The inspectors verified that the effect of testing on the plant was adequately addressed by control room and engineering personnel; testing was adequate for the maintenance performed; acceptance criteria were clear, demonstrated operational readiness and were consistent with design and licensing basis documentation; test instrumentation was calibrated and used within its required range and accuracy; tests were performed, as written, with applicable prerequisites satisfied; and equipment was returned to an operational status and ready to perform its safety function. Documents reviewed are listed in the Attachment. The inspectors evaluated the post-maintenance tests for the following maintenance items listed below:

- Work Order (WO) 30135572, 21 chiller preventive maintenance;
- WO 60079153, replacement of gas turbine generator batteries;
- WO 60082743, corrective maintenance of 11 safety injection pump discharge check valve, 11SJ34;
- WO50108975, preventive maintenance of 1B1 28 VDC battery charger;
- WO60079598, Unit 1 auxiliary building supply and exhaust fan repairs; and
- WO60080170, replacement of 22 chiller motor.

b. Findings

No findings of significance were identified.

1R22 Surveillance Testing (71111.22 - 6 samples)

a. Inspection Scope

The inspectors completed six surveillance testing inspection samples. The inspectors observed portions of and/or reviewed results for the surveillance tests to verify, as appropriate, whether the applicable system requirements for operability were adequately incorporated into the procedures and that test acceptance criteria were consistent with procedure requirements, the technical specification requirements, the UFSAR, and ASME Section XI for pump and valve testing. Documents reviewed are listed in the Attachment. The inspectors evaluated the surveillance tests listed below:

- S1.OP-ST.DG-0014, “1C Diesel Generator Endurance Run” on May 13, 2009;
- S1.OP-ST.SSP-0010, “Engineered Safety Features SSPS Slave Relays Test – Train ‘B’” on March 19, 2009;
- S1.OP-ST.SJ-0009, “Emergency Core Cooling ECCS Subsystems – Tavg ≥ 350°F on April 17, 2009;

- S2.IC-CC.RCP-0005, 22 “Loop Delta T and T Average Channel Calibration” on April 7, 2009;
- S2.OP-ST.PZR-0002, “Inservice Testing on PORV Block Valves” on April 27, 2009; and
- S1.OP-ST.AFW-0003, “Inservice Testing on 13 Auxiliary Feedwater Pump” on June 24, 2009 (IST).

b. Findings

No findings of significance were identified.

Cornerstone: Emergency Preparedness

1EP6 Drill Evaluation (71114.06 - 1 sample)

a. Inspection Scope

The inspectors completed one drill evaluation inspection sample. On April 28, the inspectors observed a drill from the control room simulator during an evaluated annual licensed operator requalification training scenario. The inspectors evaluated operator performance relative to developing event classifications and notifications. The inspectors reviewed the Salem Event Classification Guides. The inspectors referenced Nuclear Energy Institute 99-02, “Regulatory Assessment PI Guideline,” Revision 5, and verified that PSEG correctly counted the evaluated scenario’s contribution to the NRC PI for drill and exercise performance.

b. Findings

No findings of significance were identified.

2. RADIATION SAFETY

Cornerstone: Occupational Radiation Safety

2OS1 Access Control to Radiologically Significant Areas (71121.01 - 10 samples)

a. Inspection Scope

The inspectors reviewed all PSEG performance indicators for the occupational exposure cornerstone for follow-up.

The inspectors reviewed radiation work permits for airborne radioactivity areas with the potential for individual worker internal exposures of >50 mrem committed effective dose equivalent (20 DAC-hrs). For these selected airborne radioactive material areas, the inspectors verified barrier integrity and engineering controls performance (e.g., HEPA ventilation system operation).

The inspectors reviewed and assessed the adequacy of PSEG’s internal dose assessment for any actual internal exposure greater than 50 mrem committed effective

dose equivalent. No exposures of this magnitude have occurred at PSEG's facility in the past 12 months.

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

The inspectors reviewed PSEG's self assessments, audits, Licensee Event Reports, and Special Reports related to the access control program since the last inspection. The inspectors verified that identified problems were entered into the corrective action program for resolution.

The inspectors reviewed corrective action reports related to access controls. The inspectors interviewed staff and reviewed documents to determine whether the follow-up activities are being conducted in an effective and timely manner commensurate with their importance to safety and risk:

1. Initial problem identification, characterization, and tracking.
2. Disposition of operability/reportability issues.
3. Evaluation of safety significance/risk and priority for resolution.
4. Identification of repetitive problems.
5. Identification of contributing causes.
6. Identification and implementation of effective corrective actions.
7. Resolution of non-cited violations tracked in the corrective action system.
8. Implementation/consideration of risk significant operational experience feedback.

For repetitive deficiencies or significant individual deficiencies in problem identification and resolution identified above, the inspectors determined that PSEG's self-assessment activities were also identifying and addressing these deficiencies.

The inspectors reviewed PSEG documentation packages for all performance indicator events occurring since the last inspection. The inspectors determined that none of these performance indicator events involved dose rates >25 R/hr at 30 centimeters or >500 R/hr at 1 meter.

The inspectors reviewed radiological problem reports since the last inspection that found that the cause of the event was due to radiation worker errors. The inspectors determined if there was an observable pattern traceable to a similar cause. The inspectors determined that this perspective matched the corrective action approach taken by PSEG to resolve the reported problems. The inspectors discussed with the radiation protection manager any problems with the correction actions planned or taken.

The inspectors reviewed radiological problem reports since the last inspection that found the cause of the event was radiation protection technician error. The inspectors determined that there was no observable pattern traceable to a similar cause. The inspectors determined that this perspective matched the corrective action approach taken by PSEG to resolve the reported problems.

The inspectors evaluated PSEG performance against the requirements contained in 10 CFR 20, and Technical Specification 6.12.

b. Findings

No findings of significance were identified.

2OS2 ALARA Planning and Controls (71121.02 - 2 samples)

a. Inspection Scope

The inspectors determined that there have been four declared pregnant workers during the current assessment period. The inspectors reviewed the exposure results and monitoring controls employed by PSEG with respect to requirements of 10 CFR 20.

The inspectors reviewed PSEG's self assessments, audits, and Special Reports related to the ALARA program since the last inspection. The inspectors determined that PSEG's overall audit program's scope and frequency (for all applicable areas under the Occupational Radiation Safety Cornerstone) met the requirements of 10 CFR 20.1101(c).

The inspectors evaluated PSEG performance against the requirements contained in 10 CFR 20.1101.

b. Findings

No findings of significance were identified.

2OS3 Radiation Monitoring Instrumentation and Protective Equipment (71121.03 - 4 samples)

a. Inspection Scope

The inspectors verified the calibration, operability, and alarm setpoints of several types of instruments and equipment. Verification methods included: review of calibration documentation, observation of PSEG source check or calibrator exposed readings, or comparison of source readings using an NRC survey instrument. The inspectors reviewed the detector measurement geometry, calibration method and appropriate selection of calibration sources to closely represent the actual measurement conditions in the plant. The inspectors observed electronic and radiation calibration of these instruments. The inspectors reviewed the alarm set point determinations and observed in-field source checks. The inspectors reviewed the actions that were taken when an instrument was found significantly out of calibration (>50%) during calibration or source checks. The inspectors determined the possible consequences of instrument use since the last successful calibration or source check. The inspectors verified that the out of calibration results were entered into the corrective action program.

For repetitive deficiencies or significant individual deficiencies in problem identification and resolution identified above, the inspectors determined that PSEG's self-assessment activities were also identifying and addressing these deficiencies.

The inspectors verified that the calibration expiration and source response checks were current on radiation detection instruments staged for use. The inspectors observed radiation protection technicians for appropriate instrument selection and self-verification of instrument operability prior to use.

Based on FSAR, Technical Specifications and Emergency Operating Procedures requirements, the inspectors reviewed the status and surveillance records of self contained breathing apparatus (SCBA) staged and ready for use in the plant. The inspectors reviewed PSEG's capability for refilling and transporting SCBA air bottles to and from the control room and operations support center during emergency conditions. The inspectors determined that control room operators and other emergency response and radiation protection personnel were trained and qualified in the use of SCBA (including personal bottle change-out). The inspectors determined that personnel assigned to refill bottles were trained and qualified for that task.

The inspectors evaluated PSEG performance against the requirements contained in 10 CFR 20.1501, 10 CFR 20.1703,10 CFR 20.1704, ANSI N323-1978, ANSI N323A-1997 and ANSI N42.17A-2004.

b. Findings

No findings of significance were identified.

4. OTHER ACTIVITIES

4OA1 Performance Indicator (PI) Verification (71151 – 6 samples)

a. Inspection Scope

The inspectors reviewed PSEG submittals for the Unit 1 and Unit 2 initiating events cornerstone performance indicators discussed below. To verify the accuracy of the PI data reported during this period the data was compared to the PI definition and guidance contained in Nuclear Energy Institute (NEI) 99-02, "Regulatory Assessment Performance Indicator Guideline," Revision 5.

Cornerstone: Initiating Events

- Unit 1 and Unit 2 unplanned scrams
- Unit 1 and Unit 2 unplanned scrams with complications
- Unit 1 and Unit 2 unplanned power changes

b. Findings

No findings of significance were identified.

4OA2 Identification and Resolution of Problems (71152 - 4 samples)

.1 Review of Items Entered into the Corrective Action Program:

As required by Inspection Procedure 71152, “Identification and Resolution of Problems,” and in order to help identify repetitive equipment failures or specific human performance issues for follow-up, the inspectors performed a daily screening of all items entered into PSEG's corrective action program. This was accomplished by reviewing the description of each new notification and attending daily management review committee meetings. Documents reviewed are listed in the Attachment.

.2 Semi-Annual Review to Identify Trends

a. Inspection Scope

As required by Inspection Procedure 71152, “Identification and Resolution of Problems,” the inspectors performed a review of PSEG’s corrective action program (CAP) and associated documents to identify trends that could indicate the existence of a more significant safety issue. The inspectors’ review was focused on repetitive equipment and corrective maintenance issues, but also considered the results of daily inspector CAP item screening discussed in Section 4OA2.1. The review included issues documented in system health reports, corrective maintenance WOs, component status reports, site monthly meeting reports and maintenance rule assessments. The inspectors’ review nominally considered the six-month period of December 1, 2008 through May 31, 2009, although some examples expanded beyond those dates when the scope of the trend warranted. The inspectors compared and contrasted their results with the results contained in PSEG’s latest integrated quarterly assessment report. Corrective actions associated with a sample of the issues identified in PSEG’s trend report were reviewed for adequacy. Specific documents reviewed are listed in the Attachment.

The reactor oversight process (ROP) defines a cross cutting theme as four or more inspection findings that are assigned the same cross cutting aspect. During this assessment period, the theme level has been reached, with four findings in human performance with a procedure compliance cross cutting aspect. Two of the four findings were in the physical security cornerstone, one of the findings was in the initiating events cornerstone, and one of the findings was in the mitigating systems cornerstone. The threshold for a procedure compliance cross cutting theme was reached in May 2009.

The procedure compliance theme (H.4.b) is not a new theme for PSEG at Salem. There have been findings to support a theme at five consecutive ROP cycle reviews, starting at the end of 2005. A substantive cross-cutting issue (SCCI) in procedure compliance was opened at the 2007 mid-cycle assessment, with six findings and the fourth consecutive time that the theme was met. The SCCI was cleared at the 2008 mid-cycle assessment, when the number of procedure compliance findings had dropped to two, and corrective actions from PSEG’s root cause investigation had been completed.

The inspectors performed a problem identification and resolution semi-annual trend inspection to review the results of the human performance cross-cutting theme identified in procedure use and compliance.

b. Assessment and Observations

No findings of significance were identified. The inspectors noted a trend of low level issues entered into the CAP related to equipment reliability issues. There have been failures or degradation of several safety related service water valves during this period. PSEG has a design change prepared to replace the chiller service water flow control valves with a better design for throttling service. The component cooling water system and containment cooling systems were also affected by service water valve failures. The inspectors determined that PSEG is aware of these areas identified through this trend review and is appropriately addressing these issues.

A cross-cutting theme in human performance with a cross-cutting aspect in procedure compliance was reached by PSEG at Salem in May 2009. PSEG plans to conduct an additional evaluation of the current theme to supplement the numerous corrective actions existing in excellence plans for 2009. Corrective actions for the 2007 SCCI in procedure compliance focused on improvement in compliance with continuous use (level 1) and reference use (level 2) procedures. Those procedures were required to be at the job site, and required initialing of steps in the procedure when the procedure step was completed. The manager in the field program and the dynamic learning activities completed by each department focused on step by step completion of each procedure as written, and stopping for supervisory guidance when the procedure could not be performed as written. Corrective actions based on the 2007 procedure compliance SCCI have been effective in reducing the number of procedure compliance issues with level 1 and level 2 procedures. None of the four procedure compliance findings for this evaluation cycle are related to a level 1 or a level 2 procedure. They are all related to compliance with information use (level 3) procedures. PSEG recognizes that human performance standards must be raised in order to ensure compliance with all procedures, not just those carried in hand at the job site or used in the control room.

PSEG developed excellence plans and performed several evaluations over the past year that specify corrective actions for procedure adequacy and procedure compliance issues. These plans and evaluations are discussed in more detail in the PIR annual sample on human performance, procedure and document quality (Section 4OA2.5). The following discussion is limited to procedure use and adherence, with a focus on level 3, information use or administrative procedures.

Work Group Evaluation: An evaluation on *administrative procedure quality* was performed in May 2009. This work group evaluation includes corrective actions to perform administrative procedure reviews and cross-functional area procedure reviews, with the intent of improving familiarity and compliance with administrative procedures.

Common Cause Evaluation: An evaluation of all the *upper tier causal analyses* was performed in February 2009. The corrective actions included periodic familiarization and refresher reviews were required for applicable administrative procedures. Proficiency with key discipline procedures were incorporated into individual development plans.

Common Cause Evaluation: An evaluation on *technical rigor and technical human performance* was conducted in January, 2009, by the engineering department. Engineering department corrective actions were assigned to improve procedure compliance, based on this analysis. Two corrective actions specified were to perform an interactive training evaluation for procedure use and adherence, and to develop a dynamic learning activity for field walk downs.

Root Cause Evaluation: An evaluation was completed for the *unintended reduction in reactor coolant system inventory* in November 2008. One of the corrective actions specified in this evaluation was to implement actions to address weaknesses in the use of operator fundamentals using the simulator training environment. Another corrective action specified was to develop and implement a strategy for raising the level of awareness and familiarization of administrative processes and procedures. This included departmental training on specific administrative procedures that are important because of the impact that they have on implementing procedures.

Common Cause Analysis: A cause analysis was performed to address a *security department human performance adverse trend.* Procedure compliance was found to be the top causal factor for this adverse trend. The security excellence plan has actions to address this issue, including the following examples. A monthly proficiency challenge on security procedures requires security officers to become more familiar with the procedures, as procedure specific questions must be answered. A similar procedure review is conducted weekly between the supervisor and each security officer, with the security officer referring to a specific procedure to communicate the correct response to his or her supervisor. In addition, PSEG has added a PSEG security supervisor on shift for continuous site coverage for the purpose of raising human performance standards and providing additional oversight.

Root Cause Evaluation: An evaluation was completed in August of 2008 for a *technical specification 3.0.3 required shutdown due to a non–conservative steam flow set point*. One of the contributing causes to this event was that procedure use and adherence was less than adequate. Corrective actions specified were to conduct training to address use of the change management procedure, approval signatures for procedures that are identified as important plant activities, and accounting for test procedure prerequisites when scheduling procedures.

Following the 2007 SCCI in procedure compliance, the inspectors concluded that corrective actions taken were comprehensive, timely, and effective in reducing non-compliance issues with continuous use (level 1) and reference use (level 2) procedures. A performance gap continues to exist in compliance with information use (level 3) procedures. This has led to the number of findings reaching the theme level in procedure compliance for the 2009 mid-cycle evaluation.

Performance gaps in procedure compliance with administrative procedures are being addressed through departmental excellence plans, evaluations, and associated corrective actions. The corrective actions being taken by PSEG are comprehensive

and timely. Effectiveness of the corrective actions to close these performance gaps are being evaluated as the corrective actions are completed.

The inspectors also concluded that the station has made progress in improving procedure compliance through corrective actions. For example, one measure of procedure compliance at Salem is reflected by the performance indicators used as part of the ROP. These statistics reflect an improving trend in several of the performance indicators for the previous twelve months. Specifically, there have been no unplanned scrams at either unit, and only one unplanned downpower per unit in the last year. There have been no Safety system functional failures, and no emergency AC power test failures over the past year. There have been no required LER submittals by the station in 2009. These indicators support an improving trend in procedure compliance at Salem generating station.

.3 Annual Sample: Pressurizer Power-Operated Relief and Spray Valve Challenges

a. Inspection Scope

This inspection focused on PSEG's identification, evaluation, and resolution of challenges associated with the pressurizer power-operated relief valves (PORV) and pressurizer spray valves. Specifically, seat leakage had been experienced with the PORV and spray valves; and the stroke length of the spray valves was shorter than expected.

The inspectors reviewed PSEG's associated technical evaluations and corrective action reports. The inspectors interviewed plant personnel, and reviewed performance data (such as leak rate history and trending data), operating and test procedures, and test results to evaluate the performance of the components and the effectiveness of PSEG's corrective actions. In addition, the inspectors toured the Unit 1 and Unit 2 control rooms and reviewed the Salem Technical Specifications and Updated Final Safety Analysis Report to assess the potential adverse impact of leakage and the associated configuration on plant operations. Documents reviewed are listed in the Attachment.

b. Findings and Observations

No findings of significance were identified.

The inspectors noted that the operational challenges associated with the pressurizer were more severe at Unit 2. Specifically, one of the two PORVs and one of the two spray valves were isolated due to excessive valve seat leakage. PSEG appropriately evaluated the issues, both individually and collectively; and the potential risks of the proposed corrective action options (i.e., repairing components, monitoring leakage, performing additional online troubleshooting, etc.) were properly considered. PSEG's evaluation also considered existing pressurizer heater issues in assessing the collective impact of the pressurizer challenges to equipment and plant operators. The inspectors confirmed that PSEG was adequately monitoring and trending relevant pressurizer parameters so that worsening conditions could be identified and addressed in a timely fashion. PSEG developed a contingency maintenance outage plan to repair the valves in the event the monitored leakage becomes excessive, and plans on repairing the

degraded components during the next refueling outage if the monitored leakage remains at an acceptable level. The inspectors found that PSEG's actions to evaluate and correct the PORV and spray valve challenges were appropriate.

.4 Annual Sample: Service Water Valve Margin Review

a. Inspection Scope

This inspection focused on the design margin associated with selected service water (SW) system air-operated valves (AOV) and motor-operated valves (MOV). In particular, this inspection was conducted after a recent discovery that valve design data incorrectly identified the maximum SW operating pressure at a value lower than the SW system could actually achieve under design conditions for SW system valve 22SW127 (component cooling water system heat exchanger service water outlet control valve). This inspection reviewed PSEG's identification, evaluation, and resolution of similar deficiencies for additional SW AOVs and MOVs.

The inspectors reviewed PSEG's associated technical evaluations and corrective action reports. The inspectors also interviewed plant personnel and reviewed design and operating requirements associated with the SW system to determine whether the appropriate design and operating limits were appropriately considered and evaluated, and that the subject valves could function under design conditions. Documents reviewed are listed in the Attachment.

b. Findings and Observations

No findings of significance were identified.

During the conduct of this review, it was observed that some of the design documents contained incorrect and non-conservative values for the SW pressure. In particular, some of the design documents indicated that the pressure was 130 psig. While this is accurate for normal operating conditions, the SW operating procedures allowed system operation to be as high as 150 psig; and, under certain postulated scenarios, SW system pressure could reach as high as 179 psig. Notwithstanding this discrepancy between the operating and design value for SW system pressure, PSEG demonstrated, and the inspectors confirmed, that the AOVs and MOVs were capable of operating at the higher SW system pressure of 179 psig by reviewing the specific design documents and AOV and MOV procurement specifications. PSEG's ongoing actions included ensuring the design documentation for the affected SW system valves were consistent and accurate with regard to the operating and design values for SW system pressure. The cause of this issue was attributed to a design control weakness, as documented in NRC Inspection Report 05000272 & 311/2008005. PSEG's extent-of-condition review did not identify similar concerns with other systems, and corrective actions taken to date have been appropriate.

.5 Annual Sample: Human Performance, Procedure and Document Quality

a. Inspection Scope

The inspectors reviewed the actions PSEG had taken to improve procedure and document quality at the station. This sample evaluated PSEG's scope of efforts and progress in the area of procedure and document quality for the period of January 2009 through June 2009.

b. Findings and Observations

No findings of significance were identified.

On March 4, 2009, the NRC identified a substantive cross-cutting issue in the area of human performance with a cross-cutting theme in the aspect of document and procedure adequacy. In response, the PSEG Chief Nuclear Officer issued a communication to station personnel requesting their support and attention in resolving a performance problem in document and procedure adequacy. PSEG established a procedure adequacy excellence plan in an effort to resolve this issue. In addition, all departments had excellence plans in place to improve human performance. PSEG personnel also performed three common cause analyses, two work group evaluations, and a root cause analysis that were directly related to procedure and document adequacy. These evaluations included:

Common Cause Analysis: On January 12, 2009, PSEG completed an analysis to address the trend in *technical rigor and technical human performance*, focused on the engineering department. The primary causes associated with these technical performance issues were attention to detail, validation, procedure use and adherence, legacy latent errors, and field walk down validation quality. Several corrective actions are in progress or have been completed to address these causes, including the development of templates for corrective action evaluation products and modification acceptance testing preparation. The engineering excellence plan contains several actions that have been completed to improve the level of technical rigor within the department. For example, test review boards have been implemented for all critical tests to ensure that the test criteria are well defined. The engineering review board scores all engineering work products for tracking and provides feedback to the manager for coaching and documentation. A training needs analysis was completed to identify work group specific training. The training needs identified included apparent cause evaluation, systems, and test engineering. Equipment specific troubleshooting charts were generated to enhance the complex troubleshooting process. A central file was compiled with completed complex troubleshooters, and engineering staff was trained on existing resources.

Common Cause Analysis: A cause analysis was performed to address a *security department human performance adverse trend.* Procedure quality and procedure compliance were found to be the top two causal factors for this adverse trend. The security excellence plan provides action to address these issues, including a monthly written proficiency test on security procedures. This requires security officers to become more familiar with the procedures, as procedure specific questions must be answered. A similar procedure review is conducted weekly between the supervisor and each security officer, with the security officer referring to a specific procedure to communicate the correct response to his or her supervisor. A procedure review is in progress to

upgrade the security procedures to ensure that they are suitable for regulatory compliance and are written for ease of use.

Common Cause Analysis: On February 4, 2009, PSEG completed an analysis that reviewed all 2008 *upper tier causal analyses, and all 2008 NRC findings for common trends in causal factors*. Procedure and document quality was seen as the dominant cause for the 2008 NRC findings and class A, B, and C, evaluations. The evaluation concluded that procedure and document quality issues are occurring at a higher rate than procedure use and adherence issues. Procedure and document quality issues are the major causal factor in all categories except implementing administrative procedures. Additionally, most issues originate from the maintenance and engineering program areas, specifically related to PM program implementing document quality, work order quality, design change package quality, and test plan quality. These issues are broadly addressed in the in the procedure quality excellence plan, and specifically addressed by actions contained in the maintenance and engineering department excellence plans. Corrective actions were taken by maintenance department to improve the preventive maintenance program implementing document quality and work order quality. Specifically, a preventive maintenance oversight committee was established to independently challenge each of the Performance Centered Maintenance (PCM) templates as they are completed to ensure that the proper scope and frequency is determined. The PCM template reviews of the most critical components are scheduled for completions by August 27, 2009. The final implementation of all PCM templates is scheduled for completion by March 30, 2010. Quality review boards have been established to review selected work packages on a monthly basis. The review board consists of members from the maintenance shops as well as planners to ensure critical feedback.

Work Group Evaluation: An evaluation on *administrative procedure quality* was completed on May 6, 2009. Based on a review of the events related to administrative procedures, inadequate use or knowledge of the administrative procedures was the dominant cause of the events rather than administrative procedure quality. These knowledge gaps are being addressed through departmental procedure reviews and departmental specific training. In addition to the departmental actions, a weekly site wide administrative procedure review and communication plan was implemented. Each department provided a prioritized list of administrative procedures that contain key roles and responsibilities for other station departments. A single page summary of the procedure which identified key points was used for site wide communication. Although it was not found to be the dominant cause, corrective actions were specified to improve procedure quality, which included the performance of a functional area administrative procedure review plan, in addition to the development and implementation of a cross-functional area administrative procedure review plan. A graded approach to identify and review the procedures with the highest risk potential first is a key part of the plan.

Work Group Evaluation: An evaluation on *work package quality* was completed on May 6, 2009. The cause of less than adequate quality of some work packages was insufficient organizational focus on continuously improving work package quality over a sustained period of time. Feedback from the work groups performing the work packages is important to improving work package quality. The quantity of feedback forms submitted was good in 2009, with 9,267 feedback forms generated for 16,251 work

orders generated in 2008. However, the quality of the feedback was found to be non-uniform among work groups, and the level of detail provided in some of the feedback was inadequate. Departmental training is being rolled out to maintenance shops to raise the quality of feedback being submitted associated with work order completion. Corrective actions listed in this evaluation were to attend the EPRI work planning users group and apply lessons learned to improve work package quality. Additionally, Hope Creek's quality review team has been tasked to evaluate work package quality at Salem.

Root Cause Evaluation: On June 22, 2009, PSEG completed an evaluation on *implementing procedure quality*. This document investigated and determined causes that require corrective action by PSEG to improve procedure quality. The root cause evaluation confirmed that many significant issues were a result of inadequate procedure quality. An example of this was the procedure that was used to limit circulating water total residual chlorine level. This implementing procedure was a contributing cause in the excessive residual chlorine levels, because of an excessive number of references and single procedure steps which required multiple actions to be taken. PSEG determined that the root cause was that management failed to enforce administrative processes, specifically with regard to rigorous reviews, validation and incorporation of operating experience to ensure implementing procedure quality.

The process for implementing procedure development and revision includes four elements that are designed to ensure procedure quality. The root cause evaluation found that these elements are either inconsistently used or not used at all.

- HU-AA-1212 risk assessments and pre-job briefs are not routinely used to improve implementing procedure quality.
- Validation techniques are not routinely used to improve procedure quality, even in some instances where validation is clearly required, such as a new procedure or a totally new section in a procedure.
- Cross discipline reviews are not routinely used to improve procedure quality.
- The station qualified reviewer (SQR) process is routinely used; however, it is not always effective. In some instances, such as a new procedure or an extensive revision, an SQR was appropriate but was not performed.

Contributing to the root cause was a lack of sensitivity regarding the content and volume of the procedure backlog, which has resulted in the inadequate assessment of risk significance and ineffective prioritization and failure to allocate the appropriate resources to identify and correct long standing procedure deficiencies. Recently, maintenance department assigned two full time procedure writers to reduce the backlog of procedures in need of revision. Additionally, the station has not implemented industry best practices to ensure the quality of implementing procedures.

As a result of the root cause evaluation, PSEG initiated fifteen corrective actions, including two corrective actions tailored to prevent recurrence. These corrective actions are in progress and address the root and contributing causes. Procedure AD-AA-102, Station Qualified Review, is being revised to add a mandatory checklist with signatures required by the reviewer and the approver for implementing procedures. Cross discipline reviews for implementing procedures, validation checklists, and documentation of review of existing operating experience are being implemented to make the procedure

creation and revision process more rigorous and facilitate improvements in implementing procedure quality. PSEG procedure HU-AA-104-101, Procedure Use and Adherence, is being revised to include industry best practices to identify and enhance performance of critical steps in a procedure. Operations department was tasked with the revision of three specific operations procedures found to be deficient by the root cause team. The operator experience coordinator has been assigned to develop and implement an operating experience recovery plan to communicate and inform station personnel on the operating experience process, and to evaluate and incorporate improvements in to the appropriate station documents. A lead responsible engineer is being assigned to perform a cross discipline review when changes are incorporated into a procedure during a design change project. These corrective actions are expected to be completed by the end of 2009.

Inspector Observations: The number of significant document and procedure quality issues at Salem has decreased over the past six months. The root cause evaluation and three common causes addressing this issue determined several causal factors for this issue. Corrective actions have been assigned to address these causal factors, all targeted to improve procedure and document quality at PSEG. The effectiveness of these assigned corrective actions will be evaluated following their completion.

The inspectors assessed progress of corrective actions to improve procedure compliance and procedure quality. The inspectors have seen notifications requesting enhancements and improvements to administrative and implementing procedures on a daily basis. The backlog of these procedure revision requests has begun to be worked down by the responsible departments, and is reviewed by the site leadership team on a weekly basis. Salem maintenance department now has two full time procedure writers dedicated to revising and improving the existing maintenance department procedures. Another measure of procedure compliance and procedure quality at Salem is reflected by the performance indicators used as part of the ROP. These numbers reflect an improving trend in several of the performance indicators for the previous twelve months. Specifically, there have been no unplanned scrams at either unit, and only one unplanned downpower per unit in the last year. There have been no Safety system functional failures, and no emergency AC power test failures over the past year. There have been no required LER submittals by the station in 2009. These indicators support overall improvements in human performance at Salem generating station.

The inspectors also reviewed the trend in procedure compliance and procedure quality findings in aggregate over the assessment period. During the first six months of the assessment period, there were eight findings with cross cutting aspects in procedure compliance and procedure quality. During the second half of the assessment period, there were three findings with cross cutting aspects in procedure compliance and procedure quality. The inspectors concluded that corrective actions for procedure compliance and procedure quality are having a positive impact on station performance, and the reduction in the number of findings with crosscutting aspects in these selected areas.

4OA5 Other Activities

.1 Quarterly Resident Inspector Observations of Security Personnel and Activities

a. Inspection Scope

During the inspection period, the inspectors conducted observations of security force personnel and activities to ensure that the activities were consistent with PSEG security procedures and regulatory requirements related to nuclear plant security. These observations took place during both normal and off-normal plant working hours. These quarterly resident inspector observations of security force personnel and activities did not constitute any additional inspection samples. Rather, they were considered an integral part of the inspectors' normal plant status review and inspection activities.

b. Findings

No findings of significance were identified.

.2 Radwaste Shipment

a. Inspection Scope

The inspectors reviewed the circumstances surrounding PSEG's shipment of a liner (shipment 09-19) of dewatered resin to Energy*Solutions*™ Barnwell Low-Level Disposal Facility on March 18, 2009. Upon arrival at the Barnwell facility, the liner was examined by the State of South Carolina and determined to have free-standing, non-corrosive liquid in excess of that permitted under Title 10, Code of Federal Regulations, Part 61.56(a)(3) and Condition 32.C of South Carolina Radioactive Material License 097 (for the operation of the Barnwell Facility).

As a result of this event, the State of South Carolina entered into a Consent Order with PSEG (Order 09-02-RW, dated April 22, 2009), which resulted in PSEG having its burial site access at the Barnwell Facility suspended for thirty days. PSEG initiated Notification 20406371 to document this event, determine cause, and specify actions to prevent recurrence.

The inspectors determined from records for the handling and processing of this shipment (Duratek Salem Waste Processing Report, Vessel Size/Type PL-14-215FR, Vessel Serial No. L506857-8) that the resin was properly dewatered in November 2006, and appropriately stored until March 2009; and all criteria specified in the procedure were effectively met. In accordance with Section 3.1.11.2 of Energy*Solutions*™ procedure FO-AD-002 (Operating Guidelines for Polyethylene HICs), "…a HIC can be stored for an indefinite period of time and then shipped, meeting the current disposal criteria...," when it has been properly processed.

The inspectors confirmed that PSEG properly processed the liner prior to shipment by meeting all of the applicable standards and requirements specified in the approved procedure; and therefore had a reasonable expectation that HIC's processed in this manner would meet the current disposal criteria. Accordingly, though the HIC liner was subsequently found to contain free-standing water in excess of the disposal site burial criteria, the condition was not as a result of PSEG failing to meet a requirement or standard where the cause was reasonably within PSEG's ability to foresee and correct; and therefore did not constitute a performance deficiency.

b. Findings

No findings of significance were identified.

4OA6 Meetings, Including Exit

On July 9, 2009, the resident inspectors presented the inspection results to Mr. Eilola. PSEG acknowledged that none of the information reviewed by the inspectors was proprietary.

ATTACHMENT: SUPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee personnel:

H. Berrick, Regulatory Affairs
S. Crampton, System Engineer
A. Garcia, System Engineer
R. Gary, Radiation Protection Manager
G. Gellrich, Plant Manager
D. Johnson, MOV Program Engineer
D. Kolasinski, System Engineer
T. Neufang, Radiological Engineering Manager
L. Oberembt, NSSS Branch Manager
F. Szanyi, AOV Program Engineer
B. Thomas, Licensing Engineer

LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

None

Opened/Closed

05000311/2009003-001	NCV	Improper Maintenance Rule Scoping of the SWIS Sump System (Section 1R12)
05000272/2009003-002	FIN	Inadequate Maintenance of the 13 AFW Pump Governor (Section 1R15)

Discussed

None

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
S1.OP-AB.GRID-0001, Abnormal Grid, Rev. 18
OP-AA-108-111, Elevated DGA data for #2 APT LTC-B, Rev. 4

OP-AA-108-111, #1 APT, Cooling Group 1 Breaker 8-1 Hotspot, Rev. 3
OP-AA-108-107-1001, Electric System Emergency Operations and Electric Systems Operator Interface, Rev. 3

Notifications
20398679 20410988 20415953 20406397

Orders
60081184 60082875

Other Documents
2009 Salem Stations Summer Readiness
Summer 2009 Transformer Readiness
WC-AA-107, Seasonal Readiness, Rev. 8

Section 1R04: Equipment Alignment

Procedures
S1.OP-SO.CVC-0001, Revision 32, Charging, Letdown, and Seal Injection
S1.OP-SO.CVC-0002, Revision 35, Charging Pump Operation
S1.OP-SO.CVC-0006, Revision 20, Boron Concentration Control
S1.OP-SO.CVC-0008, Revision 8, Rapid Boration
S1.OP-ST.28-0001, Electrical Power Systems 28VDC Distribution, Rev. 4

Drawings
205228

Notifications
20229577 20286885 20335549 20379514 20398811 20403131
20406205 20409325 20414336 20413225

Orders
60074893

Other Documents
WCD 42476888, 11 Safety Injection Pump Discharge Check Valve;

Section 1R05: Fire Protection

Procedures
FRS-II-411, Reactor Plant Auxiliary Equipment Area Elevations: 45’ & 55’, Rev. 2
FRS-II-611, Reactor Containment Elevations: 78’, 100’ & 130’, Rev. 5
FRS-II-512, Mechanical Piping Penetration Area Elevations: 78’ & 100’, Rev. 2
FRS-II-424, CVCS Hold-up Tank Area, Elevation 64’, Rev. 2
FRS-II-454, Volume Control and Boric Acid Tanks Auxiliary Building Elevation 122' - 0"

Notifications
20408309

Section 1R06: Flood Protection Measures

Procedures
SC.OP-DL.ZZ-0008, Circulating/Service Water Log, Rev. 23
SC.OP-DL.ZZ-0008, Circulating/Service Water Log, Rev. 23
S2.OP-AB.SW-0003, Service Water Bay Leak, Rev. 7
S2.OP-AB.ZZ-0002, Flooding, Rev. 3
S2.OP-AB.SW-0001, Loss of Service Water Header Pressure, Rev. 16
SW.OP-SO.SW-0005, Service Water System Operation, Rev. 40
2-EOP-LOPA-1, Loss of All AC Power, Rev. 26
SC.OP-SO.ZZ-0003, Component Biofouling, Rev. 7

Drawings

223662	205342	223127	231004	620530	220927
205323	205339	203063	222475	222476	601401

Notifications

20409612	20409613	20416468	20074845	20328697	20416468
20410390	20410653	20411444	20334971	20387026	20409798
20409801	20410166	20410333	20309739	20411266	20385857
20415904	20416832	20416833			

Orders

70097216	70096868	60082565	70097216	30103882	70073608
70090401	70073608				

Other Documents
SAEP 2009-04, Salem Maintenance Rule Expert Panel Minutes, May 14, 2009
VTD 311648, Magnetrol International Instruction Manual for Models T20 and T21 Series Liequid Level Controls, Rev. 2
Salem Additional Reading/Operator Action Log, CW/SW Operator Additional Reading Sheet

Section 1R07: Heat Sink Performance

Procedures
S1.OP-PM-CC-0012, 12 Component Cooling Heat Exchanger High Flow Flush and Alignment, Rev. 19

Notifications
20413395

Orders
30177775

Other Documents

Section 1R11: Licensed Operator Requalification Program

Procedures
NC.EP-EP-0102, Emergency Coordinator Response, Rev. 14
S2.OP-SW.SWV-0001, Service Water Ventilation Operation, Rev. 3
S2.OP-AB.SW-0005, Loss of All Service Water, Rev. 4
1-EOP-TRIP-1, Reactor Trip or Safety Injection, Rev. 26
2-EOP-LOPA-1, Loss of All AC Power, Rev. 26

Notifications
20413129 20413130 20412165

Other Documents
ESG-0902D, Simulator Training Scenario, Segment 2 OBE "Delta Shift", Rev. 0

Section 1R12: Maintenance Effectiveness

Procedures
SC.OP-DL.ZZ-0008, Circulating/Service Water Log, Rev. 23
SC.OP-DL.ZZ-0008, Circulating/Service Water Log, Rev. 23
MA-AA-716-210, Performance Centered Maintenance (PCM) Process, Rev. 5
ER-AA-310, Implementation of the Maintenance Rule, Rev. 6
ER-AA-310-1001, Maintenance Rule – Scoping, Rev. 3
ER-AA-310-1002, Maintenance Rule – SSC Risk Significance Determination, Rev. 2
ER-AA-310-1003, Maintenance Rule – Performance Criteria Selection, Rev. 3
ER-AA-310-1004, Maintenance Rule – Performance Monitoring, Rev. 7
ER-AA-310-1005, Maintenance Rule - Dispositioning Between (a)(1) and (a)(2), Rev. 5
S2.OP-AB.SW-0003, Service Water Bay Leak, Rev. 7
S2.OP-AB.ZZ-0002, Flooding, Rev. 3
S2.OP-AB.SW-0001, Loss of Service Water Header Pressure, Rev. 16
SW.OP-SO.SW-0005, Service Water System Operation, Rev. 40
2-EOP-LOPA-1, Loss of All AC Power, Rev. 26
SC.OP-SO.ZZ-0003, Component Biofouling, Rev. 7

Drawings

223662	205342	223127	231004	620530	220927
205323	205339	203063	222475	222476	601401

Notifications

20147408	20408862	20413137	20409577	20079218	20079287
20079218	20107229	20396664	20398412	20398822	20409103
20409612	20409613	20416468	20074845	20328697	20416468
20410390	20410653	20411444	20334971	20387026	20409798
20409801	20410166	20410333	20309739	20411266	20385857
20415904	20416832	20416833	20407238	20376685	

Orders

70097216	70096868	60082565	70097216	30103882	70073608
70090401	70073608	70079465	70064302	70087459	

Other Documents
SAEP 2009-04, Salem Maintenance Rule Expert Panel Minutes, May 14, 2009
VTD 311648, Magnetrol International Instruction Manual for Models T20 and T21 Series Liquid Level Controls, Rev. 2
Salem Additional Reading/Operator Action Log, CW/SW Operator Additional Reading Sheet

Section 1R13: Maintenance Risk Assessments and Emergent Work Control

Procedures
S1.OP-SO.SW-0005, Service Water System Operation, Rev. 40
S1.OP-AB.LOOP-0003, Partial Loss of Off-Site Power, Rev. 5
S2.OP-ST.PZR-0002, Inservice Testing PORV Block Valves Modes 1-6
HU-AA-104-101, Procedure Use and Adherence, Rev. 3

Drawings
203000 211042 211043 205342

Notifications
20419562 20419657 20419660 20420028 20420031 20419560
20419450 20409370 20409445

Orders
WCD 4248802 60083683 70096493

Other Documents
SGS Unit 1 PSA Risk Evaluation for Work Week 919 (5/03 to 5/09), Rev. 0
SGS Unit 1 PSA Risk Evaluation for Work Week 922 (5/24 to 5/30), Rev. 0
SGS Unit 2 PSA Risk Evaluation for Work Week 918 (4/26 to 5/2/09), Rev. 0
SGS Unit 2 PSA Risk Evaluation for Work Week 922 (5/24 to 5/30), Rev. 0
SGS Unit 2 PSA Risk Evaluation for Work Week 923 (5/31 to 6/06), Rev. 0

Section 1R15: Operability Evaluations

Procedures
OP-AA-108-115, Operability Determinations
S2.OP-SO.SW-0008, Revision 0, Inservice Room Cooler Flushes
S-C-ABV-NEE-0504, Revision 0, Effect of Inoperable Room Cooler on Vital Pump Operability
S-2-ABV-MDC-1821, Revision 1, Salem 2 Gothic ABV Model
S1.IC-CC.RCP-0066, 1PT-948A Containment Pressure Protection Channel IV, Rev. 9
S1.OP-ST.CVC-0010, Borated Water Sources, Rev. 8
S1.OP-SO.SJ-0002, Accumulator Operations, Rev. 18
S1.OP-SO.SJ-0003, RCS Pressure Isolation Valves Check Valve Reseating, Rev. 3
S1.OP-ST.SJ-0009, Emergency Core Cooling ECCS Subsystems – Tavg ≥ 350°F, Rev. 13
S1.OP-SO.RHR-0001, Initiating RHR, Rev. 27
1-EOP-TRIP-1, Reactor Trip or Safety Injection, Rev. 26
1-EOP-LOCA-1, Loss of Reactor Coolant, Rev. 25
1-EOP-LOCA-5, Loss of Emergency Recirculation, Rev. 24
1-EOP-LOCA-6, LOCA Outside Containment, Rev. 21
S1.OP-SO.SW-0005, Service Water System Operation, Rev. 40

S1.OP-AB.LOOP-0003, Partial Loss of Off-Site Power, Rev. 5
NC.ER-AP.ZZ-0010, Equipment Reliability Process, Rev. 1
MA-AA-716-210, Performance Centered Maintenance (PCM) Process, Rev. 5
WC-AA-111, Predefine Process, Revs 4 & 5
WC-AA-101-1003, Right Work Preparation Process, Rev. 3
ER-AA-10, Equipment Reliability Process Description, Rev. 1

Drawings

205342	207642	207533	610311	610314	226165
205250	205232	205234	205228	205201	205350
RH-1-1A	RH-1-1B	RH-1-1C	RH-1-3A	RH-1-3B	RH-1-3C
RH-1-3D	RH-1-3E	RH-1-3G	RH-1-3H	RH-1-3J	RH-2-3
RH-2-2	203000	211042	211043	205342	

Notifications

20412509	20414011	20417556	20416757	20419536	20411031
20411300	20411294	20408074	20408241	20409032	20409145
20409991	20410966	20411086	20411168	20411586	20411572
20412137	20419553	20418139	20421042	20413755	20416439
20409415	20383921	20419562	20419657	20419660	20420028
20420031	20419560	20419450	20416991	20410180	20410175
20410172	20409613	20409612	20387026	20373623	20248823
20400868	20259635	20365475	20401620	20349198	20183687
20401157					

Orders

70097660	50118167	60083923	70098782	50111121	50090862
50104819	70096971	70096846	70096422	70089340	70094138
70017180	70078664	70037915	80054181	80044406	

Other Documents
VTD 301129, Rosemount Nuclear Model 1159 Remote Diaphragm Seals Manual
SC-CS002-01, Salem Unit 1, 2 Containment Pressure, Rev. 4
CC-AA-309-101, Air-Entrained Water Observed While Venting 1SJ170 - 20409145, Rev. 9
CC-AA-309-101, Gas Voiding Issues Associated with 11 RHR Water Hammer - 20408241 and Lowering 14 Accumulator - 20408074, Rev. 9
CC-AA-309-101, Gas Voiding Issues Associated with 11 RHR Water Hammer - Troubleshooter Results - 20409991, Rev. 9
Root Cause Evaluation: 13 AFP Tripped Due to Erratic Indication
Salem Issue Summary: Speed Oscillations on the 13 AFW Pump Result in Manually Tripping the 13 AFW Pump During a Routine Surveillance Test (Inspection Report 2009-03)
Salem Issue Summary: Incorrect Initial Risk Assessment for the 13 AFW Pump Emergeny Unavailability (Inspection Report 2009-02)

Section 1R18: Plant Modifications

Procedures
CC-AA-112-1001, Provide Temporary Power to Panels SPDSA1 & SPDSA2, Rev. 1
CC-AA-102, Design Input and Configuration Change Impact Screening, Rev. 15

Orders
80091021

Other Documents
T-Mod 1ST09-005/S2-2009-083, Rev. 0

Section 1R19: Post-Maintenance Testing

Procedures
S2.OP-ST.SW-0009, Inservice Testing Service Water Valves (Penetration Area) Modes 1-2, Rev. 9
SC.MD-PM.CH-0002, Chiller Condenser Heat Exchanger Internal Inspection and Leak Check, Rev. 11
SC.MD-PM.ZZ-0052, Disassembly, Inspection and Reassembly of Velan Swing Check Valves Mark #s A-160, A-165, A-224, AA-64, AA-121, AA-122, AA-153, E-6, EA-8, FA-33, FA-34, and Valves 1(2)CV463, Rev. 6
S1.OP-ST.SJ-0002, Inservice Testing – 12 Safety Injection Pump, Rev. 16
S1.OP-SO.28-0001, 1A 28VDC Battery Charger Operation, Rev. 7
S1.OP-SO.28-0004, 1A 28VDC Bus Operation, Rev. 11
SC.MD-ST.28D-0001, SC.MD-ST.28D-0001, Preventive Maintenance and 18 Month Surveillance of 28 Volt Station Battery Chargers, Rev. 15
SC.MD-CM-ABV-0001, Auxiliary Building Supply and Exhaust Fan Repairs, Rev. 8
NC.NA-AP.ZZ-0050, Station Post Maintenance Testing, Rev. 7
MA-AA-716-012, Post Maintenance Testing, Rev. 13
S2.OP-ST.CH-0004, Chilled Water System – Chillers, Rev. 16
SC.MD-PM.CH-0001, ACME Chiller Compressor Inspection and Repair, Rev. 14

Notifications

20413425	20411010	20411012	20411165	20413276	20417562
20409119	20411953	20411495			

Orders

30135572	30148346	30174772	30174807	60079153	70098389
60082743	50108975	60079598	70097058	60051502	30147773
30135707	60080587	60081865	60079002		

Section 1R22: Surveillance Testing

Procedures
S1.OP-ST.DG-0014, Revision 15, Diesel Generator Endurance Run
S1.OP-ST.DG-0021, Revision 7, Diesel Generator Hot Restart Test
S1.OP-ST.DG-0003, Revision 42, Diesel Generator Surveillance Test
S1.OP-SO.DG-0003, Revision 35, Diesel Generator Operation
S1.OP-ST.RHR-0001, Inservice Testing – 11 Residual Heat Removal Pump, Rev. 16
S1.OP-ST.AF-0003, Inservice Testing - 13 Auxiliary Feedwater Pump, Rev. 36
S1.RA-ST.RHR-0001, Inservice Testing 11 Residual Heat Removal Pump Acceptance Criteria, Rev. 7
S1.OP-ST.SSP-0010, Engineered Safety Features SSPS Slave Relays Test – Train “B”, Rev. 35
S1.OP-ST.SJ-0009, Emergency Core Cooling ECCS Subsystems – Tavg ≥ 350°F, Rev. 13

Drawings
205241 211317

Notifications
20414537 20408910 20408909 20408989

Orders
50121144 50110700

Section 1EP6: Drill Evaluation

Procedures
NC.EP-EP-0102, Emergency Coordinator Response, Rev. 14
S2.OP-SW.SWV-0001, Service Water Ventilation Operation, Rev. 3
S2.OP-AB.SW-0005, Loss of All Service Water, Rev. 4
1-EOP-TRIP-1, Reactor Trip or Safety Injection, Rev. 26
2-EOP-LOPA-1, Loss of All AC Power, Rev. 26
NC.EP-FT.ZZ-0006, Emergency Response Data System (ERDS) Test with NRC Salem Station, Rev. 6

Notifications
20413129 20413130 20412165 20419536 20410991

Other Documents
ESG-0902D, Simulator Training Scenario, Segment 2 OBE "Delta Shift", Rev. 0
Salem Event Classification Guides
SGS EAL/RAL Technical Basis, Salem Generating Station Emergency Action Level/Reporting Action Level Technical Basis Document, Revision 8
S09-01, Emergency Preparedness Training Drill Critique Report,

Section 2OS2: ALARA Planning and Controls

Other Documents
Salem Unit 1 19th Refueling Outage Radiological Performance Report

Section 4OA1: Performance Indicator Verification

Other Documents
Salem 1 1Q/2009 Performance Indicators
Salem 2 1Q/2009 Performance Indicators

Section 4OA2: Identification and Resolution of Problems

Procedures
S1.RA-ST.PZR-0003(Q), IST Pressurizer PORV & Spray and Reactor Head Vent Valves Acceptance Criteria, Rev. 4

Drawings

205242-A-8761, P&ID, Salem Unit 1 Service Water Nuclear Area, Sh. 1 – 7, Revs. 91,84,90,78,76,89,04

205342-A-8763, P&ID, Salem Unit 2 Service Water Nuclear Area, Sh. 1 – 7, Revs. 74,72,73,59,66,68,07

Notifications

20393829	20319802	20324591	20306817	20409621	20394420
20394884	20394390	20407517	20393429	20393680	20393712
20394272	20394563	20394608	20395475	20395527	20395645
20395792	20396003	20396203	20413395	20393704	20394581
20395276	20395872	20396179	20397067	20397636	20400868
20401134	20401148	20402011	20408238	20408862	20409621
20410483	20412964	20414068	20415659	20393892	20335119
20413417	20417379				

Orders

70068229	70064311	70092114	70037414	70093422	70092295
70097885	70073823	70097886	70097887		

Calculations/Evaluations

DCR 80090917, Re-Rate Service Water Components for Increased Pressure, Rev. 0

S-C-SW-MEE-1882, Salem SW Heat Exchangers – Suitability for Operation at Higher Pressures, Rev. 1

302-51616, Torque Calculations and Weak Link Analysis for 30-inch Tricentric Valves, Rev. 2

302-52777, Torque Calculations and Weak Link Analysis for 24-inch Tricentric Valves, Rev. 1

S-1-SW-MDC-0893, AC Motor Operated Butterfly Valve Calculation (11SW22), Sh. 9, Rev. 1

S-1-SW-MDC-0893, AC Motor Operated Butterfly Valve Calculation (12SW22), Sh. 10, Rev. 0

1SW26, AC Motor Operated Butterfly Valve Calculation (1SW26), Rev. 1

S-C-SW-NDC-2143, SW Diesel Generator Jacket Cooler Inlet, Rev. 1

Other Documents

OTDM No. 07-012, Salem Unit 1 Reactor Coolant System/Pressurizer Spray Valves 1PS1 and 1PS3 (S1RC – 1PS1/1PS3), 4/8/07

S1.OP-ST.PZR-0003(Q), IST Pressurizer PORV & Spray and Reactor Head Vent Valves, completed on 10/29/08

SC.IC-PM.RC-0002(Q), Pressurizer Spray Valve Operator Maintenance (S1RC-1PS1), completed on 10/31/05

SC.IC-PM.RC-0002(Q), Pressurizer Spray Valve Operator Maintenance (S1RC-1PS3), completed on 10/31/05

SC.IC-PM.RC-0002(Q), Pressurizer Spray Valve Operator Maintenance (S2RC-2PS1-AO), completed on 4/29/08

SC.IC-PM.RC-0002(Q), Pressurizer Spray Valve Operator Maintenance (S2RC-2PS1-AO), completed on 10/21/06

SC.IC-PM.RC-0002(Q), Pressurizer Spray Valve Operator Maintenance (S1RC-1PS1), completed on 10/30/02

SC.IC-PM.RC-0002(Q), Pressurizer Spray Valve Operator Maintenance (S2RC-2PS3-AO), completed on 0/21/06

SC.IC-PM.RC-0002(Q), Pressurizer Spray Valve Operator Maintenance (S1RC-1PS3-AO), completed on 11/17/08
SC.IC-PM.RC-0002(Q), Pressurizer Spray Valve Operator Maintenance (S1RC-1PS1-AO), completed on 11/17/08
SC.MD-CM.RC-0004(Q), PR1, PR2, and CV2 Valves Overhaul/Repacking (S1RC-1PR2), completed on 11/7/02
SC.MD-CM.RC-0004(Q), PR1, PR2, and CV2 Valves Overhaul/Repacking (S2RC-2PR1), completed on 417/05
SER OTDM No. S-08-009, Unit 2 Pressurizer PORVs, Pressurizer Spray Valves, Pressurizer Heaters, Rev. 1
LR-N05-0446, ASME Code Relief Request, Salem Units 1 and 2, 11/16/05
LR-N06-0134, ASME Code Relief Request Withdrawal, Salem Units 1 and 2, 4/12/06
AD-AA-101-1002, Rev. 11
AD-AA-101-1003, Implementing Procedure Writers Guide, Rev. 1
HU-AA-1211, Briefings - Pre-Job Heightened Level of Awareness, Infrequent Plant Activity and Post-Job Briefings, Rev. 6
HU-AA-1212, Technical Task Risk/Rigor Assessment, Pre-Job Brief, Independent Third Party Review, and Post-Job Brief, Rev. 3
Salem 1 Service Water Health Report, 4th Quarter 2008
Salem 2 Service Water Health Report, 4th Quarter 2008
Salem Units 1 and 2 Regulatory Assurance Weekly Report - 12/16/2008

Section 4OA3: Event Followup

Notifications
20417561 20417561

Section 4OA5: Other Activities

Procedures
EnergySolutions Procedure FO-AD-002, Rev 33, Operating Guidelines for Use of Polyethylene High Integrity Containers

Notifications
20406371

Other Documents
Duratek Salem Waste Processing Report, Vessel Size/Type PL-14-215FR, Vessel Serial No. L506857-8

LIST OF ACRONYMS

AFW	Auxiliary Feedwater
AOV	Air-operated Valve
CAP	Corrective Action Program
CVCS	Chemical and Volume Control System
ESOC	Electrical System Operations Center
FIN	Finding
MOV	Motor-operated Valve
NCV	Non-cited Violation
NRC	Nuclear Regulatory Commission
OSP	Offsite Power
PARS	Publicly Available Records
PCM	Performance Centered Maintenance
PI	Performance Indicator
PM	Preventive Maintenance
PORV	Power-operated Relief Valve
PSEG	Public Service Enterprise Group Nuclear LLC
PZR	Pressurizer
RHR	Residual Heat Removal
SCBA	Self Contained Breathing Apparatus
SDP	Significance Determination Process
SPT	Station Power Transformer
SCCI	Substantive Cross-Cutting Issue
SSCs	Systems, Structures and Components
SW	Service Water
SWIS	Service Water Intake Structure
SWP	Service Water Pump