January 31, 2006

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

SUBJECT: SALEM NUCLEAR GENERATING STATION - NRC INTEGRATED INSPECTION REPORT 05000272/2005005 and 05000311/2005005

Dear Mr. Levis:

On December 31, 2005, the US Nuclear Regulatory Commission (NRC) completed an inspection at the Salem Nuclear Generating Station. The enclosed integrated inspection report documents the inspection findings, which were discussed on January 9, 2006, and January 27, 2006, with Mr. T. Joyce and other members of your staff.

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

This report documents four NRC-identified findings and four self-revealing findings of very low safety significance (Green). All of these findings were determined to involve violations of NRC requirements. However, because of the very low safety significance and because they are entered into your corrective action program, the NRC is treating these findings as non-cited violations (NCVs) consistent with Section VI.A.1 of the NRC Enforcement Policy. If you contest any NCV in this report, you should provide a response within 30 days of the date of this inspection report, with the basis for your denial, to the US Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington, DC 20555-0001; with copies to the Regional Administrator, Region I; the Director, Office of Enforcement, US Nuclear Regulatory Commission, Washington, DC 20555-0001, and the NRC Resident Inspector at the Salem Nuclear Generating Station.

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

Mel Gray, Acting Chief
Projects Branch 3
Division of Reactor Projects

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

Enclosure: Inspection Report 05000272/2005005 and 05000311/2005005
w/Attachment: Supplemental Information

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U.S. NUCLEAR REGULATORY COMMISSION

REGION I

Docket Nos.:	50-272, 50-311
License Nos.:	DPR-70, DPR-75
Report No.:	05000272/2005005, 05000311/2005005
Licensee:	Public Service Enterprise Group Nuclear LLC
Facility:	Salem Nuclear Generating Station, Units 1 & 2
Location:	P.O. Box 236 Hancocks Bridge, NJ 08038
Dates:	October 1, 2005, through December 31, 2005
Inspectors:	J. Daniel Orr, Senior Resident Inspector G. Malone, Resident Inspector S. Dennis, Senior Operations Engineer T. O'Hara, Reactor Inspector P. Kaufman, Senior Reactor Inspector J. Furia, Senior Health Physicist J. Josey, Reactor Inspector K. Mangan, Senior Reactor Inspector J. Wiebe, Project Engineer
Approved By:	Mel Gray, Acting Chief Projects Branch 3 Division of Reactor Projects

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SUMMARY OF FINDINGS

IR 05000272/2005005, 05000311/2005005; 10/01/2005 - 12/31/2005; Salem Nuclear Generating Station Units 1 and 2; Equipment Alignment, Maintenance Effectiveness, Maintenance Risk Assessments and Emergent Work Control, Refueling and Other Outage Activities, Access Control to Radiologically Significant Areas, Identification and Resolution of Problems, and Other Activities.

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

A. NRC-Identified and Self-Revealing Findings

Cornerstone: Mitigating Systems

C Green. A self-revealing, non-cited violation of 10 CFR 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," was identified when the 11 safety injection pump discharge valve was discovered closed prior to a routine inservice pump test. The discharge valve was left closed five days earlier at the conclusion of a refueling outage surveillance test due to procedure implementation errors and inadequate operator fundamental standards.

This finding is more than minor because it is associated with the human performance attribute, and it affected the mitigating systems cornerstone objective to ensure the availability of systems that respond to initiating events to prevent undesirable consequences. In accordance with IMC 0609, Appendix A, "Significance Determination of Reactor Inspection Findings for At-Power Situations," the inspectors conducted a Phase 1 SDP screening and determined that a Phase 2 SDP analysis was required because the finding represented an actual loss of safety function of a single train for greater than its Technical Specification (TS) allowed outage time. Using the Phase 2 SDP analysis, the inspectors determined that the risk significance of the finding based on internal initiating events that lead to core damage could have been of substantial safety significance. The inspectors referred the results to a senior reactor analyst (SRA) for further review and a more detailed Phase 3 SDP analysis. The SRA completed a Phase 3 analysis of the finding and determined the issue was of very low safety significance (Green). The Salem Standardized Plant Analysis Risk model Revision 3.21, indicated that the finding increased the chance of core damage, over the 132 hour exposure time, on the order of 1 in 200,000,000 or mid E-9. The performance deficiency has a human performance cross-cutting aspect. (Section 1R04)

C Green. A self-revealing, non-cited violation of 10 CFR 50, Appendix B, Criterion V, “Instructions, Procedures, and Drawings,” was identified when the 22 control area chiller tripped due to its associated condenser service water outlet valve (22SW102) failing closed. The 22SW102 valve was identified one month earlier as having significant wear conditions during a preventive maintenance activity. The conditions were not corrected and the valve was returned to service without further evaluation. The wear conditions were an indication of the 22SW102 ultimate failure condition.

This finding is more than minor because it is associated with the equipment performance attribute, and it affected the mitigating systems cornerstone objective to ensure the availability and reliability of systems that respond to initiating events to prevent undesirable consequences. The chilled water system is listed as a mitigating system in Table 2 of the Risk Informed Inspection Notebook for Salem Generating Station, Revision 2, and provides support and cooling for the control area ventilation system and the emergency control air compressors. This issue also impacted the initiating events cornerstone because unavailability of one train of a chiller increased the likelihood of loss of control area ventilation and loss of control air events. In accordance with IMC 0609, Appendix A, “Significance Determination of Reactor Inspection Findings for At-Power Situations,” the inspectors conducted a Phase 1 SDP screening and determined a more detailed Phase 2 evaluation was required to assess the safety significance because the finding affected two cornerstones (initiating events and mitigating systems). Using the Phase 2 SDP analysis, the inspectors determined that the finding was of very low safety significance (Green). The performance deficiency has a problem identification and resolution cross-cutting aspect. (Section 1R12)

C Green. The inspectors identified a non-cited violation of 10 CFR 50.65, “Requirements for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants,” for a failure to incorporate an unavailable pressurizer power operated relief valve (1PR2) into a risk assessment during emergent maintenance activities. Operators inappropriately assumed that the weekly risk assessments were calculated such that equipment out of service for any portion of the week was calculated out of service for the entire week. The probabilistic risk assessment group changed its practice to only measure risk for actual scheduled maintenance durations.

This finding is more than minor because PSEG failed to adequately consider the unavailability of 1PR2, a risk significant SSC (included in Table 2 of the Salem Phase 2 SDP risk-informed notebook). The finding was evaluated in accordance with Appendix K of Inspection Manual Chapter 0609, “Maintenance Risk Assessment and Risk Management Significance Determination Process,” and is determined to be of very low safety significance (Green). This determination is based on PSEG’s incremental core damage probability calculated to be 1.7E-9 for the 3.2 hours that 1PR2 was out of service. The performance deficiency has a human performance cross-cutting aspect. (Section 1R13)

C Green. The inspectors identified a non-cited violation of 10 CFR 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," because operators did not properly follow a surveillance test procedure for inspecting the emergency core cooling systems (ECCS) containment sump during a closeout inspection. Operators did not identify and document gaps in the sump screen during the inspection, as specified in the procedure.

This finding is more than minor because it affected the design control attribute of the mitigating systems cornerstone objective to ensure the reliability of systems that respond to initiating events to prevent undesirable consequences. In accordance with IMC 0609, Appendix A, "Significance Determination of Reactor Inspection Findings for At-Power Situations," the inspectors conducted a Phase 1 SDP screening and determined the issue to be of very low safety significance (Green). The inspectors reviewed a PSEG engineering evaluation for past operability, and concluded that potentially affected ECCS components and the containment spray system were likely capable of performing their intended safety functions. The finding was not a design or qualification deficiency, did not represent a loss of system safety function, did not represent an actual loss of safety function of a single train for greater than its Technical Specification allowed outage time, did not represent an actual loss of safety function of one or more non-Technical Specification trains of equipment designated as risk significant per 10 CFR 50.65 for greater than 24 hours, and did not screen as potentially risk significant due to external events. The performance deficiency has a human performance cross-cutting aspect, because a design change package did not close some gaps and operators did not identify other sump gaps. (Section 1R20)

Cornerstone: Barrier Integrity

C Green. A self-revealing, non-cited violation of 10 CFR 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," was identified when the 25 containment fan coil unit (CFCU) malfunctioned. The malfunction was a result of previous inadequately performed maintenance. Maintenance technicians did not follow work instructions and incorrectly installed an air booster relay diaphragm to an associated air-operated valve, which resulted in equipment unavailability.

The finding is more than minor because it affected the human performance attribute of the barrier integrity cornerstone objective to provide reasonable assurance that containment barriers protect the public from radionuclide releases caused by accidents or events. In accordance with IMC 0609, Appendix A, "Significance Determination of Reactor Inspection Findings for At-Power Situations," the inspectors were directed to IMC 0609, Appendix H, "Containment Integrity Significance Determination Process," because the finding represented an actual loss of defense-in-depth of a system that controls containment pressure. The finding was determined to be of very low safety significance (Green) because the Salem Units include a large, dry containment and containment fan coil unit failures do not significantly contribute to large early release frequency. The performance deficiency has a human performance cross-cutting aspect. (Section 4OA2.3.b.1)

C Green. A self-revealing, non-cited violation of 10 CFR 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," was identified when the 13 containment fan coil unit (CFCU) malfunctioned. The malfunction was a result of previous inadequately performed maintenance. Maintenance technicians and operations and engineering personnel did not perform comprehensive troubleshooting efforts for an associated service water flow control valve, resulting in repeat malfunctions and extended unavailability of the 13 CFCU.

The finding is more than minor because it affected the human performance attribute of the barrier integrity cornerstone objective to provide reasonable assurance that containment barriers protect the public from radionuclide releases caused by accidents or events. In accordance with IMC 0609, Appendix A, "Significance Determination of Reactor Inspection Findings for At-Power Situations," the inspectors were directed to IMC 0609, Appendix H, "Containment Integrity Significance Determination Process," because the finding represented an actual loss of defense-in-depth of a system that controls containment pressure. The finding was determined to be of very low safety significance (Green) because the Salem Units include a large, dry containment and containment fan coil unit failures do not significantly contribute to large early release frequency. The performance deficiency has a human performance cross-cutting aspect. (Section 4OA2.3.b.2)

C Green. The inspectors identified a non-cited violation of 10 CFR 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," for deficient containment closure controls during the Spring 2005 Unit 1 refueling outage. PSEG did not ensure that one of the containment equipment hatches could be closed, either inside or outside of containment, for a postulated event involving core boiling or fission product release. Installation of either hatch required a heavy lift crane. The inside crane would be affected by high temperatures and high humidity on a loss of decay heat removal with the reactor coolant system vented, and the outside crane was unavailable for several hours during high wind conditions.

The finding is more than minor because it affected the procedure quality attribute of the barrier integrity cornerstone objective to provide reasonable assurance that containment barriers protect the public from radionuclide releases caused by accidents or events. Based upon the finding representing a potential open pathway in the physical integrity of reactor containment while the unit was shutdown, IMC 0609, Appendix H, "Containment Integrity Significance Determination Process," was used to determine the significance of the finding. Appendix H, Table 6.3 was used for the Phase 1 screen. Based upon Salem Unit 2 being a pressurized water reactor with a large, dry containment and the finding impacting an intact containment penetration, the finding required a Phase 2 analysis. The Phase 2 risk approximation determined the finding to be of low to moderate safety significance. Consistent with IMC 0609 guidance, a Senior Reactor Analyst performed a Phase 3 risk assessment to more accurately identify the risk significance and determined the issue to be of very low safety significance (Green). (Section 4OA5.1)

Cornerstone: Occupational Radiation Safety

C Green. The inspectors identified a non-cited violation of 10 CFR 20.1501, "Surveys and Monitoring," for deficient radiological area access control. An NRC inspector was exposed to unanticipated radiation levels of approximately 72 millirem per hour (mrem/hr) because PSEG radiation protection technicians were not directed to survey a residual heat removal (RHR) room after control room operators established the RHR system in a shutdown cooling lineup. Radiation levels in the area were as high as 150 mrem/hr.

The finding is more than minor because it is associated with the program and process attribute of the occupational radiation safety cornerstone and affected the objective to ensure the adequate protection of the worker health and safety from exposure to radiation from radioactive material during routine civilian nuclear reactor operation. Since this occurrence involved workers' unplanned, unintended dose or potential for such a dose that could have been significantly greater as a result of a single minor, reasonable alteration of circumstance, this finding was evaluated in accordance with IMC 0609, Appendix C, "Occupational Radiation Safety Significance Determination Process." The inspectors determined that the finding was of very low safety significance (Green), because it did not involve (1) ALARA planning and controls, (2) an overexposure, (3) a substantial potential for an overexposure, or (4) an impaired ability to assess dose. The performance deficiency has a human performance cross-cutting aspect. (Section 2OS1)

B. Licensee-Identified Violations

None.

REPORT DETAILS

Summary of Plant Status

Unit 1 began the period at 100 percent (%) power and remained at or near 100% power until operators commenced a reactor shutdown and plant cooldown on October 11, 2005, to begin the seventeenth refueling outage. The unit was returned to approximately 100% power on November 8, 2005.

Unit 2 began the period at 100% power. Consistent with procedures, operators reduced power to 64% on December 12, 2005, when the 22 west moisture separator reheat stop valve remained closed during valve surveillance testing. PSEG determined the issue with the stop valve malfunction was only related to a solenoid test valve discrepancy and reopened the valve. Operators returned the unit to near 100% power on the same day.

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems and Barrier Integrity

1R01 Adverse Weather Protection (71111.01)

a. Inspection Scope (2 Samples)

The inspectors performed an inspection for adverse weather protection and reviewed PSEG's procedure SH.OP-DG.ZZ-0011, "Station Seasonal Readiness Guide," Revision 4, to determine the readiness of selected risk significant systems for cold weather conditions and the overall site preparations for the upcoming grassing season expected to begin in February 2006.

In regard to cold weather readiness, the inspectors toured the outlying safety-related structures and focused on the service water (SW) and outside storage tanks: reactor water storage, auxiliary feedwater, and primary water. Heating systems such as house heating boilers, heat trace, and auxiliary building ventilation were also reviewed to verify performance was adequate. Additionally, the SW and safety injection (SI) system engineers were interviewed and notifications associated with the systems reviewed for proper prioritization or timely resolution.

For grassing season preparations, the inspectors interviewed the responsible system engineers to discuss system health reports and to verify outstanding work requests were being addressed in a timely manner. The inspectors attended a seasonal readiness weekly meeting and reviewed outstanding notifications and their associated corrective actions. A walkdown of the circulating water system, associated traveling water screens and screen wash pumps was also performed to assess material condition.

b. Findings

No findings of significance were identified.

1R04 Equipment Alignment (71111.04)

a. Inspection Scope (5 samples)

The inspectors performed a partial walkdown of the following four 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 therefore, potentially increase risk. The inspectors reviewed applicable operating procedures, walked down control system components, and verified that selected breakers, valves, and support equipment were in the correct position to support system operation. Documents reviewed are listed in the attachment.

- 12 service water (SW) train during 11 SW header and 11 component cooling water heat exchanger outage;
- Unit 1 spent fuel pool cooling system during first day of full core offload;
- 12 residual heat removal (RHR) train aligned for shutdown cooling during mode 5; and
- 11 RHR train realigned for emergency core cooling system requirements prior to mode 4 (hot shutdown).

The inspectors also verified that PSEG had properly identified and resolved equipment alignment problems that could cause initiating events or impact the capability of mitigating systems or barriers and entered them into the corrective action program. For a fifth inspection sample, the inspectors specifically reviewed the circumstances involving the 11 safety injection (SI) pump discharge manual valve (11SJ35) being left closed after surveillance testing on November 3, 2005. The inspectors verified that PSEG accurately described and classified the issue in the corrective action program and reviewed the root cause evaluation report and immediate and proposed corrective actions. The inspectors interviewed the Operations Manager to verify that immediate corrective actions were taken to identify potential similar conditions through an extent of condition review.

b. Findings

Introduction: A Green, self-revealing NCV was identified for the failure to comply with 10 CFR 50, Appendix B, Criterion V, “Instructions, Procedures and Drawings.” As a result of an inadequate procedure and poor human performance, the 11 SI pump discharge isolation valve (11SJ35) incorrectly remained closed for five days.

Description: On November 3, 2005, equipment and control room operators performed S1.OP-ST.SJ-0020, “Periodic Leakage Test Reactor Coolant System Pressure Isolation Valves Mode 4,” Revision 15, to demonstrate operability of several Unit 1 reactor coolant system (RCS) pressure isolation valves and other valves associated with the SI and residual heat removal systems. Salem Unit 1 was in Mode 4 and the test was required to be completed prior to entering Mode 3 (hot standby). At the conclusion of testing, procedure step 5.9.3 required operators to return all components listed in

Attachment 1 to the recorded pretest position. Valve 11SJ35 was recorded to have a locked open pretest position. Procedure step 5.9.4 also directed a second operator to perform an independent verification of the components listed in Attachment 1. Contrary to procedure steps 5.9.3 and 5.9.4, valve 11SJ35 was maintained closed.

On November 8, 2005, equipment operators identified valve 11SJ35 as closed while performing a pretest lineup for an 11 SI pump inservice test. The discrepancy was immediately reported to the control room and 11SJ35 was reopened.

PSEG entered this problem into the corrective action program as notification 20260710. PSEG promptly performed an extent of condition review and verified the lineup of several ECCS systems via a locked valve surveillance procedure and a complete safety injection system valve lineup. PSEG also determined that the valve lineup format in S1.OP-ST.SJ-0020, "Periodic Leakage Test Reactor Coolant System Pressure Isolation Valves Mode 4," Revision 15, could create confusion for proper valve realignment. PSEG revised this procedure and similar formatted valve lineup tables in 45 other operating procedures. Operators had used the single independent verification (IV) column in the valve lineup table, intended for IV during final restoration, to record IV for the test lineup. Operators then recorded the final valve position in the margin of the procedure. An equipment operator that performed the final independent verification of 11SJ35 also misunderstood the procedure step to apply to the closed test position. PSEG ultimately determined that the root cause for the misaligned SI pump was a result of inadequate prejob briefs and not clearly defining the roles of individuals performing S1.OP-ST.SJ-0020, "Periodic Leakage Test Reactor Coolant System Pressure Isolation Valves Mode 4."

<u>Analysis</u>: The inspectors determined that PSEG's inadequate procedure and poor operator fundamentals standards, which resulted in the 11SJ35 valve being maintained closed from November 3 to November 8, 2005, constituted a performance deficiency and a finding. This finding is more than minor because it is associated with the human performance attribute, and it affected the mitigating systems cornerstone objective to ensure the availability of systems that respond to initiating events to prevent undesirable consequences. The human performance errors led to unavailability of the 11 SI pump. In accordance with IMC 0609, Appendix A, "Significance Determination of Reactor Inspection Findings for At-Power Situations," the inspectors conducted a Phase 1 SDP screening and determined that a Phase 2 SDP analysis was required because the finding impacted the mitigating systems cornerstone and represented an actual loss of safety function of a single train for greater than its TS allowed outage time. The inspectors noted that Salem Unit 1 secured the residual heat removal system at 9:11 a.m. on November 3, 2005. Therefore, the at-power SDP was applied from that point until November 8, 2005, when valve 11SJ35 was opened.

The Phase 2 SDP analysis was performed using Revision 2 of the Risk-Informed Inspection Notebook for Salem Generating Station. The inspectors assumed the 132 hours of increased unavailability of the 11 SI pump resulted in an exposure time of 3-to-30 days and that no operator recovery credit for the pump was appropriate because the 11SJ35 valve was closed, and remote position indication did not exist in the main control room. The inspectors evaluated all of the SDP Phase 2 worksheets except for the large loss-of-coolant accidents, anticipated transients without scram, loss of control area ventilation, and loss of switchgear ventilaton. The inspectors determined that the risk significance of the finding based on internal initiating events that lead to core damage could have been of substantial safety significance. The inspectors referred the results to a senior reactor analyst (SRA) for further review.

The SRA completed a more detailed Phase 3 analysis of the finding and determined the issue was of very low safety significance (Green). The Salem Standardized Plant Analysis Risk model Revision 3.21, indicated that the finding increased the chance of core damage, over the 132 hour exposure time, on the order of 1 in 200,000,000 or mid E-9. The dominant core damage sequence involved a loss of component cooling water initiating event, followed by charging pump failure, leading to a reactor coolant pump seal loss of coolant accident and subsequent failure of the safety injection pumps. The performance deficiency associated with the inoperable 11 SI pump has a human performance cross-cutting aspect.

Enforcement: 10 CFR 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," requires, in part, that activities affecting quality shall be prescribed by documented procedures and shall be accomplished in accordance with these procedures. Contrary to the above, on November 3, 2005, the surveillance test of RCS pressure isolation valves was not accomplished in accordance with procedure steps 5.9.3 and 5.9.4 of S1.OP-ST.SJ-0020, "Periodic Leakage Test RCS Pressure Isolation Valves Mode 4," Revision 15, and resulted in the 11 SI pump being inoperable. The 11 SI pump was inoperable for five days. Because this finding is of very low safety significance and has been entered into the corrective action program in notification 20260710, this violation is being treated as an NCV, consistent with section VI.A.1 of the NRC Enforcement Policy. **(NCV 05000272/2005005-01, 11 Safety Injection Pump Inoperable due to Operator Procedure Error)**

1R05 Fire Protection (71111.05)

a. Inspection Scope (10 samples)

The inspectors walked down ten fire areas listed below and observed whether there was adequate combustible material control, fire detection and suppression equipment availability and appropriate compensatory measures. The inspectors reviewed Salem's Individual Plant Examination for External Events (IPEEE) for risk insights and design features credited in these areas. The inspectors also referenced Salem's pre-fire plans and NC.DE-PS.ZZ-0001-A6-GEN, "Programmatic Standard Salem Fire Protection Report-General." Documents reviewed are listed in the attachment.

- Unit 1 reactor containment;
- Unit 1 and Unit 2 inner piping penetration area and chiller rooms;
- Fire/Fresh water pump house;
- Unit 1 and Unit 2 charging pump, spray additive tank area;
- Unit 1 and Unit 2 auxiliary building ventilation area;

- Unit 3 gas turbine generator; and
- Station blackout air compressor building.

b. Findings

No findings of significance were identified.

1R06 Flood Protection Measures (71111.06)

a. Inspection Scope (1 sample)

Internal Flooding Review. The inspectors reviewed internal flood protection design features for the Unit 1 and Unit 2 residual heat removal (RHR) pump rooms. The inspectors also reviewed PSEG procedures intended to protect the plant and its safety-related equipment from internal flooding events. The inspectors reviewed flood analysis and design documents, including the updated final safety analysis report (UFSAR), engineering calculations, notifications and orders in regard to RHR room sump pump issues, and abnormal operating procedures. In addition, the inspectors interviewed system engineers and performed a walkdown of the Unit 1 and 2 RHR pump rooms. Documents reviewed are listed in the attachment.

b. Findings

No findings of significance were identified. However, the inspectors observed, during the walkdown, that curbs installed to provide train separation in the event of internal flooding due to a moderate energy line break did not appear to be consistent with the curb configuration described in UFSAR Section 3.6.5.12.5. The inspectors discussed the issue with PSEG and based on that discussion, PSEG initiated notification 20261503 to further evaluate this issue. An initial review by PSEG noted no immediate safety concern due to a review of the Salem Generating Station Probabilistic Risk Assessment Analysis Section 3.10.2, which excluded the RHR pump rooms from the internal flooding analysis, because the rooms do not contain equipment necessary for plant shutdown following a flood initiating event. However, PSEG intended to perform further evaluation to assess the apparent discrepancy between the curb configuration and the UFSAR description in Section 3.6.5.12.5. This issue is unresolved pending completion of PSEG's evaluation and the inspectors' review of the evaluation.
(URI 05000272&311/2005005-02, RHR Room Internal Flood Protection)

1R08 Inservice Inspection Activities (71111.08)

a. Inspection Scope (3 samples)

The inspectors observed selected samples of in-process nondestructive examination (NDE) activities during the Salem Unit 1 Fall refueling outage. The inspectors reviewed selected additional samples of completed NDE and repair or replacement activities. The sample selection was based on the inspection procedure objectives and risk significance of those components and systems where degradation would result in a significant increase in risk of core damage. The observations and documentation reviews were performed to verify that PSEG performed the activities in accordance with the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel (BP&V) Code requirements. The inspectors reviewed a sample of inspection reports and notifications initiated as a result of problems identified during in-service inspection (ISI) examinations. The inspectors also evaluated the effectiveness of the resolution of problems identified during selected ISI activities.

The inspectors reviewed PSEG's boric acid corrosion control (BACC) program. BACC walkdown visual examinations were observed during the first week of the Unit 1 refueling outage. The inspectors verified that the visual inspections emphasized safety significant locations and that boric acid deposits were identified and dispositioned according to procedure. The inspectors reviewed three engineering evaluations for boric acid found on RCS piping and components and verified that the evaluations ensured that ASME Code wall thickness requirements were maintained. Additionally, the inspectors reviewed three corrective actions for identified boric acid leaks and confirmed that the corrective actions were consistent with ASME Code and 10 CFR 50, Appendix B, Criterion XVI requirements.

The inspectors observed the performance of three in-process NDE activities and reviewed documentation and examination reports for an additional twelve NDE activities. The inspectors reviewed four samples of welding activities on the reactor coolant system pressure boundary for the installation of a new pressurizer vent valve (1PS-59) and piping assembly that was fabricated and installed in accordance with the ASME Code during this refueling outage.

The inspectors observed manual ultrasonic testing (UT) and visual examination (VT) activities to verify the effectiveness of the examiner, process, and equipment to identify degradation of risk significant systems, structures and components and to evaluate the activities for compliance with the requirements of ASME Section XI of the Boiler and Pressure Vessel Code.

The inspectors reviewed the Salem Unit 1 reactor vessel closure head (RVCH), Replacement Reactor Vessel Head Penetration NDE Inspection Final Report, AREVA Engineering Information Record 51-5070590-01, which documented the NDE performed to satisfy the requirements in PSEG purchase order 10083253 and PSEG design specification S-C-RC-NGS-0177, Salem Unit 1 Replacement RVCH. The inspectors reviewed a sample of PT records for the J-groove welds, a sample of nine automated UT data sheets, and reviewed video tape and digital photographic records of a sample J-groove welds following completion of the liquid penetrant examinations. The inspectors also reviewed AREVA Engineering Information Record 51-9004788-000, Comparison of Salem Unit 1 to Salem Unit 2 RVCH Examination Data for CRDM Penetration 1. The engineering evaluation concluded that the analysis previously performed by Structural Integrity Associates, Inc. (SIA) to evaluate the potential effects on the structural integrity and future performance of the Salem Unit 2 RVCH was bounding for the Salem Unit 1 RVCH J-groove indications. The SIA evaluation concluded that all regions of the Salem Unit 2 reactor head and nozzles remained well within applicable ASME B&PV Code, Section III limits.

The inspectors reviewed four samples of NDE evaluations which had been initially rejected and subsequently accepted after evaluation.

The inspectors also reviewed four radiographs, RT data sheets, and the examiners' comments noted for the indications identified in weld S1-1-RC-77-3 for the pressurizer vent valve 1PS-59 assembly.

The inspectors observed selected lower head penetration inspection activities and also reviewed photographs and examination reports to determine whether the inspection procedure was effectively implemented. The inspectors observed the review of several penetration nozzles to evaluate the effectiveness of the VT to verify that the penetration intersection location could be fully accessed to perform a 360-degree examination.

The inspectors reviewed Engineering Evaluation No. S-1-RC-MEE-1935, Revision 0, dated October 7, 2005, "1R17 Steam Generator Degradation Report." This report documented that the steam generator degradation, measured in refueling outage 16, was low enough to defer steam generator inspection activities during the present refueling outage 1R17.

The inspectors reviewed the composition of the pressurizer nozzle material and verified that Temporary Instruction 2515/160, "Pressurizer Penetration Nozzles and Steam Space Piping Connections in US Pressurized Water Reactors," was not applicable to Salem Unit 1.

The inspectors reviewed a sample of corrective action notifications listed in the attachment. These notifications involved in-service inspection related problems and were reviewed by the inspectors to ensure that the issues were properly addressed.

b. Findings

No findings of significance were identified.

1R11 Licensed Operator Requalification Program (71111.11)

a. Inspection Scope (1 sample)

Resident Inspector Quarterly Review. The inspectors observed a simulator training scenario conducted on December 13, 2005, to assess operator performance and training effectiveness. The scenario involved a reactor coolant system temperature instrument failure, a steam generator feed pump trip, a pressurizer power operated relief valve failure, a steam generator tube rupture, and a small break loss of coolant accident. The inspectors verified operator actions were consistent with operating, alarm response, abnormal, and emergency procedures. The inspectors assessed simulator fidelity and verified that evaluators identified deficient operator performance where appropriate. The inspectors observed the simulator instructors' critique of operator performance. Documents reviewed to verify proper operator performance and training effectiveness are listed in the attachment.

b. Findings

No findings of significance were identified.

1R12 Maintenance Effectiveness (71111.12)

a. Inspection Scope (2 samples)

The inspectors reviewed performance monitoring and maintenance activities for the two component issues listed below to determine whether PSEG was adequately monitoring equipment performance to ensure their maintenance activities were effective to maintain the equipment reliable. Specifically, the inspectors reviewed the samples for items such as: (1) appropriate work practices; (2) identifying and addressing common cause failures; (3) scoping in accordance with 10 CFR 50.65(b) of the maintenance rule (MR); (4) characterizing reliability issues for performance; (5) trending key parameters for condition monitoring; (6) charging unavailability for performance; (7) classification and reclassification in accordance with 10 CFR 50.65 (a)(1) or (a)(2); and (8) appropriateness of performance criteria for structures, systems, and components classified as (a)(2). Documents reviewed are listed in the attachment.

- 1B emergency diesel generator service water isolation valve failure as documented in PSEG notification 20258400; and
- 22 control area chiller malfunction as documented in PSEG notification 20245496.

b. Findings

Introduction: A Green, self-revealing NCV was identified for the failure to comply with 10 CFR 50 Appendix B, Criterion V, "Instructions, Procedures and Drawings." As a result of an inadequate maintenance procedure and poor corrective action implementation, the 22 control area chiller tripped and was subsequently unavailable for about 26 hours.

Description: On June 1, 2005, maintenance technicians performed work using procedure SC.IC-PM.ZZ-0008, "Maintenance of Bettis Actuator (Model CB)," Revision 8, for the 22 control area chiller condenser service water outlet valve (22SW102). The activity was a regularly scheduled eighteen month preventive maintenance task to disassemble, inspect, reassemble, and test the air actuator installed on the 22SW102 valve. The actuator was rebuilt with new gaskets, o-rings, lubricant, and seal washers. The maintenance technicians and supervisors also identified that the actuator piston slot was worn where it connects to the valve yoke with a pin. A replacement piston was not available at the time of the maintenance and the 22SW102 valve was returned to service with the piston deficiency. Maintenance personnel submitted an N3 notification

(20240985) to document the as left condition and only stated “actuator needed overhaul.”

On July 5, 2005, the 22 control area chiller tripped on high condenser discharge pressure shortly after starting for surveillance testing. The 22SW102 valve had failed closed and resulted in the chiller trip. Maintenance technicians subsequently discovered the actuating pin at the piston to valve yoke broken. PSEG entered the 22 chiller malfunction into the corrective action program as notification 20245496 and evaluated the apparent causes. The 22SW102 valve was rebuilt with a new actuator piston and pin and the 22 chiller returned to an operable status on July 6, 2005. PSEG determined and documented in evaluation order 70050836 that the July 5, 2005, chiller malfunction was a result of the inadequate maintenance performed on June 1, 2005, and stemmed from a lack of guidance in the preventive maintenance order (30100155) and PSEG procedure SC.IC-PM.ZZ-0008. The evaluation stated that specific guidance was not provided to technicians as to when a part is adequate or worn to the point that the part needs replacement. PSEG intended to revise SC.IC-PM.ZZ-0008 as a corrective action.

In addition to the inadequate maintenance procedure, the inspectors noted that the corrective action process, specifically the notification process, was not appropriately used. PSEG procedure, NC.WM-AP.ZZ-0000, "Notification Process," Revision 11 requires that N1 notifications be used to report and screen conditions requiring corrective action or evaluation. N3 notifications, such as was used to report the 11SW102 actuator requiring overhaul, are to be used to provide feedback to the PSEG planning and engineering departments for the improvement of work packages and the preventive maintenance program. Unlike N1 notifications, N3 notifications do not receive the screening and review by senior reactor operators and PSEG managers and are not entered into the work management process for correction. The 22SW102 valve actuator being left in a degraded condition and requiring additional overhaul without an N1 notification has a problem identification and resolution cross-cutting aspect.

Analysis: The inspectors determined that PSEG’s inadequate procedure and poor corrective action performance which resulted in the 22 chiller malfunction on July 5, 2005, constituted a performance deficiency and a finding. This finding is more than minor because it is associated with the equipment performance attribute, and it affected the mitigating systems cornerstone objective to ensure the availability and reliability of systems that respond to initiating events to prevent undesirable consequences. The chilled water system is listed as a mitigating system in Table 2 of the Risk Informed Inspection Notebook for Salem Generating Station, Revision 2 and provides support and cooling for the control area ventilation system and the emergency control air compressors. This issue also impacted the initiating events cornerstone because unavailability of one train of a chiller increased the likelihood of loss of control area ventilation and loss of control air events. In accordance with IMC 0609, Appendix A, “Significance Determination of Reactor Inspection Findings for At-Power Situations,” the inspectors conducted a Phase 1 SDP screening and determined a more detailed Phase 2 evaluation was required to assess the safety significance because the finding affected two cornerstones (initiating events and mitigating systems).

The inspectors conducted a Phase 2 evaluation, using the Loss of Control Area Ventilation (LCAV) and Loss of Control Air (LCA) worksheets from Revision 2 of the Risk Informed Inspection Notebook for Salem Generating Station, and determined the finding was of very low safety significance (Green). The SDP Phase 2 evaluation used the following assumptions:

- An exposure time of less than three days; and
- The initiating event likelihood for LCAV and LCA was increased by one order of magnitude consistent with Rule 1.2 of IMC 0609, Appendix A, "Significance Determination of Reactor Inspection Findings for At-Power Situations."

The loss of control area ventilation core damage sequence was the most dominant core damage sequence.

The performance deficiency had a problem identification and resolution cross-cutting aspect, because the problem was not entered and evaluated in the corrective action program on June 1, 2005.

Enforcement: 10 CFR 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," requires, in part, that instructions, procedures, or drawings shall include appropriate quantitative or qualitative acceptance criteria for determining that important activities have been satisfactorily accomplished. Contrary to the above, PSEG procedure SC.IC-PM.ZZ-0008, "Maintenance of Bettis Actuator (Model CB)," Revision 8 did not contain appropriate quantitative or qualitative acceptance criteria for determining that the actuator piston was in an acceptable condition and was used to inspect valve 22SW102 on June 1, 2005. The deficient procedure acceptance criteria led to a failure of the 22 control area chiller on July 5, 2005. Because this finding is of very low safety significance and has been entered into the corrective action program in notifications 20250328, 20253188, 20254548, and 20254740, this violation is being treated as an NCV, consistent with section VI.A.1 of the NRC Enforcement Policy. **(NCV 05000311/2005005-03, 22 Control Area Chiller Inoperable due to Inadequate Maintenance Procedure)**

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

a. Inspection Scope (5 samples)

The inspectors reviewed the following five activities to verify that the appropriate risk assessments were performed as required 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 to verify that concurrent planned and emergent maintenance and test activities did not adversely affect the plant risk already incurred with these configurations. PSEG's risk management actions were reviewed during shift turnover meetings, control room tours, and plant walkdowns. Documents reviewed are listed in the attachment.

- 1C EDG maintenance concurrent with 11 service water header outage and boron injection tank isolated;
- Unit 1 reactor coolant system at mid-loop configuration;
- 11 component cooling water pump surveillance testing;
- 21 component cooling water and 22 switchgear supply fan out of service concurrently; and
- Unit 1 460 pressurizer level transducer and 1PR2 pressurizer power-operated relief valve out of service concurrently.

b. Findings

Introduction: The inspectors identified a Green NCV for failure to comply with 10 CFR 50.65, "Requirements for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants." PSEG performed an inadequate risk assessment and did not consider a risk significant component (which was included in Table 2 of the Salem Phase 2 SDP risk-informed inspection notebook) for an emergent maintenance activity on the channel II pressurizer level instrument.

Description: On November 15, 2005, control room operators identified that pressurizer level channel II (1LT460) indication drifted high and was no longer within Technical Specification channel check surveillance requirements. Operators appropriately entered and completed the requirements of Technical Specification (TS) action statement 3.3.1.1 action 6. Several hours later, instrument and controls (I&C) technicians identified a very small leak at a swagelock fitting to the bellows for transmitter 1LT460.

To achieve adequate valve isolation for maintenance on 1LT460, it was required that pressurizer pressure channel II (1PT456) instrument also be isolated, because both instruments shared a common sensing line. 1PT456 is also the controlling instrument for 1PR2, a power operated relief valve (PORV). On November 15, 2005, at 4:14 p.m., operators established a tagout for 1LT460 and 1PT456 to facilitate the leak repair. Because 1PT456 was no longer available to control 1PR2, control room operators declared the 1PR2 valve inoperable and entered TS 3.4.3. The block valve (1PR7) to 1PR2 was closed and deenergized at 4:24 p.m. to comply with TS 3.4.3 action b.

At 5:40 p.m., maintenance personnel further evaluated the condition at 1LT460 and determined that an immediate repair to 1LT460 could not be achieved. Operators subsequently restored 1PT456 and returned 1PR2 to an operable status at 5:43 p.m.

At 8:15 a.m. on November 17, 2005, maintenance was resumed on 1LT460 after PSEG further planned the maintenance activity. 1PR2 was inoperable and power was removed from the 1PR7 valve at 8:20 a.m. The inspectors questioned control room operators to determine if PSEG factored the unavailability of the 1PR2 valve and revised the weekly risk assessment. The operators believed that 1PR2 was factored into the risk assessment because it was already considered for a scheduled maintenance activity and the PRA group calculated risk by assuming all affected structures, systems, or components were unavailable for the entire week, even if only scheduled for a short duration. Control room operators consulted with the probabilistic safety assessment group and determined that 1PR2 was not appropriately factored into the weekly risk assessment as an unavailable SSC. The 1PR2 valve was restored to an operable status when the maintenance concluded at 10:04 a.m.

PSEG entered this issue into the corrective action program as notification 20261768 and determined that the probabilistic risk assessment group changed its practice to only measure risk for actual scheduled maintenance durations. PSEG procedure for maintenance risk assessment, SH.OP-AP.ZZ-0027, "On-Line Risk Assessment," Revision 9, was not appropriately revised and operating personnel were not informed of the change.

Analysis: The inspectors determined that PSEG's failure to incorporate the unavailability of the 1PR2 valve into a maintenance risk assessment on November 15 and November 17, 2005, constituted a performance deficiency and a finding. This finding is more than minor because it is similar to example 7.e in Appendix E, "Examples of Minor Issues and Cross-Cutting Aspects," of Inspection Manual Chapter 0612, and PSEG failed to consider 1PR2, a risk significant component (included in Table 2 of the Salem Phase 2 SDP risk-informed notebook). The finding was evaluated in accordance with Appendix K of Inspection Manual Chapter 0609, "Maintenance Risk Assessment and Risk Management Significance Determination Process," and determined to be of very low safety significance (Green), using Flowchart 1. This determination was based on PSEG's incremental core damage probability calculated to be 1.7E-9 for the 3.2 hours that 1PR2 was out of service. The performance deficiency has a human performance cross-cutting aspect.

Enforcement: 10 CFR 50.65 (a)(4), "Requirements for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants," requires, in part, that before performing maintenance activities (including, but not limited to surveillances, post-maintenance testing, and corrective and preventive maintenance), the licensee shall assess and manage the increase in risk that may result from the proposed maintenance activities. Contrary to the above, PSEG did not perform an adequate risk assessment in that the overall maintenance risk assessment performed for plant maintenance on November 15 and 17, 2005, did not assess the total increase in core damage probability due to the unavailability of 1PR2. However, because the finding was of very low safety significance and has been entered into the corrective action program in notification 20261768, this violation is being treated as an NCV, consistent with Section VI.A.1 of the Enforcement Policy. **(NCV 05000272/2005005-04, Inadequate Risk Assessment)**

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

a. Inspection Scope (2 samples)

At the start of the Salem Unit 1 Fall refueling outage on October 11 and 12, 2005, the inspectors observed a reactor shutdown and cooldown. On October 14, 2005, the inspectors observed a reactor coolant system draining evolution as part of Salem Unit 1 outage activities. Reactor coolant was drained to a water level just below the reactor vessel flange in preparation for vessel disassembly. For both evolutions, the inspectors attended the pre-job brief, reviewed main control room logs and plant data via process computers and main control board indications and observed operator performance. The inspectors verified that operators followed established plant procedures and that the plant responded as expected. Documents reviewed are listed in the attachment.

b. Findings

No findings of significance were identified.

1R15 Operability Evaluations (71111.15)

a. Inspection Scope (6 samples)

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

- Condition report (NUCR) 70051042, Unit 1 emergency core cooling system (ECCS) containment sump inspection results;
- NUCR 70050292, reactor bypass trip breaker under-voltage trip assembly performance issues;
- NUCR 70050150, cracked cylinder head on 1C emergency diesel generator;
- NUCR 70051231, abnormal vibrations on 11 component cooling pump;
- Notification 20252881, failure of 16 service water strainer to rotate; and
- NUCR 70051506, operational failure of the 11SW35 valve.

The inspectors reviewed the technical adequacy of the operability determinations to ensure that Technical Specification operability and technical conclusions were justified. The inspectors verified that no unrecognized increase in risk occurred due to the listed conditions. The inspectors also walked down accessible equipment to corroborate the adequacy of PSEG's operability determinations. For the specific case of NUCR 70051042, the inspectors entered the Salem Unit 2 containment and externally observed the ECCS containment sump to verify that similar bypass gaps did not exist in Unit 2. Documents reviewed are listed in the attachment.

b. Findings

No findings of significance were identified.

1R16 Operator Workarounds (71111.16)

.1 Cumulative Operator Workaround Review

a. Inspection Scope (1 sample)

The inspectors conducted a cumulative review of operator workarounds for Salem Units 1 and 2. The review included interviews with licensed operators. The inspectors reviewed Operations Night Orders, a sample of identified operator concerns, and control room logs. Additional documents reviewed are listed in the attachment.

b. Findings

No findings of significance were identified.

.2 Selected Operator Workaround Review

a. Inspection Scope (2 samples)

The inspectors reviewed notifications, condition reports, and operability determinations associated with deficiencies in the automatic tap changers for the 22 and 23 station power transformers to verify these problems did not affect operational plant response to potential grid problems. These selected operator workaround reviews were associated with notifications 20237987 and 20238643. Additional documents reviewed are listed in the attachment.

b. Findings

No findings of significance were identified.

1R19 Post-Maintenance Testing (71111.19)

a. Inspection Scope (6 samples)

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

- Work order (WO) 60049935, 12 charging pump speed increaser replacement;
- WO 60050614, 12 auxiliary feedwater steam generator valve positioner leak;
- WO 30105497, 11AF40 coming off its seat;
- WO 30078649, 1A emergency diesel generator refueling maintenance;
- WO 30105879, replacement of 14 reactor coolant pump seal package; and
- WO 30112336, 11SW122 valve inspection and replacement.

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

b. Findings

No findings of significance were identified.

1R20 Refueling and Other Outage Activities (71111.20)

a. Inspection Scope (1 sample)

The inspectors reviewed the schedule and risk assessment documents associated with the Salem Unit 1 refueling outage to confirm that PSEG appropriately considered risk, industry experience, and previous site-specific problems in developing and implementing a plan that assured maintenance of defense-in-depth systems and barriers. Prior to the refueling outage the inspectors reviewed PSEG's outage risk assessment to identify risk significant equipment configurations and determine whether planned risk management actions were adequate. During the refueling outage the inspectors observed portions of the shutdown and cooldown processes and monitored PSEG controls over the outage activities listed below.

The inspectors observed the Unit 1 shutdown and cooldown on October 11 and 12, 2005, and determined whether cooldown rates met Technical Specification (TS) requirements. The inspectors also observed conditions within containment for indications of unidentified leakage and damaged equipment. The inspectors verified that PSEG managed the outage risk commensurate with the outage plan. The inspectors periodically observed refueling activities from the refueling bridge in containment and the spent fuel pool to verify refueling gates and seals were properly installed and determine whether foreign material exclusion boundaries were established around the reactor cavity. Core offload and reload activities were periodically observed from the control room and refueling bridge to verify whether operators adequately controlled fuel movements in accordance with procedures.

The inspectors verified that tagged equipment was properly controlled and equipment configured to safely support maintenance work. Specifically, the inspectors walked down a service water system tagout for isolating one service water header (WCD 4152138) on October 13, 2005. Equipment work areas were periodically observed to determine whether foreign material exclusion boundaries were adequate. During control room tours, the inspectors verified that operators maintained adequate reactor coolant system (RCS) level and temperature and that indications were within the expected range for the operating mode.

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

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

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

The inspectors reviewed applicable documents associated with the Salem Unit 1 refueling outage as listed in the attachment.

b. Findings

Introduction: The inspectors identified a Green NCV for failure to comply with 10 CFR 50, Appendix B, Criterion V, “Instructions, Procedures, and Drawings,” because operators did not properly follow a surveillance test procedure for inspecting the emergency core cooling systems (ECCS) containment sump during a closeout inspection. Operators did not identify and document gaps in the sump screen during the inspection, as specified in the procedure.

Description: During the Salem Unit 1 Fall 2005 refueling outage, PSEG performed various inspections of the ECCS containment sump. Deficiencies, including several gaps greater than the 1/4" design criteria, were identified and repaired.

On November 1, 2005, near the end of the outage, operators performed surveillance test S1.OP-ST.SJ-0011, "Emergency Core Cooling ECCS Subsystems - Containment Sump Modes 5-6," Revision 3. The purpose of the surveillance test was to satisfy Technical Specification requirements for a visual inspection of the containment sump prior to mode ascension. The containment sump should be specifically inspected for debris and structural distress or corrosion. The surveillance procedure also included a precaution and instruction that no opening greater than 1/4" should exist. Operators completed the surveillance test as acceptable and recorded a statement that no gaps greater than 1/4" were found.

Several hours later, the inspectors requested PSEG open and provide access to the containment sump for NRC review. The inspectors identified three distinct issues not previously identified or corrected by PSEG. The inspectors identified (1) a gap slightly greater than 1/4" by 18" in length at an angle iron to mesh interface at the ceiling of the 1/8" mesh screen, (2) bypass gaps at several supporting rods that penetrated the ceiling mesh, and (3) gaps up to 1" existed at penetrations for containment sump level instruments (these gaps were above the design containment flood level). PSEG identified the gaps at the support rods several days earlier and intended to correct and eliminate the gaps with Design Change Package (DCP) 80086210. The repair plan within DCP 80086210 was revised due to maintenance feedback. The revised repair plan inappropriately did not consider the existing bypass paths at the penetrating support rods.

The containment sump is designed to prevent particles in excess of 1/4" in diameter from passing into the residual heat removal (RHR) suction piping during the recirculation phase of a postulated loss of coolant accident (LOCA). The location and size of the gaps could have allowed particles in excess of 1/4" to enter. Particles entering the suction of the RHR system could adversely affect safety-related systems during the recirculation phase of a LOCA. However, an engineering evaluation for past operability (order 70051127) determined that the screen bypass flowpaths were highly unlikely to adversely affect the operation of downstream ECCS components. The engineering evaluation was based primarily on (1) the largest debris that could pass through would be 3/4", (2) the bypass gaps were at the top of the sump screen and would only pass neutrally buoyant or positively buoyant debris that would likely be flexible type insulation material, (3) flexible type material would likely dislodge at system choke points due to system pressures and significant flow, (4) pump design and construction, and (5) higher probabilities that the debris would be trapped at the containment sump screen. The inspectors also noted that the gaps at the supporting rods were generally obstructed by a keyhole slide plate, but the slide plate was not securely fastened. The inspectors reviewed the engineering evaluation for past operability, and concluded that the potentially affected ECCS components and the containment spray system were likely capable of performing their intended safety functions.

Analysis: The inspectors determined that PSEG's failure to identify and correct containment sump screen bypass issues on November 1, 2005, constituted a performance deficiency and a finding. For the case of the bypass gaps at the supporting rods, PSEG had identified the issue, but ineffectively executed a repair plan. All three identified issues were also unacceptable by PSEG surveillance procedure S1.OP-ST.SJ-0011, "Emergency Core Cooling ECCS Subsystems - Containment Sump Modes 5-6," Revision 3, yet operators did not correctly apply the acceptance criteria.

This finding is more than minor because it affected the design control attribute of the mitigating systems cornerstone objective to ensure the reliability of systems that respond to initiating events to prevent undesirable consequences. In accordance with IMC 0609, Appendix A, "Significance Determination of Reactor Inspection Findings for At-Power Situations," the inspectors conducted a Phase 1 SDP screening and determined the issue to be of very low safety significance (Green). The finding was not a design or qualification deficiency, did not represent a loss of system safety function, did not represent an actual loss of safety function of a single train for greater than its Technical Specification allowed outage time, did not represent an actual loss of safety function of one or more non-Technical Specification trains of equipment designated as risk significant per 10 CFR 50.65 for greater than 24 hours, and did not screen as potentially risk significant due to external events. The performance deficiency associated with the containment sump bypass gaps has a human performance cross-cutting aspect, because a design change package did not close some gaps and operators did not identify other sump gaps.

Enforcement: 10 CFR 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," requires, in part, that activities affecting quality be prescribed by documented instructions, procedures, or drawings, of a type appropriate to the circumstances and shall be accomplished in accordance with these instructions, procedures, and drawings. Contrary to the above, on November 1, 2005, PSEG did not properly perform surveillance test procedure S1.OP-ST.SJ-0011, "Emergency Core Cooling ECCS Subsystems - Containment Sump Modes 5-6," Revision 3, for inspecting the ECCS containment sump. Operators did not identify and document gaps in the sump screen during performance of the procedure for a closeout inspection. Specifically, bypass flow paths exceeding that specified in the procedure existed at containment sump level instrument penetrations, supporting rod penetrations, and at the ceiling of the mesh screen. However, because the finding was of very low safety significance and has been entered into the corrective action program in notification 20259571, this violation is being treated as an NCV, consistent with Section VI.A.1 of the Enforcement Policy. **(NCV 05000272/2005005-05, ECCS Containment Sump Deficiencies)**

1R22 Surveillance Testing (71111.22)

a. Inspection Scope (5 samples)

The inspectors observed portions of and/or reviewed results for five surveillance tests listed below 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, ASME Section XI for valve and pump testing, and 10 CFR 50 Appendix J for containment leak rate tests. The inspectors reviewed applicable documents associated with surveillance testing as listed in the attachment.

- Work Order (WO) 50077245, S1.IC-CC.RM-0014, 1R11A Containment Air Particulate Process Radiation Monitor, Revision 9 (for a reactor coolant system leakage detection surveillance);
- WO 30079193, S1.RA-IS.ZZ-0001, Type B and C Leak Rate Test, Revision 12;
- WO 50075622, S1.OP-ST.SJ-0016, High Head Cold Leg Throttling Valve Flow Balance Verification, Revision 17;
- WO 50075529, S1.OP-ST.SSP-0002, SEC Mode Ops Testing 1A Vital Bus, Revision 16; and
- WO 50089617, S1.OP-ST.CVC-0006, Inservice Testing Chemical and Volume Control Valves Modes 1-6, Revision 14.

b. Findings

No findings of significance were identified.

1R23 Temporary Plant Modifications (71111.23)

a. Inspection Scope (3 samples)

The inspectors reviewed the three temporary modifications listed below and assessed whether PSEG followed its administrative process for implementing the modifications as described in procedure, NC.DE-AP.ZZ-0030, "Control of Temporary Modifications." The associated 50.59 screenings within each temporary modification package were compared against the UFSAR and Technical Specifications. Temporary modifications were walked down and verified installed in accordance with the modification documents and post-installation testing was verified to assure that the actual impact on permanent systems was adequately verified by the tests. Additional documents reviewed are listed in the attachment.

- TM 8085819, Salem Unit 1 Fuel Handling Crane Temporary Power Feed;
- TM 03-017, Install a Temporary Blind Flange in Place of S1CBV-1VC3; and
- TM 80084038, Revise Packing Arrangement for the #23 Service Water Pump.

b. Findings

No findings of significance were identified.

2. RADIATION SAFETY

Cornerstone: Occupational Radiation Safety [OS]

2OS1 Access Control to Radiologically Significant Areas (71121.01)

a. Inspection Scope (9 Samples)

The inspectors reviewed radiation work permits (RWPs) for airborne radioactivity areas with the potential for individual worker internal exposures of >50 mrem committed effective dose equivalent (CEDE) or 20 derived air concentration (DAC)-hrs, and verified adequate barrier integrity and engineering controls performance such as through the use of high efficiency particulate air (HEPA) ventilation.

The inspectors reviewed and assessed the adequacy of PSEG's internal dose assessment for any actual internal exposure greater than 50 mrem CEDE.

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

The inspectors reviewed corrective action reports related to access controls. Included in this review were high radiation area radiological incidents in high radiation areas <1R/hr that have occurred since the last inspection in this area.

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

The inspectors reviewed PSEG documentation packages for all NRC performance indicator events occurring since the last inspection and determined that none of these involved dose rates >25 R/hr at 30 centimeters or >500 R/hr at 1 meter. For unintended exposures >100 mrem total effective dose equivalent (TEDE), >5 rem skin dose equivalent (SDE), or >1.5 rem lens dose equivalent (LDE), the inspectors determined that there were no overexposures or substantial potential for overexposure.

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

The inspectors discussed with first-line health physics (HP) supervisors the controls in place for special areas that have the potential to become VHRA during certain plant operations. The inspectors verified that these plant operations were adequately controlled including communications with the HP and working groups and verified that proper postings and controls existed for the radiation hazards.

The inspectors reviewed radiological problem reports since the last inspection associated with radiation worker errors. The inspectors determined that there were no observable pattern traceable to a similar causes and determined that this perspective matched the corrective action approach taken by PSEG to resolve the reported problems. The inspectors discussed with the RPM any problems with the corrective actions planned or taken. The inspectors verified adequate posting and locking of entrances to high radiation areas and VHRAs.

The inspectors reviewed the radiation work permits (RWPs) and ALARA reviews associated with the Unit 1 reactor vessel head replacement, and conducted direct observations of work being performed during the Unit 1 refueling outage (1R17). Additional documents reviewed are listed in the attachment.

b. Findings

Introduction: A Green NCV of 10 CFR 20.1501 was identified by the NRC regarding an out of date radiological survey. An NRC inspector was exposed to unanticipated radiation levels of approximately 72 millirem per hour because PSEG radiation protection technicians (RPTs) did not survey a residual heat removal (RHR) room after control room operators established the RHR system in a shutdown cooling lineup.

Description: On October 12, 2005, during the Unit 1 refueling outage (1R17), an NRC resident inspector requested to enter the RHR rooms. The RPTs provided a briefing at the health physics control desk and referenced a survey map dated September 9, 2005, for dose rates. The September 9, 2005, dose rates were significantly lower compared to actual conditions as the RHR system was recently placed in a shutdown cooling lineup. ALARA personnel assigned alarming electronic dosimeter setpoints at 10 millirem (low dose limit), 15 millirem (high dose limit), and 80 millirem per hour (dose rate limit). The estimated length of entry into the RHR rooms was established at one hour. Although the RHR pumps were operating at the time of this entry, PSEG did not issue the inspector a special electronic dosimeter normally used in high noise areas.

Within fifteen minutes of entry into the RHR room, the inspector's alarming dosimeter exceeded its low dose limit. The electronic dosimeter indicated an exposure of 12.5 millirem (2.5 millirem above the low dose setpoint), and the average dose rate was 72 millirem per hour. PSEG investigated the cause of the alarm and determined that dose rates in the area were five to ten times higher than that shown on the survey map. A senior health physics technician also recognized that the survey map used to brief the inspector and to establish alarm setpoints was not current, in that it did not reflect actual radiological conditions for the area. PSEG promptly surveyed the RHR rooms and determined that some areas of the RHR rooms were as high 150 millirem per hour. PSEG subsequently determined that the process of performing new radiological surveys for changing plant conditions was generally done via informal communication and was not organizationally controlled.

Analysis: The failure to survey an area subject to changing radiological conditions is a performance deficiency. The finding is more than minor because it is associated with the occupational radiation safety cornerstone attribute of exposure control and affected the cornerstone objective of providing adequate protection of workers from exposure to radiation.

Since this occurrence involved workers' unplanned, unintended dose or potential for such a dose that could have been significantly greater as a result of a single minor, reasonable alteration of circumstance, this finding was evaluated in accordance with IMC 0609, Appendix C, "Occupational Radiation Safety Significance Determination Process." The inspectors determined that the finding was of very low safety significance (Green), because it did not involve (1) ALARA planning and controls, (2) an overexposure, (3) a substantial potential for an overexposure, or (4) an impaired ability to assess dose. PSEG entered this finding into the corrective action program as notification 20256302. The performance deficiency had a human performance cross-cutting aspect.

Enforcement: 10 CFR 20.1501 requires in part, that licensees make, or cause to be made, surveys that are reasonable under the circumstances to evaluate the magnitude and extent of radiation levels to ensure compliance with 10 CFR 20.1201 and plant Technical Specification 6.12. Contrary to this requirement, PSEG failed to survey the Unit 1 RHR rooms, an area subject to changing radiological conditions on October 12, 2005, which resulted in one worker receiving a small, unintended exposure. Because this finding was of very low safety significance (Green), and was entered into PSEG's corrective action program as notification 20256302, this violation is being treated as an NCV consistent with Section VI.A.1 of the NRC Enforcement Policy. **(NCV 05000272/2005005-06, Failure to Perform a Radiological Survey)**

2OS2 ALARA Planning and Controls (71121.02)

a. Inspection Scope (1 Sample)

The inspectors observed radiation worker and RP technician performance during work activities being performed in radiation areas, airborne radioactivity areas, and high radiation areas. The inspectors determined that workers demonstrated the ALARA philosophy in practice and there were no procedure compliance issues. The inspectors also observed radiation worker performance and determined that the training and skill level were sufficient with respect to the radiological hazards and the work involved.

b. Findings

No findings of significance were identified.

2OS3 Radiation Monitoring Instrumentation (71121.03)

a. Inspection Scope (2 Samples)

The inspectors reviewed the plant UFSAR to identify applicable radiation monitors associated with transient high and very high radiation areas, including those used in remote emergency assessment.

The inspectors verified that the calibration expiration and source response checks were current on radiation detection instruments staged for use.

b. Findings

No findings of significance were identified.

Cornerstone: Public Radiation Safety [PS]

2PS2 Radioactive Materials Processing and Shipping (71122.02) and Reactor Vessel Head Replacement Inspection (71007)

a. Inspection Scope (5 Samples)

The inspectors reviewed the solid radioactive waste system description in the UFSAR and the recent radiological effluent release report for information on the types and amounts of radioactive waste disposed, and reviewed the scope of PSEG's audit program to verify that is meets the requirements of 10 CFR 20.1101.

The inspectors walked-down the liquid and solid radioactive waste processing systems to verify and assess that the current system configuration and operation agree with the descriptions contained in the UFSAR and in the Process Control Program (PCP). The inspectors reviewed the status of any radioactive waste process equipment that was not operational or abandoned in place and verified that the changes were reviewed and documented in accordance with 10 CFR 50.59. The inspectors reviewed current processes for transferring radioactive waste resin and sludge discharges into shipping or disposal containers to determine if appropriate waste stream mixing, sampling procedures, and methodology for waste concentration averaging provided representative samples of the waste product for the purposes of waste classification as specified in 10 CFR 61.55.

The inspectors reviewed the radiochemical sample analysis results for each of PSEG's radioactive waste streams, reviewed PSEG's use of scaling factors and calculations used to account for difficult-to-measure radionuclides, and verified that PSEG's program assures compliance with 10 CFR 61.55 and 10 CFR 61.56 as required by Appendix G of 10 CFR Part 20. The inspectors also reviewed PSEG's program to ensure that the waste stream composition data accounts for changing operational parameters and thus remains valid between the annual or biennial sample analysis update.

The inspectors observed shipment packaging, surveying, labeling, marking, placarding, vehicle checks, emergency instructions, disposal manifest, shipping papers provided to the driver, and PSEG verification of shipment readiness. The inspectors verified that the requirements of any applicable transport cask Certificate of Compliance were met, verified that the receiving licensee was authorized to receive the shipment packages, and observed radiation workers during the conduct of radioactive waste processing and radioactive material shipment preparation activities. The inspectors determined that the shippers were knowledgeable of the shipping regulations and that shipping personnel demonstrate adequate skills to accomplish the package preparation requirements for public transport with respect to NRC Bulletin 79-19 and 49 CFR, Part 172, Subpart H. The inspectors verified that PSEG's training program provides training to personnel responsible for the conduct of radioactive waste processing and radioactive material shipment preparation activities.

The inspectors sampled non-excepted package shipment records and reviewed these records for compliance with NRC and DOT requirements. This review included the shipment of the two reactor vessel heads to a processor via barge.

The inspectors reviewed PSEG's Licensee Event Reports, Special Reports, audits, State agency reports, and self assessments related to the radioactive material and transportation programs performed since the last inspection and determined that identified problems were entered into the corrective action program for resolution. The inspectors also reviewed corrective action reports written against the radioactive material and shipping programs since the previous inspection.

Additional documents reviewed are listed in the attachment.

b. Findings

No findings of significance were identified.

4. OTHER ACTIVITIES [OA]

4OA1 Performance Indicator Verification (71151)

b. Inspection Scope

Cornerstone: Occupational Radiation Safety

- Occupational Exposure Control Effectiveness

The inspectors reviewed all PSEG performance indicators (PIs) for the Occupational Radiation Safety cornerstone for follow-up. The inspectors reviewed a listing of PSEG action reports generated from January 2005 through December 2005 to ensure that radiological occurrences were properly classified per NEI 99-02, "Regulatory Assessment Performance Indicator Guideline." These include non-conformances with high radiation areas greater than 1R/hr and unplanned personnel exposures greater than 100 mrem total effective dose equivalent (TEDE), 5 rem skin dose equivalent (SDE), 1.5 rem lens dose equivalent (LDE), or 100 mrem to the unborn child.

The inspectors determined if any of these PI events involved dose rates >25 R/hr at 30 centimeters or >500 R/hr at 1 meter. If so, the inspectors determined what barriers had failed and if there were any barriers left to prevent personnel access. For unintended exposures >100 mrem TEDE, >5 rem SDE, or >1.5 rem LDE, the inspectors determined if there were any overexposures or substantial potential for overexposure.

Cornerstone: Public Radiation Safety

- RETS/ODCM Radiological Effluent Occurrence

The inspectors reviewed a listing of PSEG action reports generated from January 2005 through December 2005 to ensure that radiological effluent occurrences were properly classified per NEI 99-02. These include radiological effluent release occurrences that exceed 1.5 mrem/qtr whole body or 5 mrem/qtr organ dose for liquid effluents, 5 mrads/qtr gamma air dose or 10 mrads/qtr beta air dose, and 7.5 mrems/qtr organ doses from I-131, I-133, H-3 and particulates for gaseous effluents.

b. Findings

No significant findings or observations were identified.

4OA2 Identification and Resolution of Problems (71152)

.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 screening of items entered into the PSEG's corrective action program. This was accomplished by reviewing the description of each new notification and attending daily management screening committee meetings.

.2 Semi-Annual Assessment of 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 and associated notifications 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 notification screening discussed in Section 4OA2.1. Specifically, the inspectors selected an issue pertaining to out of tolerance testing results on several undervoltage (UV) relays associated with 4kV vital busses. The inspectors also included some out of tolerance testing results associated with non-vital electrical bus undervoltage relays. The inspectors reviewed component health reports, interviewed system engineers, and reviewed corrective actions associated with the individual relay tests. Documents reviewed by the inspectors are listed in the attachment.

b. Assessment and Observations

The inspectors noted the potential for an adverse trend in UV relay performance which was not previously identified by PSEG. Discussions were held with the system engineer in regard to this issue and PSEG summarized and assessed the potential performance issue in notification 20265128. PSEG concluded that one of the potential relay performance issues was not expected because a preventive maintenance (PM) task was recently performed on the relay. PSEG intended to review the scope of PM tasks for adequacy. Based on the PM scope issue, PSEG generated a notification 20265128 to review PM scope and frequency, obtain trend data to assess setpoint drift, and based on the trend data evaluate if relay age was a factor. The inspectors reviewed the corrective actions provided PSEG and found them to be adequate.

.3 Annual Sample: Review of Service Water Valve Failures in Containment Fan Coil Unit Systems

a. Inspection Scope

The inspectors reviewed PSEG's actions to resolve problems with service water air operated valves that provide cooling water to the containment fan coil units (CFCUs). Specifically, the inspectors reviewed notifications, evaluations, and reports associated with the CFCU inlet pressure control valves (SW57) and the CFCU outlet flow control valves (SW223 and SW65). These valves were reviewed because they had a history of emergent failures resulting in numerous unplanned Technical Specification action statement entries. The failures included vibration-induced fatigue of control air lines, vibration-induced failure of air booster relay diaphragms, and maintenance-induced errors. The CFCU control loops require relatively frequent adjustments to maintain associated valve strokes within acceptable limits. Each Salem Unit has five CFCUs with each CFCU controlled by the above three valves.

PSEG concluded that many of the problems associated with these valves were intrinsic to the existing system design. The corrective action from past evaluations, including order 70035303 that evaluated a failure of valve 24SW57 to meet stroke requirements, was to implement a major design change to the system. This design change included a fresh-water closed loop cooling system eliminating service water as the cooling medium and eliminating a number of the air-operated flow control valves. PSEG cancelled the closed-loop project in January 2005 to evaluate an alternate and potentially more reliable design.

b. Findings and Observations

1. Unavailability of 25 Containment Fan Coil Unit Due to Deficient Maintenance Practices

Introduction: A Green self-revealing NCV of 10 CFR 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," was identified. As a result of maintenance errors, a malfunction of valve 25SW57 resulted in unavailability of the 25 containment fan coil unit (CFCU).

Description: On October 10, 2005, PSEG performed surveillance testing on the 25 CFCU. Operators determined that the 25 CFCU inlet pressure control valve, 25SW57, maintained downstream pressure at 77 psig instead of the required 49-59 psig. Operators declared the 25 CFCU inoperable and appropriately disabled its operation.

Troubleshooting isolated the problem to an air booster relay in the air operating controls of the valve. The failed booster relay was quarantined and examined by engineers. The examination identified the upper diaphragm had ruptured. The diaphragm is a nylon cloth material coated with rubber on one side and is also shaped asymmetrically.

The booster relay was rebuilt by PSEG in April 9, 2005, under corrective maintenance work order 60042708. The order instructed workers to rebuild the air booster relay in accordance with engineer direction. The work order procedure did not contain separate instructions to rebuild the air booster relay, but listed the vendor manual which contained instructions on replacing the diaphragm. The vendor manual included drawings identifying the correct orientation of the diaphragm within the booster relay.

PSEG performed an apparent cause evaluation of the October 10, 2005, 25SW57 valve malfunction. The evaluation stated that the diaphragm was installed upside-down which allowed air to bleed through the fabric and dis-bond the rubber coating rupturing the diaphragm. PSEG contacted the vendor for an independent assessment. The vendor confirmed that the diaphragm was installed incorrectly.

Analysis: The failure to accomplish maintenance activities in accordance with instructions described in order 60042708 is a performance deficiency. The finding is more than minor because it affected the human performance attribute of the barrier integrity cornerstone objective to provide reasonable assurance that containment barriers protect the public from radionuclide releases caused by accidents or events. The 25 CFCU was unavailable for about 48 hours. In accordance with IMC 0609, Appendix A, "Significance Determination of Reactor Inspection Findings for At-Power Situations," the inspectors were directed to IMC 0609, Appendix H, "Containment Integrity Significance Determination Process," because the finding represented an actual loss of defense-in-depth of a system that controls containment pressure. The finding was determined to be of very low safety significance (Green) because the Salem Units include a large, dry containment and containment fan coil unit failures do not significantly contribute to large early release frequency. The performance deficiency had a human performance cross-cutting aspect.

Enforcement: 10 CFR 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," requires, in part, that activities affecting quality shall be prescribed by documented instructions, procedures, or drawings, of a type appropriate to the circumstances and shall be accomplished in accordance with these instructions, procedures, and drawings. Contrary to the above, PSEG did not accomplish maintenance on the 25SW57 valve using available instructions in corrective maintenance work order 60042708 and incorrectly installed the air booster relay diaphragm on April 9, 2005. The deficient maintenance led to a malfunction of the 25 CFCU on October 10, 2005. Because this finding is of very low safety significance and has been entered into PSEG's corrective action program in notification 20259631, this violation is being treated as an NCV, consistent with section VI.A.1 of the NRC Enforcement Policy. **(NCV 05000311/2005005-07, Inadequate Maintenance Results in Unavailability of 25 Containment Fan Coil Unit)**

2. Unavailability of the 13 Containment Fan Coil Unit Due to Deficient Maintenance Practices

Introduction: A Green self-revealing NCV of 10 CFR 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," was identified. As a result of ineffective maintenance, valve 13SW57 malfunctioned, leading to the unavailability of the 13 containment fan coil unit (CFCU).

Description: On March 15, 2005, PSEG rebuilt valve 13SW57 under preventive maintenance work order 60042739. On March 16, 2005, operators determined that the 13 CFCU inlet pressure control valve, 13SW57, failed to maintain service water pressure in the required range of 49-59 psig. PSEG replaced the air booster relay and the valve subsequently tested satisfactory. PSEG performed a simple corrective action evaluation (order 70045777) and identified several prior valve performance issues associated with the air booster relay in the valve's control system, but did not identify an apparent cause for the March 2005 malfunction. There were also no recommended corrective actions resulting from the apparent cause evaluation.

On April 9, 2005, an equipment operator identified that the 13SW57 valve position was oscillating, causing 13 CFCU inlet pressure to be outside the required band. Instrument and controls (I&C) technicians adjusted the air booster relay and the pressure oscillations ceased. The main control room operators were notified of the adjustment and promptly declared the 13SW57 valve and 13 CFCU inoperable suspecting that 13SW57 was not adequately post-maintenance tested. The operators considered the I&C adjustments to affect the valve performance, specifically its stroke time. PSEG also subsequently investigated other potential 13SW57 valve deficiencies and initiated a troubleshooting plan. The 13CFCU was returned to an operable condition on April 11, 2005, at 10:36 p.m. PSEG initiated two corrective action evaluations to investigate the valve malfunction and the associated maintenance practices: orders 70046795 and 70046548.

Apparent cause evaluation 70046795 identified work management deficiencies associated with the April 9, 2005 repair effort. Specifically, work management procedures existed that allowed technicians to perform maintenance on certain safety related components without a formal work order. These actions were contrary to work management procedures NC.WM-AP.ZZ-0001, "Work Management Process," Revision 10, and NC.WM-AP.ZZ-0000, "Notification Process," Revision 10, which required adjustments or repairs to safety related components that may affect component operability be done under the direction of a work order or a procedure. PSEG also noted that post maintenance tests were not pre-planned for the air booster relay adjustments. Evaluation 70046548 was subsequently closed to apparent cause evaluation 70046441, because the 13SW57 valve again malfunctioned on April 15, 2005.

On April 15, 2005, I&C technicians identified that valve 13SW57 was oscillating, causing 13 CFCU inlet pressure to exceed required limits. Control room operators declared the 13 CFCU inoperable at 10:51 pm on April 15, 2005. PSEG troubleshooting efforts identified control air leaks, an improperly set air pressure regulator to the valve air controls, and that the air booster relay was improperly set. PSEG determined through apparent cause evaluation 70046441 that the cause of the repeat malfunctions could be attributed to human performance, specifically, incomplete troubleshooting.

Analysis: The failure to provide appropriate maintenance instructions to troubleshoot the 13SW57 control systems is a performance deficiency. The finding is more than minor because it affected the human performance attribute of the barrier integrity cornerstone objective to provide reasonable assurance that containment barriers protect the public from radionuclide releases caused by accidents or events. The 13 CFCU was unavailable for less than its Technical Specification allowed outage time. In accordance with IMC 0609, Appendix A, "Significance Determination of Reactor Inspection Findings for At-Power Situations," the inspectors were directed to IMC 0609, Appendix H, "Containment Integrity Significance Determination Process," because the finding represented an actual loss of defense-in-depth of a system that controls containment pressure. The finding was determined to be of very low safety significance (Green) because the Salem Units include a large, dry containment and containment fan coil unit failures do not significantly contribute to large early release frequency. The performance deficiency had a human performance cross-cutting aspect.

Enforcement: 10 CFR 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," requires, in part, that activities affecting quality be prescribed by documented instructions, procedures, or drawings, of a type appropriate to the circumstances and shall be accomplished in accordance with these instructions, procedures, and drawings. Contrary to the above, PSEG failed to provide adequate instructions and to accomplish satisfactory maintenance and post-maintenance tests for the 13SW57 valve on April 9, 2005. The deficient maintenance practices led to a malfunction of the 13 CFCU on April 15, 2005. Because this finding is of very low safety significance and has been entered into PSEG's corrective action program in notification 20233706, this violation is being treated as an NCV, consistent with section VI.A.1 of the NRC Enforcement Policy. **(NCV 05000272/2005005-08, Inadequate Maintenance Practices Result in Unavailability of 13 Containment Fan Coil Unit)**

.4 Annual Sample: Review of Gas Turbine Generator Reliability Issues

a. Inspection Scope

The inspectors reviewed PSEG's actions to improve the reliability of the gas turbine (GT) generator. Historically, the GT tripped numerous times during performance tests and system startup due to electronic control problems. An apparent cause evaluation, 70043624, performed in December 2004 to address the GT not meeting maintenance rule performance criteria, identified several issues affecting GT reliability. Maintaining obsolete control systems functional through refurbishment of components after the component fails was one contributing issue. PSEG initiated three corrective actions to address the control system reliability issues. Two of the corrective actions involved preventive maintenance tasks to clean and inspect controls and relays for the GT. The third corrective action was to replace the existing obsolete controls with a state-of-the-art control system. The inspectors reviewed notifications and interviewed engineers to assess progress in resolving these control reliability issues with the GT.

b. Findings and Observations

No findings of significance were identified.

The inspectors noted that a work order to pull all control related relays and clean and inspect was recommended in evaluation 70042587, because the relays were not cleaned and inspected cleaned since 1996. This work order, created under work order 80077710, was cancelled because a project to replace the control system was in planning stages. However, the project to replace the GT control system was not approved by station management on January 19, 2005. The original plan to pull and clean relays was reevaluated and reinstated on November 23, 2005.

System engineering personnel again presented the control system upgrade project to station management on September 12, 2005. The control system upgrade project has not been approved for funding, but is scheduled to be presented to an approval body in January 2006.

The inspectors observed several corrective action suborders related to the control system upgrade project that were closed without action being taken. The inspectors noted weaknesses in documentation and tracking of evaluations and corrective actions associated with the GT control system.

.5 Annual Sample: Review of Corrective Actions for ECCS Accumulator Pressure Loss

a. Inspection Scope

URI 05000272/2005007-01, Potential for Nitrogen Voiding of ECCS Piping or ECCS Pump Cavitation, was opened pending NRC review of PSEG's evaluation of a condition where the 11 safety injection (SI) accumulator was slowly losing pressure over time. PSEG identified the 11 SI accumulator as losing pressure on August 20, 2004. The inspectors reviewed associated notifications and evaluations to verify that the nitrogen gas was not migrating or collecting within the ECCS pipe systems. URI 05000272/2005007-01 was opened during the Salem 2005 biennial problem identification and resolution inspection and was also an example observation of an incompletely evaluated notification. Specifically, a senior reactor operators' review of the issue only noted that the 11 SI accumulator pressure was within specification and did not consider the potential for nitrogen migration and voiding of connected ECCS pipe systems. The inspectors also assessed PSEG's corrective actions for the inadequate notification review. Documents reviewed are listed in the attachment.

b. Findings and Observations

No findings of significance were identified.

The inspectors found PSEG's final evaluation of the 11 safety injection accumulator pressure loss to be adequate. The evaluation, in part, reviewed the adequacy of PSEG procedure S1.OP-ST.SJ-0009, "Emergency Core Cooling ECCS Subsystems -

Tavg>350EF," Revision 10 used to perform monthly ECCS system high point and pump casing venting. The evaluation considered recent results of that procedure concluding that nitrogen gas was not collecting in ECCS systems.

The inspectors noted additional incomplete evaluations of other SI accumulator issues. In July 2005, while the 11 SI accumulator was still exhibiting nitrogen loss over time, the 22 and 23 ECCS accumulators began to exhibit similar nitrogen losses. However, PSEG's evaluation of the 22 and 23 SI accumulator issues only involved a screening review by SROs and brief statements that accumulator pressure could be maintained within specification. The 14 SI accumulator was most recently identified as exhibiting a level loss over time, and again the issue was reviewed as operable with a brief statement that level and pressure was maintained within specification. The inspectors judged that on the specific issue of SI accumulators losing pressure, operability was not fully evaluated. PSEG entered this observation into the corrective action program as notifications 20265636 and 20266377. The issue was minor because the inspectors did not identify conditions that resulted in accumulator or ECCS system unavailability.

The inspectors also identified that PSEG did not complete corrective maintenance in the Fall Unit 1 refueling outage to resolve the 11 SI accumulator pressure loss. Maintenance work orders were cancelled, based on an inaccurate report that the pressure loss had ceased. PSEG more recently identified external valve packing gland leaks on nitrogen fill lines that when repaired, significantly reduced the 11 SI accumulator pressure loss. PSEG entered this observation into the corrective action program as notification 20267282. URI 05000272/2005007-01 is closed.

4OA3 Event Followup (71153 - 2 samples)

.1 (Closed) LER 05000272/2005004-00, Containment Sump - As Found Condition Not In Accordance With Design Documents

During the Salem Unit 1 Fall refueling outage in October 2005, PSEG discovered several gaps at the ECCS sump mesh screen that would allow flow to bypass the ECCS sump screen. On November 1, 2005, after PSEG had completed a closeout inspection of the ECCS sump, NRC inspectors identified that PSEG did not entirely correct the bypass gaps. That issue is discussed in Section 1R20 of this report. This LER was reviewed by the inspectors, and with the exception of the issue discussed in Section 1R20 of this report, no findings of significance were identified. PSEG documented the gap issues in several notifications including 20258547, 20259571, and 20257255.

.2 (Closed) LER 05000272/2004005-01, ECCS Leakage Outside Containment Exceeds Dose Analysis Limits (11 RHR Heat Exchanger)

This LER is Revision 1 to an LER that discussed ECCS leakage outside containment in excess of dose analysis limits. The leakage occurred after maintenance activities on the 11 residual heat removal heat exchanger head gasket. Revision 0 was discussed in NRC Inspection Report 05000272&311/2005002. Revision 1 incorporated the results of PSEG's root cause analysis on the matter. The inspectors reviewed Revision 1 and verified that the root cause was as previously understood in NRC Inspection Report 05000272&311/2005002. This LER is closed.

4OA5 Other Activities

.1 (Closed) URI 05000272/2005003-05 Containment Closure

a. Inspection Scope

The inspectors completed a followup inspection related to a URI regarding a containment closure issue that was documented in NRC inspection report 05000272&311/2005003. The inspectors' activities focused on determining if PSEG's calculations related to time to boil were adequate and whether containment integrity could have been established prior to the core uncovery and fission product release. The inspectors completed a walk down of the area around containment, interviewed licensee personnel, and reviewed applicable regulatory and industrial guidance on containment closure criteria. Additionally, the inspectors reviewed licensee calculations, operator logs, daily risk analysis data, and containment coordinator logs and turnover sheets to determine the status of containment hatches, equipment available to mitigate a loss of decay heat removal and the status of equipment required to perform PSEG's containment closure procedure. Documents reviewed are listed in the attachment.

b. Findings

Introduction: The inspectors identified a green NCV of 10 CFR 50, Appendix B, Criterion V, "Instructions, Procedures, And Drawings." PSEG's procedure for containment closure during refueling activities was not adequate to ensure that the equipment hatch would be closed prior to a postulated event involving core boiling and subsequent core uncovery with the reactor coolant system (RCS) open to containment atmosphere.

Description: On April 5, 2005, at 8:00 p.m., Salem Unit 2 entered a refueling outage. In order to support routine outage work, PSEG removed both the inner and outage equipment hatch on April 6, at 9:35 a.m. A crane was required to reinstall either the inner or outer equipment hatch. On April 7, 2005, at 4:00 p.m., operators vented the reactor coolant system to the containment atmosphere. On April 10, PSEG installed an outage equipment hatch, which contained a large hinged door. The hinged door could be closed without the use of a crane.

Between April 6 and April 10, PSEG's shutdown risk model determined the calculated time to boil at 9 minutes. PSEG also considered the expected time to establish containment closure at 4 hours. PSEG believed establishing containment closure within 4 hours with these conditions was acceptable. PSEG intended to use procedure S2-OP-AB.CONT-0001, "Containment Closure," Revision 7, to establish containment in the event of a loss of decay heat removal. The procedure directed operators to establish containment closure with either the outage equipment hatch (OEH) door or the inner equipment hatch. In both cases, a crane was required to lift the hatch into position.

The inspectors reviewed the calculations used to demonstrate four hours as an acceptable time to establish containment closure. PSEG stated that because the core would remain covered more than four hours, there would be no fission product release during a postulated loss of decay heat removal event. Additionally, PSEG provided timelines for installing the inner equipment hatch and the OEH. These timelines concluded that either of the two hatches could be installed in less than four hours. Therefore, PSEG believed their conclusions to be acceptable. The inspectors determined that PSEG did not have a calculation to demonstrate that time to core uncovery was greater than four hours. Subsequent to inspector questions, PSEG performed calculations and determined time to core uncovery was greater than 5 hours.

The inspectors reviewed guidance in both NRC Generic Letter (GL) 88-17 "Loss of Decay Heat Removal," Inspection Manual Chapter 0609 Appendix H - "Containment Integrity Significance Determination Process" and NUMARC 91-06 - "Guidelines for the Industry Actions to Assess Shutdown Management." The inspectors concluded that PSEG should establish containment closure prior to time to boil unless PSEG could ensure that containment closure would be established prior to fission product release (core uncovery).

The inspectors reviewed the procedure to install the outage equipment hatch. The inspectors determined that a crane positioned outside containment was to be used to lift the outage equipment hatch into position. The inspectors found that although the crane was properly stationed to position the hatch, there were several periods of time when the crane could not have been used safely due to high winds at the site. PSEG did not identify the high wind conditions as adversely affecting containment closure capability. High winds made the crane unavailable for most of April 7 and 8, 2005.

The inspectors reviewed the procedure to establish containment via the inner equipment hatch. This procedure required operators to use the refueling floor polar crane, which is permanently installed in the upper portion of containment, to move the hatch into position. The inspectors reviewed guidance in GL 88-17 "Loss of Decay Heat Removal" to determine if the crane could be used. In the GL Section 2.2 "Containment Closure" section 2.2.2 states "Reasonable assurance of containment closure should include consideration of activities which must be conducted in a harsh environment. For example, once boiling initiates in the RCS, a large volume of steam may be entering containment..." The inspectors reviewed the PSEG's response to GL 88-17 and found it did not address the use of the polar crane. The inspectors requested for such an evaluation and found that no evaluation was performed to assure that the crane could be operated in degraded conditions. Additionally, evaluations of radiological, temperature or noise conditions were also not performed to assess if operators would be able to work in containment during the event. Subsequent to inspector questions, PSEG performed these evaluations. PSEG revised the time to boil calculation, yielding 40 minutes and determined that containment would be accessible if containment fan coil units were operated. The inspectors noted that the containment closure procedure did instruct operators to immediately restore containment fan coil units if required.

Analysis: The inspectors determined that PSEG's failure to adequately ensure the ability to establish containment closure while the reactor coolant system was vented to atmosphere constituted a performance deficiency and a finding. The failure to verify the ability to establish containment closure within a timely manner was contrary to industry guidance provided in both NUMARC 91-06 and GL 88-17. This finding is more than minor because it affected the procedure quality attribute of the barrier integrity cornerstone objective to provide reasonable assurance that containment barriers protect the public from radionuclide releases caused by accidents or events.

Based upon the finding representing a potential open pathway in the physical integrity of reactor containment, while the unit was shutdown, IMC 0609, Appendix H, "Containment Integrity Significance Determination Process," was used to determine the significance of the finding. The finding was categorized as a Type B finding, related to a degraded condition that has potentially important implications for large early release frequency (LERF) without affecting the likelihood of core damage. Appendix H, Table 6.3 was used for the Phase 1 screen and based upon Salem Unit 2 being a pressurized water reactor with a large, dry containment and the finding impacting an intact containment penetration (equipment hatch removed, but capable of being reinstalled), the finding required a Phase 2 analysis by the Phase 1 screen.

Phase 2 Approximation

The inspectors conducted a Phase 2 risk approximation using Appendix H, Tables 6.4 and 6.8. The following plant conditions and assumptions were used for the Phase 2 assessment:

Plant Conditions:

-the unit was in cold shutdown with the reactor coolant system (RCS) vented (per TS 3.4.10.3.b) and steam generators not available for decay heat removal (POS 2);

-within eight days of shutdown, with high decay heat (TW-E);

-time to boil was less than 30 minutes for the duration of this performance deficiency, (licensee time to boil calculations ranged from 8.5 to 9.5 minutes);

-residual heat removal system was in service; and

-outer containment equipment hatch was unavailable for containment closure (22 hours) due to crane operating restrictions imposed by high wind conditions. The inner containment hatch was physically removed and available for containment closure, but not procedurally designated as the preferred closure mechanism.

Equipment Availability:

-three charging pumps;
-two residual heat removal (RHR) pumps and their associated heat exchangers;
-two safety injection pumps;
-three of six service water pumps always available (No. 4 service water bay out of service (OOS) for approximately 17 hrs of the 22-hrs window, pumps 24, 25 & 26 OOS);
-one offsite power source;
-two emergency diesel generators always available (A EDG OOS approximately 6.5 hours, C EDG OOS approximately 7 hrs, at different times);
-one gas turbine generator; and
-three component cooling pumps and one heat exchanger.

Given the plant conditions at the time and the above stated assumptions, the inspectors determined that PSEG could be credited with in-depth shutdown mitigation capability (Table 6.8). Consequently, this LERF-based finding was determined to be of low to moderate safety significance (White) by the Table 6.4 Phase 2 risk approximation. Consistent with IMC 0609 guidance, the Senior Reactor Analyst (SRA) performed a Phase 3 risk assessment to more accurately identify the risk significance of this LERF-based finding.

<u>Phase 3 Assessment</u>

The Phase 3 analysis was performed using event trees and generic information used to support the analysis performed for SECY 97-168, "Issuance for Public Comment of Proposed Rulemaking Package for Shutdown and Fuel Storage Pool Operation," and IMC 0609, Appendix G. The generic information was modified with plant specific information and with the best available industry initiating event, failure, and recovery probability data. The core damage sequences of interest are as follows:

(Loss of offsite power) * (Failure of available EDGs) * (Failure to recover offsite power) * (Failure of the gas turbine generator);

(Loss of RHR or RHR heat exchanger cooling) * (Failure to recover RHR or RHR cooling) * (Failure to inject to the RCS); and

(Loss of inventory) * (Failure to inject to the RCS).

The SRA made the following assumptions to support the Phase 3 assessment:

-The postulated time to core damage was assumed to be 5.5 hours. The SRA used PSEG's event time-line and supporting calculations for the time to core uncovery estimates associated with when the outside crane was unavailable to install the outside containment equipment hatch due to high winds. The average time to core uncovery was calculated as 5.5 hours and was used to calculate

Loss of Offsite Power (LOOP) non-recovery and RHR cooling non-recovery probabilities.

-The shutdown operations loss of offsite power initiating event frequency used was 1.89E-1/year, taken from NUREG/CR-INEEL/EXT-04-02326, dated October 2004. From Table 4-1, the 5.5 hour offsite power non-recovery probability was interpolated as 0.085. These values for initiating event frequency and non-recovery compare favorably with the NUREG/CR-5496, dated November 1998, values of 0.18/year and 0.07, respectively.

-The probability of failure of the two available EDGs was calculated using the Salem SPAR model, Revision 3.20. The SRA set the A EDG test and maintenance and No. 24 service water pump test and maintenance basic events to TRUE, and determined the loss of emergency power systems probability for this condition to be 1.795E-2. By comparison, the EDG common cause failure probability value is 7.103E-4/hour.

-The loss of RHR cooling water and associated recovery probabilities were taken from EPRI Technical Report 1003113 - An Analysis of Loss of Decay Heat Removal Trends and Initiating Event Frequencies (1989-2000), dated November 2001, Table 7-1 and Table 7-5, respectively. These EPRI values compare favorably with IMC 0609, Appendix G generic values. The loss of RHR cooling water initiating event (IE) was used, vice the loss of RHR system IE, based upon the unavailability of the No. 4 service water bay for maintenance for 17 of the 22 hours of concern.

-The failure probability used for the gas turbine generator is 6.4E-2. This value is based upon the human error probability taken from the Risk-Informed Inspection Notebook for Salem Generating Station, Revision 2. The gas turbine generator must be actuated manually from either the local control panel or control room. The Senior Reactor Analyst considered use of gravity feed from the RWST to the RCS as a possible LOOP sequence mitigation strategy. However, the relatively small RCS vent path through the pressurizer spray line valve PS25 bonnet and the short time to boil condition suggests that the available driving head from the RWST would not be able to overcome the back pressure developed in the reactor vessel and pressurizer following the onset of boiling. Absent a supporting thermal-hydraulic analysis, gravity feed could not be credited in the LOOP sequence.

-The Loss of Inventory (LOI) initiating event likelihood was taken from the Millstone 2 Low Pressure/Shutdown SPAR model and estimated at 1E-5/hour. This value is derived from a likelihood of having a loss of RCS inventory that leads to a loss of RHR function.

Conditional Core Damage Probability Quantification

The LOOP/Station Blackout (SBO) sequence was evaluated as follows:

> (1.89E-1/year average LOOP/shutdown hour) * (1 year/8760 hours) * (22 hours) * (1.795E-2 EDG failure probability) * (0.085 failure to recover offsite power within 5.5 hours) * (6.4E-2 operator fails to place the gas turbine generator in service) = 4.63E-8. The SRA notes that this SBO probability did not credit the gas turbine generator as available to prevent an SBO.

The Loss of RHR Cooling sequence was evaluated as follows:

> (5.4E-6/hour loss of RHR cooling likelihood) * (22 hours) * (0.24 RHR cooling non-recovery probability) * (1E-4 failure of operators to initiate RCS injection) = 2.85E-9

The Loss of Inventory sequence was evaluated as follows:

> (1E-5/hour loss of inventory likelihood) * (22 hours) * (1E-4 failure of operators to initiate RCS injection) = 2.2E-8

Total conditional core damage probability equals the sum of all three sequences:

> 4.63E-8+ 2.85E-9 + 2.2E-8 = 7.12E-8

Delta LERF Risk Estimate

The conditional core damage probability (CCDP) calculated above represents the probability of a spectrum of postulated events that lead to core damage during the 22-hour period that the containment was unable to be closed by procedure, using the outside containment equipment hatch.

As stated above, this finding has potentially important implications for LERF, but does not increase the likelihood of an event or adversely impact the capability of a mitigating system credited to prevent core damage. The metric of interest for this finding is delta LERF. To quantify this finding in terms of delta LERF, the SRA first assumed that all of the sequences that contributed to the CCDP would contribute to a conditional large early release probability. Using the CCDP value, the SRA quantified the associated conditional large early release probabilities (CLERP). The failure to close containment, as a result of the finding, represents a probability of 1.0. The nominal failure to close containment probability, assuming the minimum voluntary action case over all postulated initiators, as defined in SECY 97-168, is 0.25 (a one in four chance of failure). Accordingly, the delta LERP value is calculated by:

> [(1.0) * (2.56E-8)] - [(0.25) * (7.12E-8)] = (0.75) * (7.12E-8) = 5.34E-8

In accordance with IMC 0308, Attachment 3, this numerical result is normalized, by dividing it by one year, to arrive at a delta LERF (in units per year). This finding represents an increase in annualized LERF of 5.34E-8/year, which is of very low risk significance (Green).

Enforcement: 10 CFR Part 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," requires, in part, that activities affecting quality be prescribed by procedures and include appropriate quantitative and qualitative acceptance criteria. Contrary to these requirements, between April 6 and April 10, 2005, PSEG Procedure S2-OP-AB.CONT-0001, "Containment Closure," Revision 7, required to install the inner equipment hatch or outage equipment hatch subsequent to a loss of decay heat removal event, did not ensure that equipment would be available to complete the task in an acceptable time frame. Because this finding is of very low safety significance and has been entered into the corrective action program as notification 20236471, this violation is being treated as an NCV, consistent with Section VI.A.1 of the NRC Enforcement Policy. **(NCV 05000311/2005005-09, Inadequate Containment Closure Procedure Requirements)**

.2 Salem Unit 1 Reactor Vessel Closure Head Replacement (71007)

a. Inspection Scope

The inspectors reviewed the Salem Unit 1 reactor vessel closure head (RVCH) replacement using the guidance in NRC Inspection Procedure 71007, "Reactor Vessel Head Replacement Inspection."

PSEG elected to replace the Salem Unit 1 RVCH during the Fall 2005 1R17 refueling outage due to demonstrated susceptibility of Alloy 600 CRDM nozzles and UNS W86182 weld filler material in the existing RVCH to primary water stress corrosion cracking. The design of the new RVCH is similar to the old RVCH except for the replacement of the Alloy 600 nozzle material and weld material with a new and improved primary water stress corrosion cracking (PWSCC) resistant material (Alloy 690).

The RVCH replacement for Salem Unit 1 was made as a one-piece hemispherical monoblock head forging meeting the requirements of ASME Code Section II, Part A, SA-508, Grade 3, Class 1 with 53 control rod drive mechanism (CRDM) Alloy 690 penetration pressure housing assemblies that were shrunk fit into the RVCH and attached with Alloy 152/52 filler material partial penetration J-groove welds. The replacement CRDMs were harvested and transferred from the old Salem Unit 2 RVCH to the Salem Unit 1 RVCH replacement. The RVCH replacement included a reactor vessel head vent (RVHV) nozzle and a reactor vessel level indication system (RVLIS) nozzle constructed from Alloy 690 material. In addition, a new integrated head assembly (IHA) was designed and procured for the Salem Unit 1 RVCH replacement.

Design and Planning

The inspectors verified that the RVCH related design changes and modifications to components described in the UFSAR were reviewed and documented in accordance with 10 CFR 50.59. The inspectors also reviewed the adequacy of 10 CFR 50.59 applicability reviews, screening evaluations, and safety evaluations for the design changes, modifications, and procedure changes.

To verify that design activities for the Salem Unit 1 RVCH replacement and IHA were performed in accordance with 10CFR 50.59 requirements, the inspectors reviewed applicable design documents related to the components being replaced and compared the changes to the original RVCH that was designed in accordance with design and fabrication specifications Westinghouse E-spec G-676245 and Salem Unit 1 equipment specification E-677165 and ASME Boiler and Pressure Vessel (B&PV) Code, and Section III, 1965 Edition through 1965 Winter Addenda requirements.

The inspectors reviewed the Salem Unit 1 replacement RVCH code reconciliation report which reconciles the requirements of the current code of construction and current owner's requirements to the original owner's requirements and the requirements of the original code of construction.

The inspectors conducted onsite and in-office reviews of design change packages, engineering calculations, analyses, design specifications, material specifications, piping specifications, equipment specifications, installation specifications, certified design reports, RVCH change out execution plan traveler, and drawings for the Salem Unit 1 replacement RVCH and IHA to assess the technical adequacy of the design changes and to verify that the design bases, licensing bases, and the performance capability of the modified components were not degraded through the modifications.

The design and fabrication of the replacement RVCH and IHA were specified by PSEG in certified design specifications. AREVA performed the analyses, calculations or evaluations necessary to support the 10 CFR 50.59 evaluations of the replacement RVCH (S2005-001) and the IHA (S2005-002). The inspectors reviewed the RVCH design in DCP 80057545, Reactor Vessel Closure Head Replacement and the IHA design in DCP 80057546, Salem Unit 1 Integrated Head Assembly. The design change packages for the RVCH and IHA included:

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

The replacement components design was reviewed to the ASME B&PV Code Section III and Section XI, 1998 Edition through 2000 Addenda, applicable sections of Salem Unit 1 UFSAR, material specifications, original Westinghouse Design Specification E-Spec 676245, PSEG replacement design specification S-C-RC-NGS-0177, Replacement Reactor Vessel Closure Heads for Salem Units 1 and 2, and FANP 33-5044672-01, ASME Certified Design Report For Salem Units 1 & 2 Replacement RV Closure Head.

The inspectors also reviewed AREVA Engineering Information Record 51-5044614-00, Metrology Services Photogrammetry Report of the Salem Unit 1 RV and RVH that provided the results of the photogrammetric surveys and analysis of the Salem Unit 1 RV and RVH. Based on the data collected, the photogrammetry information was reconciled to the components design dimensions and no changes were required to the replacement RVH. The inspectors confirmed that the replacement RVH conformed to design drawings and there were no fabrication deviations from design.

RVCH Replacement Lifting/Rigging and Transportation

The adequacy of the lifting and rigging activities associated with Salem Unit 1 RVCH replacement were evaluated and/or tested to verify that the maximum anticipated loads to be lifted would not exceed the capacity of the lifting and rigging equipment and supporting structures. The inspectors reviewed the analysis of the potential impact of load handling activities on the reactor core, spent fuel cooling, and other plant support systems and the consequence of any impact loading of structures, systems, and components due to a RVCH drop accident.

The inspectors reviewed DCP 80056403, Restoration of 230 Ton Polar Crane Capacity and Whiting Corporations' certification letter dated June 9, 2004, reconciling Whiting Corporations' 1994, 10 CFR Part 21 issue. The maximum rated capacity of the Salem Unit 1 Polar crane, which is not single failure proof, was restored to its full original design load capacity of 230 tons by replacing 44 existing bolts located on the sheave nest side plates of the polar crane with 44 (A325) high strength bolts. The inspectors also reviewed the results of completed procedure SC.MD-EU.CRN-0004, "Polar Crane Periodic Inspections and Operational Tests."

The inspectors previously reviewed the adequacy of the transport programs, procedures, and onsite heavy haul path segments for the Salem Unit 2 RVCH replacement which is documented in NRC Inspection Report 05000272&311/2005003.

The inspectors observed the arrival of the RVCH replacement at the Salem site access point on September 12, 2005.

The inspectors reviewed the lessons learned from the transfer of the old and new RVCHs during the previous Salem Unit 2 RVCH replacement performed during the Spring 2005 2R14 refueling outage and verified effective application of the lessons learned.

Reactor Vessel Head Fabrication Inspections

The inspectors performed reviews of design specification S-C-RC-NGS-0177 and PSBP 327343 for the Salem Unit 1 replacement RVCH to verify that the material, design, fabrication, inspection, examination, testing, certification, documentation, and functional requirements specified were consistent with the requirements of the ASME Boiler and Pressure Vessel Code, Section III, Division I, 1998 Edition, through 2000 Addenda.

The inspectors reviewed the Salem Unit 1 RVCH Code Reconciliation report, ASME Code Data Report Form –2, and End of Manufacturing Reports (EMRs) for the Salem Unit 1 RVCH replacement assembly (CC/SA001). The reconciliation report addressed the specified design, materials, fabrication, and examination of the replacement RVCH. The EMRs contained certified material test reports, hydrotest report, hydrotest certificate, compliance certification, heat treatment records, weld records, non-conformance reports, corrective actions, non-destructive evaluations, and weld material acceptance tests for the manufacture of the replacement RVCH. The inspectors verified that the authorized nuclear inspectors at the Framatome, ANP Chalon/Saint-Marcel plant inspected the replacement parts, reviewed the manufacturing reports, certified that the components were fabricated and tested, and NPT code stamped in accordance with the ASME Code, Section III, Division 1.

The inspectors observed the implementation of Framatome ANP manufacturing specification procedure 6 MN 11709, Thin Edge Welding of Components on the Reactor Closure Head Adapters - Automatic TIG Orbital Process - Welding Machine Type PROTIG 315. The inspectors performed field observations of a sample of in-process TIG canopy seal welding activities by Framatome technicians of CRDM latch housings to adapter assemblies CRDM penetration numbers 1, 42, 43, 48 and 54 to ensure that the verifications performed during TIG welding operations, parameter recording verifications, and NDEs performed after the welding.

<u>Pre-Service Inspection (PSI) and Baseline Inspections of Replacement RVCH</u>

The baseline examinations that provides the data for future in-service inspections for CRDM, vent line, RVLIS line and dissimilar metal examinations, and serves as a PSI in accordance with ASME Boiler & Pressure Vessel Code Section XI requirements for dissimilar metal welds and to meet the First Revision to NRC Order EA-03-009, consisted of: (1) automated inside diameter UT and eddy current (ET) examination of 53 CRDM penetrations, RVLIS line penetration, and reactor head vent line penetration, (2) outside diameter and J-groove weld eddy current (ET) examination of 53 CRDM penetrations, RVLIS penetration and the vent line penetration, (3) under head visual test (VT) examination of all J-groove welds and penetration outside diameters, (4) top of head bare metal VT examination of all penetrations, and (5) under head PT examination of all penetration to head J-groove welds using “PT White” acceptance criteria were reviewed by the inspectors and is documented in section 1R08 of this report.

<u>Removal and Replacement of RVCHs</u>

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

The inspectors reviewed activities associated with removal and replacement of the RVCHs. The review focused on applicable lifting and handling procedures. The inspectors reviewed the procedures for heavy lifting and for inspection and testing of the cranes and lifting equipment. The inspectors verified that the capability of the lifting equipment had been inspected, tested, and/or evaluated through engineering calculations and analyses. The inspectors reviewed portions of the preparation, including installation of the lifting and rigging equipment, including a 300 ton crane, used to move the original RVCH out of the Salem Unit 1 containment and onto a transporter and movement of the new RVCH into the Salem Unit 1 containment.

Due to the previous “cheese plate” failure that occurred on April 17, 2005, which supported the top of the CRDMs on the RVCH for Salem Unit 2, during removal of the original RVCH from the Salem Unit 2 containment, potentially damaging some of the CRDMs that were to be installed on the Salem Unit 1 RVCH replacement, the inspectors reviewed AREVA engineering information record 51-5069436-00, Salem Unit 2 CRDM Evaluation, dated July 15, 2005. In addition, the inspectors reviewed FANP 38-5068188-00 and 01 which documented the results of the functional testing of each CRDM assembly. The functional testing was conducted onsite using a Jeumont portable testing rig. The evaluation and test results demonstrated that almost all of the Salem Unit 2 CRDMs were acceptable for use on the Salem Unit 1 RVCH replacement except for those from location 62 (CRDM No. 28M269 and 51 (CRDM No. 25M269).

<u>Post-Installation Verification and Testing</u>

The inspectors verified that the post-maintenance testing (PMT) of the installed component replacements RVCH, IHA, and CRDMs cooling system and rod control system were conducted in accordance with approved procedures and verified the functional testing confirmed the design and established baseline measurements. Specifically, the inspectors reviewed procedures that verified the operability of channel analog functions and the adequacy of CRDM coil currents and sequencing and rod control timing. Additionally, the inspectors reviewed Analysis and Measurement Services (AMS) final report for rod drop times of control and shutdown rods.

No reactor coolant system (RCS) leakage was observed from the replacement RVCH during containment walkdowns performed to procedure SH.RA-IS.ZZ-0005, VT-2 Visual Examination Of Nuclear Class 1, 2, and 3 Systems, at normal operating pressure and temperature by certified VT-2 Level 2 examiners. This was documented on visual examination VT-2 data sheets per PSEG work order 50076195. However, some minor valve packing leaks were observed and corrected from RVLIS valves 1RC906 and 1RC907.

b. <u>Findings</u>

No findings of significance were identified.

.3 (Closed) NRC TI 2515/161, Transportation of Reactor Control Rod Drives in Type A Packages

The inspectors examined site specific records and interviewed cognizant PSEG personnel pertaining to PSEG's use of DOT Specification 7A Type A packaging for the shipment of control rod drive mechanisms for the period between calendar year 2002 and the present. The inspectors examined records for the purpose of determining PSEG's compliance with DOT transportation requirements contained in 49 CFR Parts 173.412 and 173.415. The inspectors determined that Salem had undergone refueling activities between January 1, 2002, and the present; and that it had not shipped irradiated control rod drives in DOT Specification 7A, Type A packages.

.4 (Closed) URI 05000272&311/2005004-03 Service Water Piping Trunnion Support Gaps

URI 05000272&311/2005004-03, Service Water Piping Trunnion Support Gaps, was opened pending review of PSEG's operability determination and engineering calculations associated with a condition where several Unit 1 and Unit 2 large bore service water pipe trunnion supports had gaps and corrosion at the intake structure floor. Specifically the piping supports were SWPS-17, SWPS-33, and SWPS-34 and the gaps were not in conformance with original design plans. The issues were entered into PSEG's corrective action program as notifications 20246849, 20250391, 20251879, and 20255706.

The inspectors reviewed PSEG's calculation 2SC-177, Revision 0, dated October 17, 2005, "Service Water Piping, Inactive Trunnion Support Calculations," which assessed the degraded trunnions and the impact to service water bay piping operability and structural integrity due to inactive supports SWSP-17, SWPS-33 and SWSP-34. Based upon review of the pipe stress and pipe support analysis documented in the above calculation, the inspectors verified that the service water piping system and associated support components maintained structural integrity under all design basis loads with the as-found interim configuration due to the inactive supports. PSEG intends to restore the degraded trunnions to original design following corrective maintenance activities. This URI is closed.

.5 Response to Contingency Events (92709)

a. Inspection Scope

NRC Region I staff and inspectors reviewed PSEG's strike contingency plan prior to the site's security force initiating a possible strike on October 12 - 26, 2005. The staff utilized Inspection Procedure 92709 to determine if PSEG was properly implementing their safeguards contingency plan. Specifically, inspectors verified that the minimum number of qualified personnel were available for proper operation of the facility, reactor operation and facility security were maintained as required, and the strike contingency plan complied with the requirements in Hope Creek and Salem Technical Specifications and the Code of Federal Regulations. NRC staff discussed specific strike provisions with PSEG management regarding the effectiveness of site security, previous and potential safeguards threats, and plans to counter these threats. Ultimately, no strike actions were initiated because a new contract was approved.

b. Findings

No findings of significance were identified.

4OA6 Meetings, Including Exit

NRC/PSEG Management Meeting. The NRC conducted a meeting with PSEG on November 17, 2005, to discuss PSEG's actions to improve performance in problem identification and resolution, and the safety conscious work environment at the Salem and Hope Creek stations. The meeting occurred at the Holiday Inn Select Bridgeport, New Jersey and was open for public observation. A copy of the slide presentations and other background documents can be found in ADAMS under accession number ML053270463.

Exit Meeting Summary. On January 9, 2006, the inspectors presented their overall findings to members of PSEG management, led by Mr. T. Joyce. None of the information reviewed by the inspectors was considered proprietary. The inspectors also conducted an additional exit meeting on January 27, 2006, to members of PSEG management, led by Mr. T. Joyce, to discuss updates from the meeting on January 9, 2006.

ATTACHMENT: SUPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee personnel:
T. Joyce, Salem Vice President
C. Fricker, Plant Manager
S. Robitzski, Salem Engineering Director
T. Gierich, Operations Manager
G. Sosson, System Engineering Manager
R. Gary, Technical Superintendent - Radiation Protection
S. Mannon, Regulatory Assurance Manager
A. Johnson, Supervisor, Civil Design Engineering
D. Labott, Project Manager, Reactor Head Replacement
R. Kalman, Acting Manager of Projects
S. Gurnam, RVCH/SGRP Projects
B. McTigue, RVCH/SGRP Projects
H. Berrick, Nuclear Licensing/Compliance

LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

05000272&311/2005005-02	URI	RHR room internal flood protection (Section 1R06)

Opened/Closed

05000272/2005005-01	NCV	11 safety injection pump inoperable due to operator procedure error (Section 1R04)
05000311/2005005-03	NCV	22 control area chiller inoperable due to inadequate maintenance procedure (Section 1R12)
05000272/2005005-04	NCV	Inadequate risk assessment (Section 1R13)
05000272/2005005-05	NCV	ECCS containment sump deficiencies (Section 1R20)
05000272/2005005-06	NCV	Failure to survey the RHR room (Section 2OS1)
05000311/2005005-07	NCV	Indequate maintenance results in unavailability of 25 containment fan coil unit (Section 4OA2)

05000272/2005005-08	NCV	Inadequate maintenance practices resulted in unavailability of 13 containment fan coil unit (Section 4OA2)
05000311/2005005-09	NCV	Inadequate containment closure procedure requirements (Section 40A5)
05000272/2005004-00	LER	Containment sump - as found condition not in accordance with design documents (Section 4OA3)
05000272/2004005-01	LER	ECCS leakage outside containment exceeds dose analysis limits (11 RHR heat exchanger) (Section 4OA3)

Closed

05000272/2005007-01	URI	Potential for Nitrogen Voiding of ECCS (Section 4OA2)
05000272/2005003-05	URI	Containment Closure (Section 4OA5)
05000272&311/2005004-03	URI	Service Water Piping Trunnion Support Gaps (Section 4OA5)

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
SH.OP-DG.ZZ-0011, Station Seasonal Readiness Guide, Revision 4

Notifications
20261215,20261003, 20261036, 20260641, 20260613, 20229231, 20260636,20261049, 20260585, 20260646, 20260914

Other Documents
2005 Salem Winter Readiness Template
Seasonal Readiness Meeting Minutes - November 17, 2005

Section 1R04: Equipment Alignment

Procedures

S1.OP-SO.RHR-0002, Terminating RHR, Revision 23
S1.OP-SO.RHR-0001, Initiating RHR, Revision 14
S1.OP-SO.SF-0002, Spent Fuel Cooling System Operation, Revision 17
S1.OP-SO.SW-0002, 11 Nuclear Service Water Header Outage, Revision 23

Orders
4152138

Section 1R05: Fire Protection

Procedures
FRS-II-521, Pre-Fire Plan U1 & U2 Inner Piping Penetration Area & Chiller Room, Revision 3
FRS-III-815, Pre-Fire Plan Fire/Fresh Water Pump House, Revision 1
FRS-III-818, Pre-Fire Plan Unit 3 Combustion Turbine, Revision 3
FRS-III-821, Pre-Fire Plan Station Black-Out Air Compressor Building, Revision 1
FRS-II-611, Pre-Fire Plan U1 & U2 Reactor Containment, Revision 5
FRS-II-434, Pre-Fire Plan U1 & U2 Charging Pump, Spray Additive Tank Area, Revision 2
FRS-II-453, Pre-Fire Plan U1 & U2 Auxiliary Building Ventilation Units, Revision 2

Section 1R06: Flood Protection Measures

Drawings
207075 - SGS Units 1 & 2 - Auxiliary Building Floor Plans El. 45 Ft. & 55 Ft.

Notifications
20236975, 20257643, 20236975, 20257643, 20229715, 20236975, 20257643

Orders
70047388, 70035088, 70052389

Other Documents
SGS-UFSAR, Rev.13, Section 3.6.5.12.5, Internal Flooding -RHR Pump Rooms, El. 45 Ft.
SGS-PRA Section 3.10.2, Internal Flooding Analysis

Section 1R08: Inservice Inspection Activities

Procedures
SH.RA-AP.ZZ-8805, Boric Acid Corrosion Management Program, Revision 3
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UT-05-078, 14-PS-1131-2, nozzle to safe end
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PT-05-001, 11-RHREX-OUT
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SC.OP-AP.ZZ-0102, Use of Procedures, Revision 9
S2.OP-AB.PZR-0001, Pressurizer Pressure Malfunction, Revision 14
2-EOP-TRIP-1, Reactor Trip or Safety Injection, Revision 25
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2-EOP-SGTR-4, SGTR with LOCA - Saturated Recovery, Revision 23

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SC.ER-DG.ZZ-0002, System Function Level Maintenance Rule Scoping vs. Risk Reference, Revision 1
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S1.OP-AB.460-0002, Loss of 1B 460/230V Vital Bus, Revision 8
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S1.OP-IO.ZZ-0003, Hot Standby to Minimum Load, Revision 17
S1.OP-IO.ZZ-0005, Minimum Load to Hot Standby, Revision 16

S1.OP-SO.ZZ-0006, Hot Standby to Cold Shutdown, Revision 22
S1.OP-SO.CVC-0006, Boron Concentration Control, Revision 19
S1.OP-SO.RC-0005, Draining the Reactor Coolant System to greater than or equal to 101 Foot Elevation, Revision 25
S1.OP-IO.ZZ-0007, Cold Shutdown to Refueling, Revision 13

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S1.OP-ST.DG-0001, 1A Diesel Generator Surveillance Test, Revision 39
S1.OP-ST.DG-0002, 1B Diesel Generator Surveillance Test, Revision 40
S1.OP-ST.DG-0003, 1C Diesel Generator Surveillance Test, Revision 41
S1.OP-SO.CC-0001, Component Cooling System Operation, Revision 16

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S1.OP-ST.CVC-0004, Inservice Testing - 12 Charging Pump, Revision 17
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S1.OP-ST.AF-0004, Inservice Testing - Auxiliary Feedwater Valves, Revision 13
S1.RA-ST.AF-0004, Inservice Testing Auxiliary Feedwater Valves Modes 1-6 Acceptance Criteria, Revision 13
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SC.MD-PM.DG-0032, Periodic Diesel Engine Inspection Maintenance, Revision 10
S1.OP-ST.RC-0007, Seal Injection Flow, Revision 5
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S1.OP-SO.SF-0002, Spent Fuel Cooling System Operation, Revision 17
SC.RE-SO.NIS-0001, BEACON Operation and Calculation Verification, Revision 4
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S1.OP-IO.ZZ-0003, Hot Standby to Minimum Load, Revision 17
S1.OP-IO.ZZ-0005, Minimum Load to Hot Standby, Revision 16
S1.OP-IO.ZZ-0006, Hot Standby to Cold Shutdown, Revision 22
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S1.OP-ST.SSP-0002, SEC Mode Ops Testing 1A Vital Bus, Revision 16
S1.IC-CC.RM-0041, 1R11A Containment Air Particulate Process Radiation Monitor, Revision 9
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20241026, 20241291, 20241340, 20241823, 20242851, 20242966, 20243251, 20244044, 20244045, 20244380, 20244436, 20244470, 20244573, 20244585, 20245114, 20245683, 20246070, 20247820, 20247961, 20248000, 20248119, 20248127, 20248133, 20248232, 20248425, 20248494, 20248588, 20248898, 20249633, 20250412, 20250569, 20250702, 20251437, 20252258, 20253058, 20253686, 20253690, 20253781, 20253807, 20253882, 20254093, 20254258, 20254313, 20254658, 20254659, 20254975, 20255110, 20255131, 20255135, 20255147, 20255426, 20255890, 20255905

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Procedures
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Procedures
S2.MD-FT.4KV-0003, Vital Bus Undervoltage Testing, Revision 29
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Procedures
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SH.MD-GP.ZZ-0240, System Pressure Test At Normal Operating Pressure And Temperature, Revision 7
SC.MD-EU.CRN-0003, Salem Unit 1 Containment Polar Crane Inspection, Revision 11
S1.IC-ST.RCS-0003, Rod Control System And IRPI Integrated Test, Revision 0
S1.IC-PT.RCS-0008, Control Rod Drive Mechanism Cable Checks, Revision 2
S2.OP-AB.CONT-0001, Containment Closure, Revision 7
SC.MD-FR.CAN-0001, Outage Equipment Hatch Installation, Removal, Seal Replacement and Door Manipulation for Containment Closure, Revision 8
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LIST OF ACRONYMS

ALARA	As Low As Is Reasonably Achievable
AMS	Analysis and Measurement Services
ASME	American Society Mechanical Engineers
B&PV	Boiler and Pressure Vessel
BACC	Boric Acid Corrosion Control
CEDE	Committed Effective Dose Equivalent
CFCU	Containment Fan Coil Unit

CFR	Code of Federal Regulations
CR	Condition Report or Notification
CRDM	Control Rod Drive Mechanism
CVCS	Chemistry and Volume Control System
CW	Circulating Water
DOT	Department of Transportation
ECCS	Emergency Core Cooling System
EMRs	End of Manufacturing Reports
ET	Eddy Current Testing
GT	Gas Turbine
HP	Health Physics
IHA	Integrated Head Assembly
IPEEE	Individual Plant Examination for External Events
ISI	In-Service Inspection
LDE	Lens Dose Equivalent
LERF	Large Early Release Frequency
MT	Magnetic Particle Examination
NCV	Non-cited Violation
NDE	Non-Destructive Examination
PARS	Publicly Available Records
PCP	Process Control Program
PIs	Performance Indicators
PM	Preventative Maintenance
PMT	Post-maintenance Testing
PSEG	Public Service Enterprise Group
PSI	Pre-service Inspection
PT	Liquid Dye Penetrant Testing
PWSCC	Primary Water Stress Corrosion Cracking
RCP	Reactor Coolant Pump
RCS	Reactor Coolant System
RHR	Residual Heat Exchanger
RPM	Radiation Protection Manager
RVCH	Reactor Vessel Closure Head
RVHV	Reactor Vessel Head Vent
RVLIS	Reactor Vessel Level Indication System
RWPs	Radiation Work Permits
SDE	Skin Dose Equivalent
SDP	Significance Determination Process
SI	Safety Injection
SIA	Structural Integrity Associates, Inc.
SSC	Structures, Systems, and Components
SW	Service Water
TEDE	Total Effective Dose Equivalent
UFSAR	Updated Final Safety Analysis Report
UT	Ultrasonic Testing
VHRA	Very High Radiation Area
VT	Visual Examination