May 13, 2004

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

SUBJECT: SALEM NUCLEAR GENERATING STATION - NRC INTEGRATED INSPECTION REPORT 05000272/2004002 and 05000311/2004002

Dear Mr. Anderson:

On March 31, 2004, the U.S. Nuclear Regulatory Commission (NRC) completed an inspection at your Salem 1 & 2 reactor facilities. The enclosed integrated inspection report documents the inspection findings, which were discussed on April 15, 2004 with Messrs. David Garchow, Mike Brothers, Carl Fricker, and other members of your staff.

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

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

Since the terrorist attacks on September 11, 2001, the NRC has issued five Orders and several threat advisories to licensees of commercial power reactors to strengthen licensee capabilities, improve security force readiness, and enhance access authorization. In addition to applicable baseline inspections, the NRC issued Temporary Instruction 2515/148, "Inspection of Nuclear Reactor Safeguards Interim Compensatory Measures," and its subsequent revision, to audit and inspect licensee implementation of the interim compensatory measures required by order. Phase 1 of TI 2515/148 was completed at all commercial nuclear power plants during 2002, and the remaining inspection activities for Salem Generating Station were completed in 2003. The NRC will continue to monitor overall safeguards and security controls at Salem Generating Station.

In accordance with 10 CFR 2.390 of the NRC's "Rules of Practice," a copy of this letter and its enclosure, and your response (if any) will be available electronically for public inspection in the NRC Public Document Room or from the Publicly Available Records (PARS) component of NRC's document system (ADAMS). ADAMS is accessible from the NRC Web site at http://www.nrc.gov/reading-rm/adams.html (the Public Electronic Reading Room).

Sincerely,

/RA/

Daniel J. Holody Jr., Acting Chief
Projects Branch 3
Division of Reactor Projects

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

Enclosure: Inspection Report 05000272/2004002 and 05000311/2004002
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:	05000272/2004002, 05000311/2004002
Licensee:	PSEG LLC
Facility:	Salem Nuclear Generating Station, Units 1and 2
Location:	P.O. Box 236 Hancocks Bridge, NJ 08038
Dates:	January 1, 2004 - March 31, 2004
Inspectors:	J. Daniel Orr, Senior Resident Inspector George J. Malone, Resident Inspector Stephen M. Pindale, Senior Reactor Inspector Todd H. Fish, Senior Operations Engineer Joseph T. Furia, Senior Health Physicist Anthony Dimitriadis, Physical Security Inspector Dana Caron, Physical Security Inspector Neil Della Greca, Senior Reactor Engineer
Approved By:	Daniel J. Holody Jr., Acting Chief Projects Branch 3 Division of Reactor Projects

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SUMMARY OF FINDINGS

IR 05000272/2004002, 05000311/2004002; 01/01/2004 - 03/31/2004; Public Service Electric Gas Nuclear LLC, Salem Units 1 and 2; Maintenance Implementation, Post Maintenance Testing, and Event Followup.

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

A. Inspector Identified and Self-Revealing Findings

Cornerstone: Mitigating Systems

- Green. The inspectors identified a non-cited violation of Technical Specification 6.8.1 for failure to properly plan and perform maintenance in accordance with written procedures for an auxiliary building high energy line break (HELB) blowout panel. The HELB panel was reattached with hardened fasteners disabling its ability to blowout at a sufficiently low building pressure.

  This finding is greater than minor, because it affected the Mitigating System Cornerstone objective of equipment capability, in that equipment necessary to establish cold shutdown conditions during an HELB, could be subjected to a steam plume without proper venting. This finding is of very low safety significance, because redundant blowout panels were unaffected. (Section 1R19).

Cornerstone: Barrier Integrity

- Green. Ineffective problem evaluation, regarding a significant change in stroke time test results for a containment fan cooler unit flow control valve (12SW65), resulted in a valve disc stem severing and was undiscovered until intrusive preventive maintenance occurred. This self-revealing finding represented an NCV for inadequate corrective actions.

  This finding is greater than minor, because it affected the Barrier Integrity Cornerstone objective of assuring that physical design barriers protect the public from radio nuclide releases caused by accidents or events. This finding was evaluated by a senior reactor analyst using the containment integrity significance determination process and determined to be of very low safety significance. (Section 1R12)

- Green. An auxiliary building ventilation (ABV) deficiency was not properly evaluated and corrected, such that a Technical Specification (TS) prohibited condition occurred. Control room operators were made aware that no air flow existed in a portion of the Unit 1 ABV exhaust ducts, yet did not recognize the TS applicability.

  This finding is greater than minor, because it affected the Barrier Integrity Cornerstone objective of assuring that physical design barriers protect the public from radio nuclide releases caused by accidents or events. The finding is of very low safety significance, because the deficient air flow existed in only a portion of the auxiliary building and only represented a degradation of the radiological barrier function of ABV. (Section 4OA3.3)

B. Licensee Identified Violations

- None

REPORT DETAILS

Summary of Plant Status

Unit 1 began the period at 82% power due to circulators being out of service for maintenance and condenser waterbox cleaning. Unit 1 operated at 100% power for the majority of the period, but conducted several downpowers to no less than 80% power for additional circulator maintenance and waterbox cleanings.

Unit 2 began the period at approximately 100% power. On January 16, March 4, and March 25 500kV line outages or switchyard work necessitated Unit 2 operate at reduced power. The power reductions were maintained for about a day and power was maintained no less than about 68%. On March 13, Unit 2 was taken off-line and power maintained at 7% to facilitate 22 steam generator feedwater regulating valve maintenance. Unit 2 was restored to 100% power on March 14.

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, Barrier Integrity

1R01 Adverse Weather Protection (71111.01 - 1 sample)

a. Inspection Scope

The inspectors performed an inspection for adverse weather protection and reviewed PSEG's completed procedure "Station Preparations for Seasonal Conditions," SC.OP-PT.ZZ-0002, after it had been completed for cold weather conditions. The inspectors often toured the outlying safety-related structures on particularly cold days and verified that heating system performance was adequate. Notifications were reviewed on a daily basis to identify any adverse impacts on risk significant equipment from cold weather. The inspectors also interviewed PSEG personnel responsible for evaluating the Salem plants' performance during the cold weather season.

b. Findings

On January 31, 2004, the 11 service water pump traveling water screen (TWS) broke a shear pin due to excessive ice buildup. The 11 service water pump (SWP) remained unavailable for about three days while PSEG completed actions to thaw the ice buildup and repair a leaking screen wash valve which had caused the icing. Two weeks earlier, on January 16, 2004, the inspectors had noticed that the 11 TWS and had some ice buildup. No other TWS had any such ice buildup. The 11 TWS was stationary and lined up for automatic operation. The operators responded to the condition by operating the 11 TWS in continuous mode and verified that the screen would rotate and thaw as the frozen screen elements submerged. This January 31 TWS failure was entered into PSEG's corrective action program as Notification 20175950. On March 5, 2004, PSEG initiated notification 20180280 to evaluate operator response to potential icing conditions at the service water intake structure. This item is unresolved pending completion of

PSEG's evaluation and to understand the existence of a performance deficiency. URI 50-272/04-02-01, Failure of 11 Traveling Water Screen due to Ice Buildup.

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

a. Inspection Scope

The inspectors reviewed a setpoint change that increased full power auctioneered Tave (average reactor coolant system temperature) on Salem Unit 2 from 570.5°F to 572.5°F. This setpoint change was necessary to slightly increase Salem Unit 2 steam generator pressures to match turbine control valve characteristics for a new high pressure (HP) turbine. Control valves were full open after replacement of the HP turbine yet the turbine output was below its 100% capability. An effect of changing full power auctioneered Tave from 570.5 °F to 572.5 °F was anticipated to increase SG pressure by approximately 14 psig and increase throttle pressure at the turbine inlet sufficiently to achieve full power operation. This change was not considered to be a design change. The no-load, hot zero power Tave remained unchanged at 547°F. The inspectors verified that the setpoint change was within the current licensing and design basis.

b. Findings

No findings of significance were identified.

1R04 Equipment Alignment (71111.04 - 3 samples for partial walkdowns, 1 sample for complete system walkdown)

a. Inspection Scope

Partial System Walkdown. The inspectors performed three partial system walkdowns. On January 8, the inspectors verified proper alignment of the 11 auxiliary feedwater (AFW) train while the 12 AFW train was not available due to valve maintenance. Proper alignment of the 22 residual heat removal train was verified on January 13 while the 21 RHR train was unavailable due to scheduled maintenance. The 16 service water pump was walked-down on February 20 to verify the pump was unaffected during the conduct of a freeze seal on its motor cooling return line. The following references were used to verify proper system lineup:

- S1.OP-SO.AF-0001, "Auxiliary Feedwater System Operation"
- Drawing 205236-A-8761-51, "No.1 Unit Auxiliary Feedwater"
- U/2 RHR Mechanical Lineup (ID 1028)
- Drawing 205332 sheet 2, "22 Residual Heat Removal"
- S2.OP-SO.RHR-0002, "Terminating RHR"
- TMOD # 04-009, "16 SW Pump Motor Cooler Alternate Drain Path"

Complete System Walkdown. The inspectors conducted a detailed review of the Unit 1 Chemical Volume and Control System (CVC) on February 25-27, 2004. The inspectors reviewed the UFSAR, CVC system lineup documentation (ID 1076), drawing 205228,

and procedure S1.OP-SO.CVC-0001, “Charging, Letdown, and Seal Injection” to determine proper system configuration. The inspectors reviewed the results of DCP 80065300 which restored charging pump 13 to normal charging functionality to verify system configuration was in accordance with requirements. A detailed walkdown was performed by inspectors to verify key valves were correctly positioned, required electrical power was available, lubrication and cooling support systems were operating satisfactory, and mechanical alignment and condition did not impair system performance.

b. Findings

No findings of significance were identified.

1R05 Fire Protection (71111.05 - 9 samples)

a. Inspection Scope

The inspectors walked down the following nine risk significant areas to observe the operational condition of fire detection, suppression and barrier systems, and to verify the proper control of transient combustibles. The inspectors referenced Salem pre-fire plans and NC.DE-PS.ZZ-0001-A6-GEN, “Programmatic Standard Salem Fire Protection Report - General.”

- Unit 1 & Unit 2 charging pump rooms and containment spray area (84' elevation)
- Unit 1 & Unit 2 auxiliary building ventilation area (122' elevation)
- Unit 2 volume control /boric acid batch tank area (122' elevation)
- Unit 1 & Unit 2 electrical penetration area (78' elevation)
- Unit 1 & Unit 2 mechanical penetration area (78' and 100' elevation)

b. Findings

No findings of significance were identified.

1R11 Licensed Operator Requalification (71111.11 - 1 sample)

a. Inspection Scope

On February 24, 2004, the inspectors observed a licensed operator simulator training scenario to assess operator performance and evaluator and participant post-scenario critiques. The training scenario involved a loss of circulating water and a steam generator tube rupture with a faulted steam generator. The inspectors verified operator actions were consistent with Salem operating, alarm response, abnormal, and emergency procedures. The inspectors also verified that evaluators identified deficient operator performance where appropriate. Training Scenario S-ESG-0401 detailed the scenario events and the expected operator response for each event. Scenario references included various alarm response procedures, technical specifications, the emergency plan, S1.OP-AB.CW-0001, Circulating Water System Malfunction, EOP-

TRIP-1, Reactor Trip or Safety Injection, EOP-SGTR-1, Steam Generator Tube Rupture, and EOP-SGTR-3, Steam Generator Tube Rupture with LOCA - Subcooled Recovery.

b. Findings

No findings of significance were identified.

1R12 Maintenance Implementation (71111.12 - 2 samples for quarterly inspection review, 1 sample for biennial inspection review)

a. Inspection Scope

Routine Maintenance Effectiveness Inspection. The inspectors performed two maintenance effectiveness inspections and reviewed notifications documenting past operating problems, system health reports, and maintenance rule performance criteria to determine if PSEG had effectively monitored the performance of a 25 service water pump traveling water screen (TWS) failure and a 12 containment fan cooler unit (CFCU) service water valve failure. The inspectors interviewed system engineers, valve engineers and maintenance rule program coordinators to determine the effectiveness of established and proposed corrective actions. 10 CFR 50.65, "Requirements for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants" and NUMARC 93-01, "Industry Guideline for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants" were referenced to ascertain the acceptability of PSEG's maintenance rule application.

Biennial Periodic Evaluation Inspection. The inspectors conducted a review of the Salem periodic evaluation of Maintenance Rule implementation required by 10 CFR 50.65 (a)(3). The evaluation covered a period from September 2001 to June 2003. The purpose of this review was to ensure that PSEG effectively assessed Salem (a)(1) goals, (a)(2) performance criteria, system monitoring, and preventive maintenance activities. The inspectors reviewed the assessment to determine whether it was completed within the required time period and that industry operating experience was properly utilized. Additionally, the inspectors assessed whether PSEG appropriately balanced equipment reliability with unavailability when planning maintenance activities.

The inspectors selected a sample of four risk-significant systems in category (a)(1) and (a)(2) status to verify that: 1) failed structures, systems, and components were properly characterized, 2) goals and performance criteria were appropriate, 3) corrective action plans were adequate, and 4) performance was being effectively monitored in accordance with procedure NC.NA-AP.ZZ-0016(Q), "Monitoring the Effectiveness of Maintenance." The following systems were selected for this detailed review:

- Auxiliary Feedwater System
- Gas Turbine
- Residual Heat Removal System
- Emergency Diesel Generators

During the assessment period, these systems were either in (a)(1) status, were previously in (a)(1) status, or had experienced degraded performance. The inspectors reviewed corrective action documents for malfunctions and failures of these systems to determine whether 1) they had been correctly categorized as functional failures, 2) were correctly categorized as maintenance preventable, and 3) system performance was properly evaluated to support appropriate (a)(1) status determinations.

b. Findings

1. Failure to Adequately Evaluate a CFCU Service Water Valve Anomaly

Introduction. An inservice testing result for the 12SW65, 12 CFCU flow control outlet valve was not properly evaluated and corrected, such that the valve disc was discovered separated from the actuator stem during maintenance three months later on March 9, 2004. This resulted in a Green self-revealing NCV.

Description. On December 17, 2003, during conduct of S1.OP-ST.SW-0102, "Inservice Testing Containment Fan Cooler Unit (CFCU) Service Water Valves," 12SW65 stroked slow at 19.22 seconds. 12SW65 had since December 2000, consistently stroked near its inservice testing (IST) reference value of 14.2 seconds during quarterly testing. 19.2 seconds was in the IST required evaluation range and IST engineers and valve engineers evaluated the condition in notification 20170792 as acceptable for continued use.

The engineers reasoned that the valve bearing components were wearing and allowing service water silt to buildup adding friction when the valve was stroked. The valve was stroked a second time at 16.85 seconds, still within the required evaluation range, and the quicker stroke was also reasoned as a result of some silt flushing from the bearing housing. The evaluation stated that previous history with similar valves had shown gradual increases in stroke time and it was not expected that a 25 second open stroke time design limit would be challenged prior to overhauling the valve in March 2004.

A preventive maintenance (PM) valve overhaul had been deferred from September 2003 to March 2004. The PM deferral basis documented in order 80065627 and performed prior to the IST test results, considered consistent IST stroke time performance. The PM deferral also suggested that valve performance could be trended through the IST program. The PM deferral basis was not revisited when the valve suddenly trended into the required evaluation range on December 17, 2003.

The inspectors observed the as-found condition of the failed valve disc and stem and judged, based on the pitting and corrosion on the sheared stem ends, that the valve disc had been separated for some time. The inspectors reviewed other historical CFCU surveillance tests to determine when the valve disc-stem separation may have occurred. S1-OP.PT-SW-0007, "Service Water Biofouling Monitoring Containment Fan Cooler Units" was performed quarterly and on December 15, 2003. The inspectors noted that 12 CFCU motor cooler service water flow had increased significantly on December 15,

2003, two days prior to the unusual IST results. CFCU motor cooler heat exchanger flow would increase with increased back pressure at the 12SW65 valve. The inspectors judged, based on the December 15, 2003 motor cooler flow results, that PSEG should have more thoroughly investigated the valve stroke anomaly on December 17, 2003 when the valve stroked slow. The inspectors also noted that PSEG's evaluation improperly characterized the change in valve stroke time as gradual when it had changed significantly.

Analysis. PSEG's failure to revisit a preventive maintenance deferral basis after the IST stroke characteristic of 12SW65 significantly changed was a performance deficiency. This issue was more than minor because it affected the Barrier Integrity Cornerstone objective of assuring that physical design barriers protect the public from radio nuclide releases caused by accidents or events. The Operating Reactor significance determination process (SDP) Phase 1, IMC 609, Appendix A, directed review of this issue using the Containment SDP, IMC 0609 Appendix H, because the finding reduced the atmospheric pressure control function of the reactor containment. Using Appendix H, this issue was determined to be a Type B finding (only potentially affecting the large early release frequency) of very low safety significance (Green), because the Salem Unit 1 is a large dry containment design.

Enforcement. 10 CFR 50, Appendix B, Criterion XVI, Corrective Action, requires defective equipment be promptly identified and corrected. Contrary to the above, a degraded condition on the 12CFCU outlet flow control valve, 12SW65, was not promptly identified and corrected identified during inservice testing on December 17, 2003. Subsequently, on March 9, 2004, 12SW65 was discovered inoperable (valve disc separated from actuator stem), when it was disassembled for preventive maintenance. Because this failure to promptly identify and correct this condition is of very low safety significance and has been entered into PSEG's corrective action program (Notification 20180763), this violation is being treated as an NCV, consistent with Section VI.A of the NRC Enforcement Policy: NCV 50-272/04-02-02, Failure to Adequately Evaluate a CFCU Service Water Valve Anomaly.

2. Failure of 25 Service Water Traveling Water Screen (SWTWS) due to Inadequate Lubrication

On February 1, 2004, operators heard unusual noises coming from the 25 SWTWS. The screen was taken out of service and the 25 service water pump was declared inoperable. The service water pump remained unavailable for about 155 hours while PSEG replaced the SWTWS. PSEG engineers determined that a head shaft bearing was not adequately lubricated resulting in the head shaft bearing sleeve breaking and scoring the shaft. This issue was entered into PSEG's corrective action program as notifications 20176090 and 20181900. This item is unresolved pending completion of PSEG's evaluation and to understand the existence of a performance deficiency. URI 50-311/04-02-03, Failure of 25 Traveling Water Screen due to Inadequate Lubrication.

1R13 Maintenance Risk Assessments and Emergent Work Evaluation (71111.13 - 4 samples)

a. Inspection Scope

The inspectors reviewed PSEG's planning and risk assessments for four risk significant activities listed below. The inspectors reviewed control room operating logs and PSEG probabilistic safety assessment risk evaluation forms, walked down protected equipment and maintenance locations, and interviewed involved personnel. These reviews were performed to determine whether PSEG properly assessed and managed plant risk, and performed activities in accordance with applicable technical specification and work control requirements. The activities selected were based on plant maintenance schedules and systems that contribute to plant risk. Regulatory Guide 1.182, "Assessing and Managing Risk Before Maintenance Activities at Nuclear Power Plants" was referenced to verify adequacy. The inspectors also referenced PSEG procedure SH.OP-AP.ZZ-0027, "On-Line Risk Assessment."

- 13 auxiliary feedwater pump planned maintenance on January 29, 2004
- 11 residual heat removal pump and room cooler planned maintenance on March 02, 2004
- 11 charging pump planned maintenance on March 10, 2004
- 21 residual heat removal pump, 21 auxiliary feedwater pump, and 21 service water pump concurrent planned maintenance on March 30, 2004

b. Findings

No findings of significance were identified.

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

a. Inspection Scope

On March 13, 2004, the inspectors observed control room operators operate Salem Unit 2 at low power, about 7%, to facilitate maintenance on the 22 steam generator main feedwater regulating valve. The inspectors had observed the power reduction from about 20%. The inspectors observed control room operators verify stable plant conditions before maintenance activities were allowed to proceed with reducing the 22 steam generator's feed capability to its feedwater control bypass valve. The inspectors referenced Salem integrated operating procedures S2.OP-IO.ZZ-0003 through 0005, "Hot Standby to Minimum Load," "Power Operations," and "Minimum Load to Hot Standby."

b. Findings

No findings of significance were identified.

1R15 Operability Evaluations (71111.15 - 5 samples)

a. Inspection Scope

The inspectors reviewed five operability determinations (OD). The reviews assessed technical adequacy, the use and control of compensatory measures, and compliance with the licensing and design basis. The inspectors' review included a verification that the operability determinations were made as specified by PSEG's procedure SH.OP-AP.ZZ-0108, "Operability Assessment and Equipment Control Program." The technical content of the ODs and the follow-up operability assessments were reviewed and compared to applicable technical specifications, the Updated Final Safety Analysis Report, and associated design and licensing basis documents. The following operability issues were reviewed:

- Failure of containment isolation valve 21CA330 to open after it stroked closed (OD 70035933)
- Over-pressurization of 12 charging pump suction piping (OD 70036370)
- Containment spray check valve 22CS21 leakage (Notification 20174376)
- Service water pump 16 reduced motor cooler flow (OD 70036348)
- 13 auxiliary feedwater pump non-ASME inservice vibration testing points in alert (Notifications 20133718, 20146100, 20165881, & 20175830)

b. Findings

No findings of significance were identified.

1R19 Post Maintenance Testing (71111.19 - 2 samples)

a. Inspection Scope

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

- Environmentally qualified limitorque valve motor operator inspection for valve 11CC16, (11 residual heat removal heat exchanger component cooling water flow control valve) on March 2, 2004
- Unit 2 Auxiliary building high energy line break blow out panel installation on February 9, 2004

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

b. Findings

Introduction. A Green NCV was identified for failure to comply with Salem Unit 2 TS 6.8.1.a, i.e., to properly perform maintenance on the Unit 2 auxiliary building high energy line break (HELB) panels.

Description. Each Salem auxiliary building has an HELB panel penthouse on its roof. Four panels are installed with rubber backed thin aluminum washers and will break away on internal pressure in the auxiliary building. The relief path is necessary to release steam and energy during an HELB outside containment.

On February 4, 2004, PSEG documented in notification 20176477 that one of four blowout panels had completely detached from its four mounting bolts. On February 9, 2004, PSEG reinstalled the blowout panel without any detailed work instructions.

On February 12, 2004, the inspectors interviewed maintenance supervisors to understand the repair and potential causes of the panel originally detaching. Answers to the inspectors' questions led the inspectors to believe that the panel had been modified and was now more rigidly attached. The inspectors walked down the blowout panels and discovered that the replaced panel had been installed with sturdy washers compared to the three adjacent panels. The three adjacent panels had obvious thin washers that were rubber backed. PSEG immediately restored the affected HELB panel to the correct configuration.

Analysis. The performance deficiency associated with this issue is incorrect maintenance. The finding adversely impacted mitigation system capability to remain available for establishing cold shutdown conditions during a high energy line break. Because the finding affected the reactor safety mitigating system cornerstone objective, the finding is greater than minor. The inspectors reviewed PSEG's analysis for HELB relief capability with one of four panels disabled (notification 20183994) and determined that this issue screened to green in phase 1 of the significance determination process. The issue did not involve the actual loss of a safety function for mitigation equipment.

Enforcement. Salem Unit 2 TS 6.8.1.a. requires that written procedures shall be established covering the activities in Appendix A of Regulatory Guide 1.33, Revision 2, February 1978, which specifies that maintenance that can affect the performance of safety-related equipment should be properly planned and performed in accordance with written procedures, documented instructions, or drawings appropriate to the circumstances. Contrary to the above, on February 9, 2004, one of the Unit 2 auxiliary building high energy line break panels, was repaired without adequate work instructions to ensure that the panel would breakaway at a sufficiently low pressure. Because the failure to properly perform maintenance on the Unit 2 HELB panels is of very low safety significance and has been entered into PSEG's corrective action program (notification 20177503), this violation is being treated as an NCV, consistent with Section VI.A of the NRC Enforcement Policy: NCV 50-311/04-02-04, Improper Repair to Safety-Related Component.

1R20 Refueling and Other Outage Activities (71111.20 - 1 sample)

a. Inspection Scope

On March 5, 2004, the inspectors observed new fuel receipt inspections performed by PSEG for the upcoming Unit 1 spring refuel outage. The inspectors referenced PSEG procedures SC.RE-FR.ZZ-0001 and 2, "Fuel Handling," and "New Fuel Receipt and Storage."

b. Findings

No findings of significance were identified.

1R22 Surveillance Testing (71111.22 - 7 samples)

a. Inspection Scope

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

- S2.OP-ST.DG-0003, "2C Diesel Generator Surveillance Test" on January 21, 2004
- S2.OP-ST.AF-0004, "Inservice Testing - Auxiliary Feedwater Valves" on January 29, 2004
- S2.OP-ST.SJ-0001, "Inservice Testing - 21 Safety Injection Pump" on February 3, 2004
- S1.IC-TR.RCP-0050, "1PT-534 #13 Steam Generator Steam Pressure Protection Channel I (Channel Time Response Test)" on March 2, 2004
- S2.OP-ST.CS-0001, "Inservice Testing - 21 Containment Spray Pump" on March 3, 2004
- S2.IC-FT.RCP-0001, "2TE411A-B #21 Rx Coolant Loop Delta T-Tavg Protection Channel I" on March 3, 2004

Additionally, the inspectors reviewed PSEG's program for minimizing leakage from emergency core cooling systems outside containment as required by Unit 1 and 2 technical specifications 6.8.4.a. The inspectors referenced PSEG procedure SC.SA-AP.ZZ-0051, "Leakage Monitoring Program," and interviewed control room operators, system engineers, and inservice inspection engineers. On February 3, 2004, the inspectors reviewed combined leakrate data sheets for Units 1 and 2 to ensure that known leakages were below PSEG design limits consistent with 10 CFR 50 Appendix A, Criterion 19. The inspectors also observed on February 3, 2004, the conduct of walkdowns to identify potential leakage sources during a 21-safety injection pump surveillance test.

b. Findings

No findings of significance were identified.

1R23 Temporary Plant Modifications (71111.23 - 2 samples)

a. Inspection Scope

The inspectors reviewed two temporary plant modifications (TMODs). TMOD #04-009, "16 SW Pump Motor Cooler Alternate Drain Path" installed a hose on a drain valve downstream of the 16 service water pump motor cooler which directed the motor cooler water to a sump in the service water bay instead of the normally hard-piped cooler discharge. TMOD #04-009 was installed to perform maintenance on a check valve in the normal discharge line. The inspectors reviewed the UFSAR, drawing 205242, TMOD #04-009, performed field observations, and interviewed operations personnel to verify that the modification was consistent with the design requirements and temporary modification documents. The inspectors observed post-installation tests from the control room to verify the system performed its function satisfactorily. TMOD #04-010, "Install a Temporary Gag on S1FHV-1FHV6 in Full Open Position," installed a device on a fuel-handling building (FHB) exhaust fan ventilation damper that gagged it in the full open position. The device was installed because the damper was drifting closed and reduced the fan's capability to maintain correct negative internal pressure in the FHB. The inspectors reviewed the UFSAR, drawing 205321, TMOD #04-010, system training documents (lesson plan number NOS05FHVENT-02) and performed field observations to verify that the modification did not reduce design requirements and was consistent with temporary modification documents.

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 - 2 samples)

a. Inspection Scope

The inspector identified two exposure significant work areas within radiation areas, high radiation areas (<1 R/hr), or airborne radioactivity areas in the plant (Unit 1 and Unit 2 volume control tank rooms) and reviewed associated PSEG controls and surveys of these areas to determine if controls (e.g., surveys, postings, barricades) were acceptable.

The inspector walked down these areas or their perimeters to determine: whether prescribed RWP, procedure, and engineering controls were in place, whether PSEG surveys and postings were complete and accurate, and whether air samplers were properly located. The controls implemented were compared to those required under plant technical specifications (TS 6.12) and 10 CFR 20, Subpart G, for control of access to high and locked high radiation areas.

b. Findings

No findings of significance were identified.

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

a. Inspection Scope

The inspector obtained from PSEG a list of work activities (indicating actual/estimated exposure) completed during the last outage (2R13), and selected the two work activities of highest exposure significance (nozzle dam installation/removal and eddy current testing). The inspector reviewed the ALARA work activity evaluations, exposure estimates, and exposure mitigation requirements. The inspector determined that PSEG had established procedures, engineering and work controls, based on sound radiation protection principles, to achieve occupational exposures that are ALARA.

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

The exposure goal for 2R13 was established at 108.5 person-rem, with a stretch goal of 97.7 person-rem. Actual exposures during the outage were 101.1 person-rem. Major work activities and their dose goals included: nozzle dam installation/removal (goal: 8.325 person-rem; actual: 6.466 person-rem); eddy current testing (goal: 7.665 person-rem; actual: 6.059 person-rem); sludge lancing (goal: 2.675 person-rem; actual: 3.981 person-rem); inservice inspections (goal: 12.218 person-rem; actual: 10.617 person-rem); and, reactor disassembly (goal: 5.850 person-rem; actual: 4.045 person-rem).

b. Findings

No findings of significance were identified.

2OS3 Radiation Monitoring Instrumentation (71121.03 - 2 samples)

a. Inspection Scope

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

The inspector reviewed the qualification documentation for onsite personnel designated to perform maintenance on the vendor-designated vital components, and the vital component maintenance records for three SCBA units currently designated as “ready for service.” For the same three units, the inspector determined that the required, periodic air cylinder hydrostatic testing was documented and up to date, and the DOT required retest air cylinder markings were in place.

The inspector reviewed field radiological controls instrumentation utilized by radiation protection (RP) technicians and plant workers to measure radioactivity, including portable field survey instruments, friskers and portal monitors. The inspector conducted a review of selected radiation protection instruments observed in the radiologically controlled area (RCA). Items reviewed were: verification of proper function; certification of appropriate source checks; and, calibration of those instruments used to ensure that occupational exposures were maintained in accordance with 10 CFR 20.1201.

b. Findings

No findings of significance were identified.

4. OTHER ACTIVITIES [OA]

4OA1 Performance Indicator Verification (71151 - 7 samples)

a. Inspection Scope

The inspectors sampled PSEG submittals for the performance indicators (PIs) listed below. To verify the accuracy of the PI data reported during that period, PI definitions and guidance contained in NEI 99-02, "Regulatory Assessment Indicator Guideline," Rev. 1, were used to verify the basis in reporting for each data element.

Mitigating Systems Cornerstone

- High Pressure Injection Systems Unavailability
- Emergency AC Power Systems Unavailability

The inspectors reviewed licensee unavailability tracking documents and station operating logs to verify that the number of unavailability hours logged matched those reported for Unit 1 and Unit 2 for July 2003 through December 2003.

Physical Protection Cornerstone

- Protected Area Equipment
- Personnel Screening Equipment
- FFD/Personnel Reliability Program

The inspectors interviewed security personnel and reviewed PSEG's tracking and trending reports and security event reports for the PI data collected from July 2003

through March 2004. The inspectors noted from PSEG's submittal that there were no reported failures to properly implement the requirements of 10 CFR 73 and 10 CFR 26 during the reporting period.

b. Findings

No findings of significance were identified.

4OA2 Problem Identification and Resolution (71152)

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

1. Annual Sample Review (1 sample)

a. Inspection Scope

The inspectors selected notifications and other reports associated with four related issues for detailed review. The issues were associated with discoloration of oil found in component cooling pump bearing reservoirs, incorrect level settings on bearing lube oilers on safety related pumps, installation of a component cooling pump bearing labyrinth seal upside down, and an engineering evaluation to replace the oilers on safety related pumps with a different type. The orders were reviewed to ensure that the full extent of the issues were identified, an appropriate evaluation was performed, and appropriate corrective actions were specified and prioritized. The inspectors interviewed plant personnel involved in corrective action development and completion to verify satisfactory completion. The inspectors referenced PSEG's corrective action program document, NC.WM-AP.ZZ-0002, "Performance Improvement Process," and 10 CFR 50, Appendix B, Criterion XVI, "Corrective Action."

b. Findings and Observations

There were no findings of significance identified associated with the issues and sample reviewed. However, the inspectors noted two weaknesses with PSEG's corrective actions on the issue.

- PSEG missed opportunities to train personnel on deficiencies identified through apparent cause determination activities associated with the deficiencies reviewed. Specifically, order 70030582 called for maintenance training regarding correct setup for two installed oiler types. The order intended to have the information disseminated to maintenance technicians by adding new information in existing training materials. Using existing lesson plans would have significantly delayed recent lessons learned from plant problems by several months. No immediate training had been provided to maintenance crews.

- Notification 20149110 was written to document discolored oil in the 23 component cooling pump outboard oiler. The notification stated that a lube oil sample would be taken but added that the discoloration may be associated with dye used in the oil. The inspector identified that PSEG had not updated the notification to indicate that the sample had, in fact, been taken with satisfactory results.

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

Section 1R12.1 describes a finding for ineffective problem evaluation that rendered a containment fan cooler unit outlet valve inoperable. Results obtained during an inservice valve stroke test significantly changed from a prior test in that the valve slowed from approximately 14 seconds to approximately 19 seconds. Engineers reasoned that a previous known phenomena had occurred with this valve, yet the actual symptoms were not as described in the evaluation. Engineers also did not consider the results of a recent heat exchanger performance test that could have also questioned a change in the valve's performance.

Section 4OA3.3 describes a finding for untimely corrective actions that allowed portions of the Unit 1 auxiliary building to remain without adequate ventilation and filtration capabilities in excess of the technical specification allowed outage time. PSEG engineers identified no exhaust flow in a portion of the auxiliary building exhaust ventilation system. Control room operators were notified but did not recognize the technical specification applicability.

4OA3 Event Followup (71153 - 3 samples)

1. (Closed) LER 50-311/03-003-00, Manual Reactor Trip Due to Dropped Control Rod

On November 22, 2003, while withdrawing control rod banks in preparation for Unit 2 startup physics testing, control room operators observed that rod 2D5 did not move. Technicians determined a blown power supply fuse caused the rod to be immovable. Further troubleshooting did not identify related circuit problems and PSEG concluded that the fuse failed due to infant mortality.

PSEG resumed control rod withdrawals and physics testing on November 22 at 10:13pm. At 5:04am on November 23, control rod 1D4 dropped. Control room operators manually tripped the Unit 2 reactor at 5:19am in response to the abnormal control rod configuration during physics startup testing. Plant response to the manual reactor trip was normal.

This event was also described in NRC Inspection Report 50-272/03-09, 50-311/03-09, Section 1R17 Permanent Plant Modifications as a Green, self-revealing, NCV. This LER was reviewed by the inspector and no additional findings of significance or violations of NRC requirements were identified. PSEG entered the reactor trip into its corrective action program as notification 20167830. This LER is closed.

2. (Closed) LER 50-311/04-001-00, Failure to Take Proper Compensatory Containment Air Samples

On February 13, 2004, PSEG identified that representative samples of the Unit 2 containment atmosphere had not been taken in accordance with technical specification action statement 3.4.7.1. PSEG found that procedural noncompliance by the chemistry technicians caused three consecutive samples to be improperly drawn, resulting in a period of approximately 36 hours where no valid sample of containment atmosphere existed. PSEG obtained a valid sample shortly after identifying the problem and containment conditions were verified to be normal. No new findings were identified in the inspector's review of this issue. This finding constitutes a violation of minor significance that is not subject to enforcement action in accordance with Section IV of the NRC's Enforcement Policy. The licensee documented the problem in notification 20177701. This LER is closed.

3. (Closed) LER 50-272/03-005-00, Condition Prohibited by Technical Specifications: Auxiliary Building Ventilation System Fire Damper Found Out of Position

a. Inspection Scope

The inspectors reviewed the LER and notifications 20175113 and 20175367, which documented this event in the corrective action program, to verify that the cause of the degraded Unit 1 ABV system fire damper was understood and that corrective actions were reasonable. The inspectors interviewed operators, system engineers, and fire protection technicians to understand the details of the ABV problem discovery and to also understand the workings of the automatic fire dampers. Portions of the auxiliary building were isolated from the ABV exhaust when two fire dampers inadvertently isolated. The closed dampers were not annunciated in the main control room. ABV lineup problems were discovered on January 23, 2004, during an ABV system walkdown by system engineers for an unrelated problem. The root cause of the ABV lineup problem was two closed fire dampers.

b. Findings

Introduction. A Green self-revealing finding for failure to follow technical specification requirements was identified.

Description. PSEG determined that the two fire dampers inadvertently closed and did not annunciate due to improper seating of a thermal actuation link in combination with failure of the closure mechanism. The dampers were last tested in November 2003. In November 2003, one of the two dampers would not trip closed when its thermal latch was heated for test purposes. PSEG surmised that although it did not trip, the heat applied may have sufficiently loosened the latch such that subsequent thermal or vibration effects may have totally released the latch closing the damper. The other damper had tested satisfactorily in November 2003, but PSEG believed it possible that the damper was not properly reseated and the same mechanism of unlatching due to thermal or vibration effects tripped the damper closed. At the time of inspector review,

PSEG had not completed its validation of the damper closure mechanism failure and had been providing compensatory fire watches for the two affected dampers.

The inspectors did not identify a performance deficiency associated with the November 2003 fire damper testing. However, the inspectors did identify a performance deficiency in PSEG's initial identification of the ABV issue. On January 23, 2004, PSEG engineers identified and reported to control room operators that a portion of the ABV exhaust ductwork and supporting emergency core cooling system areas had no airflow. Control room operators were not prompt to enter TS 3.7.7.1.b for the inoperable auxiliary building exhaust air filtration system when conditions existed for no air filtration in portions of the auxiliary building. Two days elapsed while PSEG worked through the ABV issue. TS 3.7.7.1.b. required the ABV filtration be restored within 24 hours or be in at least hot standby within the next 6 hours. ABV was restored to an operable status on January 25, 2004, when the two fire dampers were opened.

Analysis. The performance deficiency associated with this issue is inadequate problem evaluation. Control room operators did not recognize that no airflow in a portion of auxiliary building ventilation exhaust duct work required expeditious resolution and entry into TS 3.7.7.1.b. The inspectors determined that the finding was associated with the configuration control attribute of the Barrier Integrity cornerstone and affected the cornerstone objective of assuring physical design barriers protect the public from releases caused by accidents. Therefore, the finding is greater than minor. This issue screened to Green in phase 1 of the SDP because only the auxiliary building radiological barrier function was involved.

Enforcement. Salem Unit 1 TS 3.7.7.1.b requires the auxiliary building charcoal adsorber bank be restored to an operable status within 24 hours or be in at least hot standby within the next 6 hours. Contrary to the above, on January 23, 2004, portions of the auxiliary building were identified as isolated from the ABV exhaust duct and were not restored and capable of being lined-up to the charcoal adsorber until January 25, 2004. Because the failure to maintain operable the ABV charcoal adsorber bank was determined to be of very low safety significance and has been entered into PSEG's corrective action program (notifications 20175113 and 20175367), this violation is being treated as an NCV, consistent with Section VI.A of the NRC Enforcement Policy: NCV 50-272/04-02-05, Auxiliary Building Ventilation Not Promptly Restored.

4OA4 Cross Cutting Aspects of Findings

Section 1R19 describes inadequate maintenance practices that rendered an auxiliary building high energy line break blowout panel inoperable and a green finding that was related to human performance.

4OA5 Other

Temporary Instruction 2515/154, Spent Fuel Material Control and Accounting at Nuclear Power Plants. Phase I and Phase II inspection of 2515/TI-154 was completed during

this inspection period. Appropriate documentation was provided to NRC management as required. No findings of significance were identified.

NRC Review: PSEG Independent Assessment Team (IAT). On March 23, a review was completed to assess the adequacy of PSEG's IAT interview process. PSEG formed the IAT to conduct an in-depth assessment of the work environment for raising and addressing safety concerns at Salem and Hope Creek. As stated in PSEG's February 27 letter (ADAMS Accession: ML040580600), the IAT would be utilizing several sources of information in its assessment efforts, including interviews with personnel at Salem, Hope Creek, and PSEG corporate. At the completion of the review, issues regarding interview population demographics and size; and the availability of the IAT to interested parties (i.e., "open door policy") was discussed with PSEG management. In response to the NRC's observations, PSEG expanded its interview population and established an "open door" policy for the IAT that was communicated to personnel at Salem and Hope Creek.

(Closed) URI 50-272/03-09-06: Unit 1 Emergency Diesel Generator (EDG) Failure to Stop on Demand

This unresolved item was opened to follow up PSEG troubleshooting activities related to the failure of the Unit 1 EDG to stop when the local switch was placed in the 'Stop' position, following its monthly surveillance test. The inspector reviewed the scope and results of the troubleshooting activities and concluded that no violations of NRC requirements had occurred. This item is closed.

4OA6 Meetings, Including Exit

NRC/PSEG Management Meeting To Discuss Work Environment

The NRC conducted a meeting with PSEG on March 18 to discuss the work environment at the Salem and Hope Creek power plants. During the meeting the NRC discussed the contents of its letter dated January 28, Work Environment for Raising and Addressing Safety Concerns at the Salem and Hope Creek Generating Stations (ADAMS Accession:ML040280476). PSEG provided a synopsis and status of activities described in their letter dated February 27, PSEG Plan for Assessing and Improving the Work Environment to Encourage Identification and Resolution of Issues (ADAMS Accession:ML04580600). The meeting occurred at the Holiday Inn Select Bridgeport, New Jersey and was open for public observation. A copy of the slides presentation can be found in ADAMS under accession number ML040830072 and ML040790261.

Exit Meeting

On April 15, 2004, the inspectors presented their overall findings to members of PSEG management led by Messrs. Mike Brothers, David Garchow, and Carl Fricker.

ATTACHMENT: SUPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee personnel:

M. Conroy, Senior Engineer (Maintenance Rule Program Manager)
R. Fisher, Supervisor, Access Authorization
R. Gary, Radiation Protection Manager
F. Hummel, System Engineer
M. Ivanick, Security Operations Coordinator
D. Kolasinski, System Engineer
K. Meyers, Nuclear Quality Assurance Auditor - Operating Experience
K. Miller, System Engineer
D. Naik, System Engineer
T. Straub, Emergency Services Manager
R. Villar, Senior Engineer, Licensing
S. Zeigler, ALARA Specialist
R. Yewdall, Licensing

LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

50-272/04-02-01	URI	Failure of 11 Traveling Water Screen Due to Ice Buildup (Section 1RO1)
50-311/04-02-03	URI	Failure of 25 Traveling Water Screen Due to Inadequate Lubrication (Section 1R12.2)

Opened/closed

50-272/04-02-02	NCV	Failure to Adequately Evaluate a CFCU Service Water Valve Anomaly (Section 1R12.1)
50-311/04-02-04	NCV	Improper Repair to Safety-Related Component (Section 1R19)
50-272/04-02-05	NCV	Auxiliary Building Ventilation Not Promptly Restored (Section 4OA3.3)
50-311/03-003-00	LER	Manual Reactor Trip Due to Dropped Control Rod (Section 4OA3.1)

50-311/04-001-00	LER	Failure to Take Proper Compensatory Containment Air Samples (Section4OA3.2)
50-272/03-005-00	LER	Condition Prohibited by Technical Specifications: Auxiliary Building Ventilation System Fire Damper Found out of Position (Section 4OA3.3)

Closed

50-272/03-09-06	URI	Unit 1 Emergency Diesel Generator (EDG) Failure to Stop on Demand (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 1R12: Maintenance Effectiveness

Report #80057735, 2003 10CFR50.65(a)(3) Periodic Assessment (September 2001 - June 2003)
NC.NA-AP.ZZ-0016(Q), Monitoring the Effectiveness of Maintenance, 12/24/01
SH.ER-DG.ZZ-0001(Q), Preventable and Repeat Preventable System Functional Failure Determination, May 2001
SH.ER-DG.ZZ-0002(Q), Maintenance Rule (a)(1) Evaluations and Goal Monitoring, 12/3/01
SH.ER-SE.ZZ-0009(Q), System Specific Performance Criteria, 6/1/99
SH.ER-SE.ZZ-0014(Q), Maintenance Rule Scoping, 6/24/99
SE.MR.SA.01, Maintenance Rule System Function and Risk Significance Reference, 4/23/03
SE.MR.SA.02, System Function Level Maintenance Rule Scoping vs. Risk Reference, 4/23/03
Lesson Plan NECNRULEIMPL, Maintenance Rule Implementation Training
Lesson Plan NECDMAINTRLC, Maintenance Rule Overview Training

System Health Reports/MR Basis Documents
Auxiliary Feedwater System
Gas Turbine
Residual Heat Removal System
Emergency Diesel Generators

Notifications/Evaluations: 20167133, 20167134, 70016036, 70027584, 70029886, 70031717, 70032685, 70032722, 70032723, 70032774, 70032791, 80057735, 80063522, 80063885, 80063886, 80063887, 80063888

Performance Indicator Verification (71151)

PSE&G Salem/Hope Creek Security IDS/CCTV Performance Indicator Report - 1st Quarter 2003 through 1st Quarter 2004
PSE&G Salem/Hope Creek Fitness For Duty Performance Indicator Report 1st Quarter 2003 through 4th Quarter 2003

LIST OF ACRONYMS

ABV	Auxiliary Building Ventilation
AFW	Auxiliary Feedwater
ALARA	As Low As Is Reasonably Achievable
CFCU	Containment Fan Cooler Unit
CFR	Code of Federal Regulations
CVC	Chemical Volume Control
EDG	Emergency Diesel Generator
EOP	Emergency Operating Procedures
FHB	Fuel-handling Building
FSAR	Final Safety Analysis Report
HELB	High Energy Line Break
HP	High Pressure
IAT	Independent Assessment Team
IST	Inservice Testing
NCV	Non-cited Violation
NEI	Nuclear Energy Institute
NRC	Nuclear Regulatory Commission
OD	Operability Determination
PARS	Publicly Available Records
PIs	Performance Indicators
PM	Preventive Maintenance
PMT	Post Maintenance Testing
PSEG	Public Service Electric Gas
RCA	Radiologically Controlled Area
RP	Radiation Protection
RWP	Radiation Work Permit
SCBA	Self-contained Breathing Apparatus
SDP	Significance Determination Process
SWP	Service Water Pump
SWTWS	Service Water Traveling Water Screen
TMODs	Temporary Modifications
TS	Technical Specifications
TWS	Traveling Water Screen