December 8, 2000

Mr. Harold W. Keiser
President and Chief Nuclear Officer
PSEG Nuclear Limited Liability Company
Post Office Box 236
Hancocks Bridge, NJ 08038

SUBJECT: NRC's SALEM NUCLEAR GENERATING STATION - NOS. 05000272/2000-009, 05000311/2000-009

Dear Mr. Keiser:

On November 11, 2000, the NRC completed an inspection of your Salem Units 1 and 2 reactor facilities. The enclosed report documents the preliminary inspection findings which were discussed on November 22, 2000, with PSEG Nuclear management led by Mr. Martin Trum 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.

Based on the results of this inspection, the inspectors identified one issue of very low safety significance (Green) related to preventive maintenance on the auxiliary feedwater system. This issue was determined to involve a violation of an NRC requirement. However, because of its very low safety significance and because it has been entered into your corrective action program, the NRC is treating this issue as a non-cited violation, in accordance with Section VI.A.1 of the NRC's Enforcement Policy. If you deny this non-cited violation, you should provide a response with the basis for your denial, within 30 days of the date of this inspection report, 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 facility.

In accordance with 10 CFR 2.790 of the NRC's "Rules of Practice," a copy of this letter and its enclosure 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/NRC/ADAMS/index.html (the Public Electronic Reading Room).

Sincerely,

/RA/

Glenn W. Meyer, Chief
Projects Branch 3
Division of Reactor Projects

Enclosure: Inspection Report 05000272/2000-009, 05000311/2000-009

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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:	05000272/2000-009, 05000311/2000-009
Licensee:	PSEG Nuclear LLC
Facility:	Salem Nuclear Generating Station, Units 1 & 2
Location:	P.O. Box 236 Hancocks Bridge, NJ 08038
Dates:	October 1 - November 11, 2000
Inspectors:	Scott A. Morris, Senior Resident Inspector F. Jeff Laughlin, Resident Inspector Joseph T. Furia, Senior Health Physicist Kenneth S. Kolaczyk, Reactor Inspector Leonard J. Prividy, Senior Reactor Engineer Paul Kaufman, Senior Reactor Inspector Keith Young, Reactor Inspector Michael Modes, Senior Reactor Inspector
Approved By:	Glenn W. Meyer, Chief, Projects Branch 3 Division of Reactor Projects

Summary of Findings

IR 05000272-00-09, IR 05000311-00-09, on 10/01-11/11/2000, Public Service Electric Gas Nuclear, Salem Units 1 and 2. Permanent plant modifications.

The inspection included six weeks of resident inspection, and inspections of occupational radiation safety, inservice inspection, and permanent plant modifications by regional inspectors. This inspection identified one green finding, which was a non-cited violation. The significance of findings is indicated by their color (Green, White, Yellow, or Red) using IMC 0609 “Significance Determination Process” (SDP). Findings for which the SDP does not apply are indicated by “no color” or by the severity level of the applicable violation.

A. Inspector Identified Findings

Cornerstone: Mitigating Systems

- GREEN. PSEG Nuclear did not perform the specified preventive maintenance (PM) tasks for the new equipment associated with the turbine driven auxiliary feedwater pump enclosure modification at both units. This problem resulted in a credible impact on safety-related equipment which could have affected the availability and reliability of the auxiliary feedwater system. The failure to properly perform PM tasks for the new equipment associated with modification 2EC-3522 as required by Procedure NC.WM-AP.ZZ-0003(Q), Rev. 0, “Regular Maintenance Process,” was considered to be a non-cited violation of 10 CFR 50, Appendix B, Criterion V, “Instructions, Procedures, and Drawings.”

  The issue was determined to be of very low risk significance using the Significance Determination Process phase 1 screening because no actual equipment failures were attributed to the missed PMs. (Section 1R17).

B. Licensee Identified Findings

Violations of very low significance which were identified by PSEG Nuclear were reviewed by the inspector. Corrective actions, taken or planned by PSEG Nuclear, appeared reasonable. These violations are listed in section 40A7 of this report.

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Report Details

SUMMARY OF PLANT STATUS

Unit 1 began the period at 100% power and remained there until October 4, 2000, when operators reduced power to 60% to add oil to a reactor coolant pump bearing oil reservoir. They restored the unit to full power on October 5, where it generally remained for the rest of the report period.

Unit 2 began the period at 89% power in an end-of-cycle coast-down prior to eleventh refueling outage (2R11). The refueling outage started when the main generator output breaker was opened on October 5. The unit was in Mode 3 in preparation for reactor start-up when the period ended.

1. REACTOR SAFETY
(Cornerstones: Initiating Events, Mitigating Systems, and Barrier Integrity)

R02 Evaluations of Changes, Tests, or Experiments

a. Inspection Scope

The inspectors reviewed the safety evaluations (SEs) described below. They verified that changes to the facility or to the procedures as described in the Updated Final Safety Analysis Report (UFSAR) were reviewed and documented in accordance with 10 CFR 50.59. The SEs were selected from the changes performed during the last two years, taking into consideration the safety significance of the change, risk to the structures, systems, and components affected, and impact on the three reactor safety cornerstones. The inspectors also reviewed PSEG Nuclear's identification and resolution of problems related to SEs and associated changes.

- DCP 1EC-3637 — Replacement of 125/250 VDC Switchgear
- DCP 1EE-0430 — Setpoint Change for the Fire Protection Jockey Pump Start Switch
- DCP 1EC-3729, Rev. 1 — Replacement of Pressurizer Safety Valves 1PR3, 1PR4, 1PR5
- DCP 80004565 — SSPS and ESF Design Changes to Allow Dual Train Unavailability During Modes 5 and 6
- DCP 80005323 — 1R19 - Steam Generator Blow Down Sample Line Pressure Regulator
- DCP 80008505 — 4KV/125VDC Controls Circuits Modification
- DCP 80008741 — 2PR1 and 2PR2 Control Circuit Modification
- DCP 80008745 — Appendix R, 230 VAC Vital SWGR/MCC Coordination
- DCP 80001108 — Manual/Automatic Purge and Pressure/Vacuum Relief Isolation with Both Trains of the Solid State Protection System Out-of-Service
- DCP 80013749 — Mid-loop Transmitter Replacement Project
- DCP 2EC-3567-1 — Replacement of 125/250 VDC Switchgear Breakers
- T-mod 00-016 — Hot Taps for Bypass Line Around Gagged 2ST901 Valve
- DCP 80006697 — 21 AFW Pump Runout Protection

- SE-99-014 — Use of Outage Equipment Hatch during Refueling
- T-mod 00-005 — 13 Service Water Strainer for Continuous Backwash
- S-1-SW-MEE-1359, Rev. 0 — Evaluation of Aggregate Performance of Salem 1 CFCUs
- CP 2EE-0337 — Replacement of Demineralizer Check Valve 2DR7
- SC.CH-AD.RC-1135(Q) — Boric Acid Addition to Accumulators

The inspectors also reviewed a sample of changes, tests and experiments, as described below, for which PSEG Nuclear determined that a SE was not required. The inspectors performed this review to verify that the threshold for performing SEs was consistent with 10 CFR 50.59.

- SC.MD-CM.CN-0001, Rev. 12 — Generator Feed Pump Disassembly, Inspection, Repair and Reassembly
- SC-RCP001-01 & 03 — Westinghouse Calculations Computerized Scaling Manual for Delta T and Average Temperature
- SH.RA-ST.ZZ-0106, Rev. 1 — Visual Inspection of Containment Structural Integrity
- S1/S2.IC-SP.RC-0003(Q), Rev. 6 — Reactor Head Instrumentation Removal and Installation
- S1.RA-ST.SJ-0002(Q), Rev. 2 — In-service Testing 12 Safety Injection Pump Acceptance Criteria
- S1.RA-ST.SW-0002, Rev. 2 — In-service Testing 12 Service Water Pump Acceptance Criteria
- S2.MD-ST.4KV-0008(Q), Rev. 8 — Surveillance Testing of 4KV Breaker Cubicle 2F3D Relays
- S2.OP-ST.CVC-0007, Rev. 13 — In-service Testing Chemical and Volume Control Valves Modes 5 and 6
- 1EE-0386, Rev. 0 — Addition of Appendix R, 8 Hour Battery Pack Emergency Lighting
- 1EE-0435, Rev. 0 — Add High Limit for RC Loop Delta “T” Signal
- 2EE-0203, Rev. 0 — Replacement of Control Power Transformer Fuses in Vital 230 Volt Pan Units
- 80003766, Rev. 0 — Removal of 52 SM/LS Contact 5-6 From 4KV and 13KV Circuit
- ECA 1EE-0406, Rev. 0 — Installation of Clevis Weldments for the Outage Equipment Hatch

b. Observations and Findings

No findings of significance were identified.

R08 Inservice Inspection Activities

a. Inspection Scope

During 2R11 the inspectors observed portions of nondestructive examination (NDE) activities performed on the Unit 2 steam generators and the safety injection system. Additionally, the inspectors reviewed several procedures and reports associated with eddy current inspection of the Salem steam generators, including the degradation assessment report, a signal/noise ratio study, and eddy current examination procedures. Finally, the inspectors reviewed several ASME Section XI code repair/replacement packages on Units 1 and 2, as well as radiographs on the following Unit 1 components: S1-VEN-2-1-A, S1-VEN-2-2-A, and S1-14SW57-TD-3813-1.

The steam generator review included: (1) interviewing PSEG Nuclear and contract eddy current NDE personnel to assess their knowledge of steam generator degradation phenomena, (2) reviewing samples of eddy current inspection data obtained from several tubes, and (3) verifying that approved probes were used to acquire eddy current inspection data. The inspectors reviewed data from the following tubes:

Steam Generator	Row	Column
21	29	71
21	22	30
22	22	30
22	42	65
23	2	3
23	3	29
23	2	45

Regarding the NDE performed on the safety injection system, the inspectors verified that the technicians used proper technique when performing the examinations, reported indications when necessary, and calibrated the ultrasonic testing instruments in accordance with PSEG Nuclear procedures. The inspectors observed both ultrasonic and liquid penetrant NDE on weld 6-SJ-1222-8.

PSEG Nuclear did not perform any non-code repairs on safety-related equipment at Units 1 and 2 over the last twelve months that required NRC relief from the ASME code. Therefore, non-code repair activities were not reviewed during this inspection.

Finally, several evaluations associated with findings from the NDE program were reviewed.

b. Issues and Findings

No findings of significance were identified.

R13 Maintenance Risk Assessments and Emergent Work Control

a. Inspection Scope

The inspectors reviewed the immediate actions taken in response to the October 2 failure of the 16 service water pump 4KV breaker to close. This failure occurred when operators attempted to start the pump during routine surveillance activities. The inspectors observed breaker troubleshooting activities and discussed the initial review with the system manager.

The inspectors observed and assessed actions to resolve emergent failures of the 13 auxiliary building ventilation exhaust fan and the 12 chill water pump. They discussed these issues with operations and engineering personnel, and verified that the weekly risk assessment was updated and that appropriate actions were taken to minimize risk.

b. Issues and Findings

No findings of significance were identified.

1R17 Permanent Plant Modifications

a. Inspection Scope

The inspectors reviewed the permanent plant modifications listed:

- DCP 1EC-3446 — Component Cooling Heat Exchanger (CCHX) Flow Restricting Orifices for 11CCHX
- DCP 1EC-3637 — Replacement of 125/250 VDC Switchgear
- DCP 1EC-3729 — Replace 1PR3, 4 and 5 Valves
- DCP 2EC-3405 — Flow Restriction Orifice for 21 CCHX
- DCP 2EC-3567-1 — Replacement of 125/250 VDC Switchgear Breakers
- DCP 1EE-0386 — Appendix R Emergency Lights
- DCP 1EE-0430 — Setpoint Change for Fire Protection Jockey Pump Start Switch
- DCP 1EE-0435 — Add High Limit for RC Loop Delta “T” Signal
- DCP 2EE-0203 — Control Circuit Fuse in Pan Unit
- DCP 80001108 — Manual/Automatic Purge and Pressure/Vacuum Relief Isolation with Both Trains of the Solid State Protection System Out-of-Service
- DCP 80003766 — Install Jumper Across 4KV Magneblast 52 SM/LS Switch
- DCP 80004565 — SSPS and ESF Design Changes to Allow Dual Train Unavailability During Modes 5 and 6
- DCP 80008505 — 4KV/125VDC Controls Circuits Modification
- DCP 80008741 — Modification of PORV Control Circuits
- DCP 80008745 — Appendix R, 230 VAC Vital Switchgear/MCC Coordination

• DCP 80006697	21 AFW Pump Runout Protection
• ECA 1E-0406	Installation of the Clevis Weldments for the Outage Equipment Hatch
• DCP 2EC-3590	Service Water System - CFCU Thermal Overpressure Protection
• DCP 2EC-3522	Unit 2 Turbine Driven Auxiliary Feedwater Pump Enclosure Damper Modification

The plant modifications were either completed during the last two years or were scheduled to be installed during 2R11. Two of the modifications for the Unit 2 outage were deferred. The selection was based on the risk significance of the system being modified and the impact of the modification on the reactor safety cornerstones: initiating events; mitigating systems; and barrier integrity. The modifications included component replacements, equivalency evaluations, and setpoint changes. The inspectors examined the modifications and post-modification testing results for system interactions and structure, system, and component performance. The inspectors determined the modification's impact on system availability, reliability, and functional capability by reviewing the affected parameters associated with the modification. The inspectors reviewed calculations, licensing, and design basis documents to ascertain if they were updated in accordance with the modification. The inspectors interviewed design engineers, system engineers, system managers, and licensing personnel familiar with the modification. The inspectors also performed walkdowns of selected modifications to verify installation and material condition of the modification.

b. Observations and Findings

.1 2EC-3522 - Unit 2 Turbine Driven Auxiliary Feedwater Pump (TDAFWP) Enclosure Damper Modification

This modification, which affected the mitigating system cornerstone, removed a damper from the TDAFWP enclosure and added two blow-out panels, an automatic damper, and two temperature switches. These changes were made to enhance the operation of the room cooler that supplies the TDAFWP enclosure, providing additional protection for the enclosure and adjacent motor driven AFW pumps in the event of a steam-line break. A similar modification had been implemented in Unit 1. The modifications in both units were made operational in 1996/1997. After conducting several walkdowns of the installed changes and reviewing the modification closeout documentation, which included Calculation No. 6S0-1106-005, Rev. 0, "Qualification of AFW Pump Room Enclosure for Damper and Blowout Panel Modifications," the inspectors noted the following problems:

- To properly maintain the equipment in the modified design, PSEG Nuclear personnel initiated PM change request forms S2.ABV.PMCR 96340 and 96352. This initiated actions to evaluate and develop recurring tasks (RTs) for the blow-out panel hardware, the new damper, temperature switches, and associated equipment. When the inspectors requested the results of the last PM items performed on the new blow-out panels, PSEG Nuclear personnel stated that they had failed to enter RTs into the work control system for the new equipment associated with this modification. Entries of such PM items were required by Procedure NC.WM-AP.ZZ-

0003(Q), Rev. 0, “Regular Maintenance Process.” A preliminary evaluation determined that the RT numbers and PMs for the new equipment were not transferred from the old work management system (MMIS) into the new system (SAP) during conversion in 1999. PSEG Nuclear issued notification 20044775 on October 25, 2000, to address this problem.

- Two spring plunger mechanisms are attached to each 24"X24" blow-out panel with two panels installed in each TDAFWP enclosure. The springs pre-load the blow-out panel such that a steam explosion can exert the final force needed to explode two fasteners, causing the blow-out panel to open and release steam to the adjacent pipe chase. In Calculation No. 6S0-1106-005 where the blow-out panel compression springs were being sized, the inspectors noted that the designer made the comments to “replace spring every 18 months by recurring task to overcome relaxation concerns”. However, PSEG Nuclear personnel stated that the frequency to replace spring plungers would be 54 months. Since spring relaxation will cause loss of pre-load and possibly create a malfunction of the blow-out panels, the inspectors questioned the technical basis for this change in frequency.

- Based on the inspectors’ walkdown of the Unit 1 and 2 TDAFW pump enclosures with the AFW system engineer, they noted that a small amount (about ½") of red rubber gasket material was missing from one of the blow-out panels in Unit 2. They also detected air flow past the blow-out panel at this location. The design in 2EC-3522 required red rubber gasket material to be completely surrounding the blow-out panel. PSEG Nuclear initiated notification 20044894 to address these items.

In light of the above noted problems, the inspectors requested PSEG Nuclear engineers to determine if the TDAFWP enclosure would function as designed in the event of a steam-line break. After further review subsequent to the inspectors’ onsite activities, the engineers stated that the TDAFWP enclosures in both units were fully functional based on the following:

- Contrary to the information provided earlier in the inspection that no RTs were performed, the 18-month PM task to inspect the blow-out panels in Unit 2 was actually completed. This activity was started on October 15 and completed satisfactorily on October 28, 2000. Design engineering personnel inspected the Unit 1 blow-out panels and judged them to be acceptable. Regarding the inspectors’ comment on the 18 versus 54 month frequency for the spring plunger replacement, PSEG Nuclear concluded, based on engineering judgment and discussions with the vendor, that 18 months was overly conservative and 54 months was acceptable. The licensee also judged that the missing gasket material did not cause a functionality problem with the Unit 2 blowout panels.

- The inspectors also had several discussions with PSEG Nuclear personnel during the week of November 6 concerning the PMs that were intended to be performed on the new dampers, 1(2) ABS20, and temperature switches, 1(2) TD18146 and 1(2) TD18147. RTs should have been created to perform an 18-month PM to inspect and calibrate the temperature switches and perform a functional test to ensure damper ABS20 closes when the temperature was above the setpoint. The RT was to include the switches, damper, damper operator and the solenoid operated valves, 1(2)SV1093 and 1(2)SV1094, which port air to the damper operators. PSEG Nuclear stated that the RTs for these PM items had not been scheduled and had not been performed since this modification had been implemented in both units. However, based on a visual inspection, it was PSEG Nuclear's engineering judgment that this equipment was functional.

The inspectors concluded that the failures to perform the required PMs for the new equipment associated with the modification for the TDAFWP enclosure resulted in a credible impact on safety-related equipment and that this issue could affect the availability and reliability of the AFW system. The inspectors noted that PSEG Nuclear acknowledged that this issue was an additional example of problems concerning PMs for other safety-related equipment. Since PSEG Nuclear determined that the equipment remained operable and no actual equipment failures were attributed to the missed PMs, this issue had very low risk significance according to the Significance Determination Process phase 1 screening. The failures to properly schedule and perform PM tasks for the new equipment associated with Modification 2EC-3522 as required by Procedure NC.WM-AP.ZZ-0003(Q), Rev.0, "Regular Maintenance Process," was considered to be a non-cited violation (NCV) of 10 CFR 50, Appendix B, Criterion V, Instructions, Procedures, and Drawings. The issues associated with this violation are in the corrective action program as listed above. **(NCV 05000272&311/ 2000-009-01)**

R19 Post Maintenance Testing

a. Inspection Scope

The inspectors observed portions of post maintenance testing (PMT) activities and reviewed PMT data following planned and emergent work on the 22 auxiliary feed water pump. The inspectors verified that test activities adequately assured system operability and that the appropriate acceptance criteria had been met.

b. Issues and Findings

No findings of significance were identified.

R20 Refueling and Outage Activities

a. Inspection Scope

During 2R11 the inspectors performed numerous verifications of decay heat removal parameters to verify proper system operation. The inspectors also verified proper inventory and reactivity control, electrical system status, and containment integrity. The inspectors observed reduced inventory and mid-loop operations and confirmed that the plant configuration was in accordance with their Generic Letter 88-17 commitments. They also observed portions of the vacuum filling of the reactor coolant system and refueling activities from the refueling bridge in containment and the fuel handling building. Lastly, the inspectors observed portions of the plant start up and heat up activities, and verified on a sampling basis that technical specifications, license conditions, and administrative procedures were met prior to mode changes.

The inspectors also reviewed the November 7 event, in which the 21 steam generator had a high level which resulted in a feedwater isolation. The plant was in mode 4 at the time of the event which was caused by improper operation of the feedwater regulating valve. Plant systems responded as expected, and operators made the required four-hour NRC notification. This event will be dispositioned upon review of the associated Licensee Event Report.

b. Issues and Findings

No findings of significance were identified.

R22 Surveillance Testing

a. Inspection Scope

The inspectors observed a portion and reviewed the results of the October 4 surveillance test on the 13 component cooling water pump. The inspectors verified that test results met the appropriate technical specification acceptance criteria and the pump was capable of performing its intended safety function.

b. Issues and Findings

No findings of significance were identified.

2. RADIATION SAFETY

Occupation Radiation Safety [OS]

OS1 Access Control

a. Inspection Scope

The inspectors reviewed the access control program during 2R11 by examining the controls established for three exposure significant areas, including postings, markings, control of access, dosimetry, surveys, and alarm set points. Areas selected were located throughout the radiologically controlled area (RCA) and included the area inside the bio-shield which contains the primary side access to the steam generators. Controls reviewed included key control for locked high radiation areas, use of radiation work permits to control access to radiologically significant areas, and pre-job radiological briefings.

The inspectors observed radiation worker performance with respect to stated radiation protection work requirements. This also included verification of radiological controls, such as adequacy of surveys and radiation protection technician coverage. The inspectors observed numerous personnel working in radiologically significant areas in support of the refueling outage. The inspectors reviewed the radiation work permits for these entries, attended the pre-job briefings by the radiation protection staff, observed controls present for access to posted high radiation areas, reviewed alarm set points, and reviewed calculations of potential internal exposures. Specific jobs reviewed and observed included: 21 reactor coolant pump work including removal of the pump seal, in-service inspection (ISI) on valves and piping connecting to the 23 and 24 steam generators, set-up for steam generator platform work and eddy current testing, and reactor disassembly.

The inspectors reviewed recent condition reports for radiological issues related to radiological worker or radiation protection technician performance. Reports reviewed included #20041300 (workers briefed for entry into Unit 2 containment, but worked in the Unit 1 containment) and #20038469 (hot particle contamination on skin of lower leg). The review focused on observable patterns traceable to similar causes.

b. Issues and Findings

No findings of significance were identified.

OS2 ALARA Planning and Controls

a. Inspection Scope

The inspectors reviewed 2R11 work performance, including engineering controls to achieve dose reductions, use of low dose waiting areas, on-job supervision provided to workers, and individual exposures from selected work groups. The inspectors also evaluated engineering controls for dose reductions and an analysis of source term reduction plans.

The inspectors observed radiation workers and radiation protection technicians during high dose rate and/or high exposure jobs to determine if the training/skill level was sufficient for the radiological hazards. Additionally, the inspectors reviewed the assumptions and basis for the various job estimates, including the methodology utilized for estimating job-specific exposures.

b. Issues and Findings

No findings of significance were identified.

4. OTHER ACTIVITIES [OA]

OA3 Event Follow-up

a. Inspection Scope

The inspectors reviewed the October 9 toxic gas (hydrazine) release to the Unit 1 turbine building which resulted in the declaration of an unusual event (UE). This event was caused by personnel error, but had no safety consequences because the hydrazine toxic limits were not exceeded. The operators correctly declared the UE in accordance with station procedures and made timely notifications to the NRC and local officials.

b. Issues and Findings

No findings of significance were identified.

OA5 Other

(Closed) URI 05000272&311/2000-007-01: The inspectors reviewed this previously identified URI concerning pre-conditioning of the emergency diesel generators (EDGs) before monthly surveillance tests (STs). The inspectors determined that although there was no sound basis for performing the EDG lube immediately before the ST, this issue was minor due to no evidence that potential maintenance problems would be masked, and therefore not evaluated, because of this practice. PSEG Nuclear wrote notification 20047202 to address this issue and the inspectors concluded that corrective actions were adequate. Therefore, this URI was closed.

OA6 Management Meetings

a. Exit Meeting Summary

On November 22 the inspectors presented their preliminary findings to members of PSEG Nuclear management led by Mr. Martin Trum. PSEG Nuclear management acknowledged the findings presented, but noted that the NRC interpretation of “credible impact” in the instance of the finding and NCV on the AFW modification (Section 1R17) appeared to be overly conservative. They did not contest any other of the inspectors' conclusions. Additionally, they stated that none of the information reviewed by the inspectors was considered proprietary.

b. PSEG Nuclear/NRC Management Meeting

On October 27 Dr. Richard Meserve, NRC Chairman, and Mr. Hub Miller, Region I Administrator, met with members of PSEG Nuclear management, discussed regulatory issues during a working lunch, toured the Salem and Hope Creek plants, and answered questions from the media.

OA7 Licensee Identified Violation. The following finding of very low significance was identified by PSEG Nuclear and is a violation of NRC requirements which meets the criteria of Section VI of the NRC Enforcement Policy, NUREG-1600, for being dispositioned as a non-cited violation (NCV).

NCV 05000311/2000-09-02:

Plant Procedure IOP-6 specifies that a degassification evolution be performed on the primary coolant during a shutdown, via purging the hydrogen cover gas in the volume control tank with nitrogen. The cover gas in the volume control tank was not purged with nitrogen during shutdown on October 6, 2000, as described in Notification 20042531. This resulted in PSEG Nuclear personnel having to perform a second chemically-induced crud burst, resulting in increased dose rates on various pipes and components located inside the containment bio-shield.

SUPPLEMENTAL INFORMATION

a. Key Points of Contact

Sam Jones, Maintenance Team #3 Department Lead
John Robertson, Operations Manager
Steven Mannon, System Engineering Manager
Frank Soens, Assistant Operations Manager
Gabor Salamon, Licensing Manager
Larry Wagner, Work Management Department Lead

b. List of Items Opened, Closed, and Discussed

Opened/Closed

05000272&311/2000-009-01	NCV	Failure to schedule and perform preventive maintenance for a turbine driven auxiliary feedwater modification (Section 1R19)
05000311/2000-009-02	NCV	Failure to perform a nitrogen purge in accordance with procedures resulting in increased dose rates (Section 4OA7)

Closed

05000272&311/2000-007-01	URI	Potential pre-conditioning of emergency diesel generators prior to monthly surveillance tests. (Section 4OA5)

c. List of Documents Reviewed

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

Assessment Plan:

Steam Generator Tubing Degradation Assessment
EPRI Appendix H Technique Qualification

Procedures:

SC.SA-AP.ZZ-0042(Q), Rev. 0	Design Engineering

S2.SG-ST.RCE-0001(Q), Rev 3	Salem Unit 2 Steam Generator Eddy Current Examination

d. <u>List of Acronyms</u>

ALARA	As Low As Is Reasonably Achievable
2R11	Eleventh Refueling Outage
ASME	American Society of Mechanical Engineers
EDGs	Emergency Diesel Generators
ISI	In-service Inspection
NCV	Non-cited Violation
NDE	Nondestructive Examination
NRC	Nuclear Regulatory Commission
PMT	Post Maintenance Testing
PARS	Publicly Available Records
PSEG	Public Service Electric Gas
RCA	Radiologically Controlled Area
SDP	Significance Determination Process
STs	Surveillance Tests
UE	Unusual Event
URI	Unresolved Item

ATTACHMENT 1

NRC's REVISED REACTOR OVERSIGHT PROCESS

The federal Nuclear Regulatory Commission (NRC) recently revamped its inspection, assessment, and enforcement programs for commercial nuclear power plants. The new process takes into account improvements in the performance of the nuclear industry over the past 25 years and improved approaches of inspecting and assessing safety performance at NRC licensed plants.

The new process monitors licensee performance in three broad areas (called strategic performance areas): reactor safety (avoiding accidents and reducing the consequences of accidents if they occur), radiation safety (protecting plant employees and the public during routine operations), and safeguards (protecting the plant against sabotage or other security threats). The process focuses on licensee performance within each of seven cornerstones of safety in the three areas:

Reactor Safety

- Initiating Events
- Mitigating Systems
- Barrier Integrity
- Emergency Preparedness

Radiation Safety

- Occupational
- Public

Safeguards

- Physical Protection

To monitor these seven cornerstones of safety, the NRC uses two processes that generate information about the safety significance of plant operations: inspections and performance indicators. Inspection findings will be evaluated according to their potential significance for safety, using the Significance Determination Process, and assigned colors of GREEN, WHITE, YELLOW or RED. GREEN findings are indicative of issues that, while they may not be desirable, represent very low safety significance. WHITE findings indicate issues that are of low to moderate safety significance. YELLOW findings are issues that are of substantial safety significance. RED findings represent issues that are of high safety significance with a significant reduction in safety margin.

Performance indicator data will be compared to established criteria for measuring licensee performance in terms of potential safety. Based on prescribed thresholds, the indicators will be classified by color representing varying levels of performance and incremental degradation in safety: GREEN, WHITE, YELLOW, and RED. GREEN indicators represent performance at a level requiring no additional NRC oversight beyond the baseline inspections. WHITE corresponds to performance that may result in increased NRC oversight. YELLOW represents performance that minimally reduces safety margin and requires even more NRC oversight. And RED indicates performance that represents a significant reduction in safety margin but still provides adequate protection to public health and safety.

The assessment process integrates performance indicators and inspection so the agency can reach objective conclusions regarding overall plant performance. The agency will use an Action Matrix to determine in a systematic, predictable manner which regulatory actions should be taken based on a licensee's performance. The NRC's actions in response to the significance (as represented by the color) of issues will be the same for performance indicators as for inspection findings. As a licensee's safety performance degrades, the NRC will take more and increasingly significant action, which can include shutting down a plant, as described in the Action Matrix.

More information can be found at: http://www.nrc.gov/NRR/OVERSIGHT/index.html.