February 8, 2000

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

SUBJECT: NRC INSPECTION REPORT 05000272/1999011, 05000311/1999011

Dear Mr. Keiser:

On January 9, 2000, the NRC completed an inspection of your Salem 1 & 2 reactor facilities. The enclosed report presents the results of that inspection. The preliminary findings were presented to PSEG Nuclear management led by Messrs. L. Wagner and M. Kafantaris in an exit meeting on January 19, 2000.

NRC inspectors examined numerous activities as they related to reactor safety and compliance with the Commission=s rules and regulations, and with the conditions of your operating license. The inspection consisted of a selected examination of procedures and representative records, observations of activities, and interviews with personnel. Each inspection finding was assessed using the applicable Significance Determination Process (SDP). All findings either Ascreened out@ of the SDP or were determined to be within the licensee response band (i.e. Green).

In accordance with 10 CFR 2.790 of the NRC=s ARules of Practice,@ a copy of this letter and its enclosures will be placed in the NRC Public Document Room.

Sincerely,

/RA/

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

Enclosure: Inspection Report 05000272/1999011, 05000311/1999011

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U.S. NUCLEAR REGULATORY COMMISSION

REGION I

Docket Nos:	05000272, 05000311
License Nos:	DPR-70, DPR-75
Report No:	05000272/1999011, 05000311/1999011
Licensee:	PSEG Nuclear LLC
Facility:	Salem Nuclear Generating Station, Units 1 & 2
Location:	P.O. Box 236 Hancocks Bridge, NJ 08038
Dates:	November 29, 1999 - January 9, 2000
Inspectors:	Scott A. Morris, Senior Resident Inspector F. Jeff Laughlin, Resident Inspector
Approved By:	Glenn W. Meyer, Chief, Projects Branch 3 Division of Reactor Projects

SUMMARY OF FINDINGS

Salem Generating Station, Units 1 & 2
NRC Inspection Report 05000272/1999011, 05000311/1999011

The report covers a six-week period of resident inspection using the guidance contained in NRC Inspection Manual Chapter 2515*. The significance of issues is indicated by their color (green, white, yellow, red) and was determined by the Significance Determination Process in draft Inspection Manual Chapter 0609.

Performance Indicator Verification

! PSEG did not accurately report data needed to support the *Containment Leakage* performance indicator (PI). Specifically, PSEG reported a leak rate value that did not reflect the Asummation of the highest (as found) minimum path leakage values@ measured during the refueling outage as required by the PI reporting manual. This error did not affect the outcome of the PI with respect to its threshold, and the PI remained Green. (Section 4OA2.2).

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Report Details

SUMMARY OF PLANT STATUS

Unit 1 began the period at 100% and remained there until December 31, 1999 when operators reduced power to 90% as a Amillennium rollover@ precautionary measure. Full power operation was restored on January 1, 2000. Operators performed an unplanned power reduction to 91% on January 4 following the loss of the intermediate portion of the A feedwater heater string. Power was again returned to 100% on January 6, but later that day the intermediate portions of all three heater strings were inadvertently lost causing the operators to manually trip the unit due to the loss of feedwater. Unit 1 remained offline for the balance of the inspection period.

Unit 2 began the period at 100%, but was reduced to 96% on December 6, 1999, following the initiation of a steam leak on the 26B high pressure feedwater heater. Operators returned the unit to 100% on December 8. On December 31, 1999, operators reduced power to 90% as a Amillennium rollover@ precautionary measure. Full power operation was restored on January 1, 2000, and remained there for the remainder of the inspection period.

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, and Barrier Integrity

1R01 Adverse Weather

a. Inspection Scope

The inspectors reviewed procedure SC.OP-PT.ZZ-0002(Z), *Station Preparations for Winter Conditions*, completed on December 31, 1999, to assess PSEG=s preparation for cold weather conditions, and to verify that PSEG had taken appropriate actions to limit the risk of initiating events and adequately protect mitigating systems due to freezing conditions.

b. Observations and Findings

There were no findings identified. The inspectors noted that although the procedure stated that it should Anormally@ be performed in October and January of each year, operators did not complete the winterization preparations until December 31, 1999.

1R03 Emergent Work

a. Inspection Scope

The inspectors reviewed the circumstances associated with an emergent need on December 20, 1999, to remove the 21 high head safety injection pump from service to clean the pump gear oil cooler (degraded due to service water biofouling). Management controls to minimize plant risk were evaluated during the time this pump was out of service for corrective maintenance, as was pump gear oil cooler performance trend information.

b. Observations and Findings

There were no findings identified, however, the inspectors made several observations associated with this issue. PSEG collects performance information for the safety injection pump gear oil coolers on a monthly basis to provide early detection of service water biofouling. The inspectors noted that this particular gear oil cooler failed its biofouling performance test on November 22, 1999. The system engineer recognized this failure and promptly initiated a priority 1 work request to remove the pump from service to allow maintenance technicians to clean the cooler. However, due to errors in coordination and communication between the engineering, operations, and work management organizations, this work was not placed into the on-line work schedule for cleaning prior to the next scheduled monthly performance test. On December 19, 1999, operators performed the monthly test again with unsatisfactory results. Following this test, PSEG management recognized the need to promptly clean this cooler and removed the pump from service on an emergent basis the next day. The inspectors verified that the combination of equipment already out of service at the time the 21 high head safety injection pump was removed did not result in a risk-significant safety system alignment, though it did perturb the pre-planned schedule of maintenance activities.

1R04 Equipment Alignment

a. Inspection Scope

The inspectors conducted a partial walkdown of the 2B and 2C emergency diesel generators (EDGs) during a planned 2A EDG outage to verify the continued operability of the redundant trains. The inspectors conducted similar walkdowns of redundant trains during planned outages of containment fan coil units, safety-related chiller units, service water pumps and high head safety injection pumps.

b. Observations and Findings

There were no findings identified.

1R05 Fire Protection

a. Inspection Scope

The inspectors routinely toured high fire risk areas in the plant, including the relay and switchgear rooms and steam generator feed pump areas to assess PSEG=s control of transient combustible material and ignition sources, fire detection and suppression capabilities, fire barriers, and any related compensatory measures.

b. Observations and Findings

There were no findings identified.

1R10 Large Containment Valves

a. Inspection Scope

On January 4, 2000, the inspectors observed the testing and reviewed the results of periodic local leak rate testing of the 2VC1, 2, 3 and 4 containment purge system valves. These valves provide containment integrity for the largest building penetrations besides the personnel air locks and the equipment hatch. Previous leak rate associated with these penetrations was also examined for trend analysis data.

b. Observations and Findings

There were no findings identified.

1R13 Maintenance Work Prioritization

.1 11 and 21 Service Water Header Outages

a. Inspection Scope

PSEG recently began a program of inspecting environmentally qualified motor operated valves (MOVs) during on-line maintenance instead of during plant outages. Many of these MOVs are in the safety-related service water (SW) system. The inspectors reviewed evolution plans and observed maintenance associated with the 11 and 21 SW header outages to perform these MOV inspections. The inspectors verified the effectiveness of PSEG's work prioritization, control and risk assessment for this maintenance.

b. Observations and Findings

There were no findings identified. The inspectors observed that PSEG exhibited ineffective coordination and communication between planning, inservice testing and operations personnel, particularly since this was the first time that this MOV maintenance was performed during power operations.

.2 Steam Leak on 2PT505 Root Valve

a. Inspection Scope

The inspectors reviewed the plan, attended the pre-evolution briefing, and observed operator actions for the repair of a steam leak on the 2PT505 root valve to assess PSEG's prioritization and control of this evolution, as well as the level of maintenance support. 2PT505 is a pressure transmitter that provides one of two indications of main turbine impulse pressure for inputs into several risk-significant plant control systems.

b. Observations and Findings

There were no findings identified.

1R14 Nonroutine Plant Evolutions

.1 Unit 1 Feedwater Heater Train Failure

a. Inspection Scope

On January 4, 2000, Salem Unit 1 experienced an unplanned loss of the A train of the intermediate feedwater heater string due to a closure of the air-operated inlet isolation valve (11CN27). Control room operators promptly reduced plant power to 91% in accordance with abnormal operating procedures to mitigate the effects of the reduction in steam generator feed pump (SGFP) suction pressure and feedwater heating. The inspectors examined numerous plant records and indications associated with the event, and interviewed the operators that were in the control room at the time of the occurrence. Additionally, the inspectors evaluated PSEG=s troubleshooting efforts in their attempt to understand and correct the cause of the valve failure.

b. Observations and Findings

There were no findings identified.

On January 6, 2000, approximately 36 hours after the event, the 11CN27 valve was reopened and reactor power was increased to 100% as PSEG was not able to determine the cause of the inadvertent closure of the feedwater heater string inlet isolation valve. However, technicians instrumented the suspect components with the approval of the Station Operations Review Committee with the intent of capturing more definitive failure information should the problem recur. (See also section1R14.2 below)

.2 Unit 1 Reactor Trip

a. Inspection Scope

The inspectors provided prompt on site response to an unplanned manual reactor trip of Salem Unit 1 on January 6, 2000. Operators manually tripped the unit following the loss of the 11 SGFP and the expected subsequent loss of the 12 SGFP. Both SGFPs ultimately tripped automatically as a direct result of the unexpected closure of inlet isolation valves on all three intermediate feedwater heater strings (11CN27, 12CN27, 13CN27), effectively eliminating the SGFP suction flow path. PSEG suspected the cause of this event to be related to the earlier January 4 event described in Section 1R14.1 above. The scope of the inspector=s review and assessment in this report was limited to the initial operator actions following the reactor trip and a review of related equipment performance anomalies due to the inspection period=s end. (A detailed evaluation of PSEG=s root cause and corrective actions stemming from the trip, as well as the risk management approach used during the resulting forced outage, is planned for the next resident inspection report.)

b. Observations and Findings

There were no findings identified.

The inspectors noted that control room operators acted conservatively in manually tripping the reactor upon discovery of the feedwater heater valve closures, and properly implemented the emergency operating procedures following the trip. The shift supervisor made a timely and accurate 10 CFR 50.72 non-emergency event notification in accordance with the Salem emergency classification guide. Equipment performance abnormalities associated with a source range nuclear instrumentation channel, the main condenser offgas radiation monitor, and the 12 auxiliary feedwater pump discharge valves were promptly recognized and compensated for in accordance with station procedures.

.3 Unit 2 Unusual Event

a. Inspection Scope

The inspectors provided prompt on site response to an Unusual Event declaration at Unit 2 on December 11, 1999. At approximately 1:50 a.m., the 10-ton carbon dioxide (CARDOX) system tank in the auxiliary building developed a leak on level transmitter tubing which caused the atmosphere in the room containing the tank to reach unacceptably low oxygen concentration. (The CARDOX unit is a standby system used for fire suppression in various safety related areas throughout the auxiliary building.) During post-event troubleshooting, PSEG concluded that a small diameter copper tube connected to the tank experienced a vibration-induced through-wall crack. The tubing was mounted in such a way as to be subjected to frequent vibration due to the operation of a nearby gas compressor. PSEG technicians promptly repaired the condition and terminated the Unusual Event at 5:41 a.m. on December 11.

The inspectors evaluated the station's performance with regard to emergency classification guide usage, procedure adherence, and event mitigation. Subsequent root cause and corrective actions were also examined.

b. Observations and Findings

There were no findings identified.

.4 Unit 1 Main Turbine Lubricating Oil Cooler Swap

a. Inspection Scope

The inspectors witnessed plant operators perform a risk-significant evolution involving the on-line transfer of main turbine lubricating oil (MTLO) cooling from the 12 to the 11 MTLO cooler. These coolers use station SW as a cooling medium, and as such are subject to degradation from biofouling. February 1999 was the last time operators had swapped MTLO coolers with the unit at power; on that occasion operators improperly operated the cooler transfer valve which resulted in a main turbine and reactor trip. In contrast to the February 1999 evolution, operators conducted extensive pre-job briefings and just-in-time training, and provided extensive management oversight for the task. Operators successfully transferred coolers without incident.

b. Observations and Findings

There were no findings identified.

1R15 Operability Evaluations

a. Inspection Scope

The inspectors reviewed operability determination 99-014 for the 12 containment fan cooler unit (CFCU) to verify that equipment operability was justified and that the CFCU could perform its design function. This CFCU had demonstrated degraded thermal performance during testing to support the requirements of Generic Letter 89-13, *Service Water System Problems Affecting Safety-Related Equipment.*

b. Observations and Findings

There were no findings identified.

1R16 Operator Work-Arounds

a. Inspection Scope

The inspectors reviewed all outstanding Unit 1 and 2 operator workarounds (OWAs) to identify any potential negative effect on the function of mitigating systems. The inspectors also discussed PSEG=s process for handling OWAs with the senior reactor operator (SRO) in charge of tracking these issues.

b. Observations and Findings

There were no findings identified.

The inspectors determined that there was no formal process to capture potential OWAs which could arise as compensatory actions for operability determinations. This issue was also documented in NRC Inspection Report 05000272&311/1999005. The SRO stated that although there was no corrective action notification written to document this shortcoming, PSEG was formulating corrective actions to correct it.

1R19 Post-Maintenance Testing

a. Inspection Scope

The inspectors reviewed post-maintenance test (PMT) procedures and PMT data for the December 12-19, 1999, 11 safety-related chiller outage to verify that test activities confirmed the capability of the chiller to perform its design function at the completion of planned maintenance.

b. Observations and Findings

There were no findings identified. However, the inspectors observed that maintenance personnel did not have adequate parts staged for the expanded scope on the condenser recirculation pump, which resulted in an additional three days of unavailability time.

1R22 Surveillance Testing

a. Inspection Scope

The inspectors either observed or reviewed the results of several scheduled equipment surveillance tests, a sampling of which include the:

- 13 auxiliary feedwater pump,
- 23 auxiliary feedwater pump,
- 22 residual heat removal (RHR) pump

The inspectors compared actual test data with established acceptance criteria to ensure that the various systems and components met licensing basis requirements.

b. Observations and Findings

There were no findings identified, however the inspectors made one observation related to the data collected during the 22 RHR pump test on December 22, 1999. Specifically, during the pump flow measurement, the inspectors noted that the operators recorded digital volt meter (DVM) readings in increments of 0.01 volts despite the DVM's accuracy beyond that. The governing test procedure, ST.OP-ST.RHR-0002, did not specify the accuracy to which data should be recorded. However, the inspectors noted that based on the calculation used to convert the voltage reading to RHR pump flow, a difference of only 0.005 volts in the recorded DVM reading could result in the acceptance criteria not being satisfied. As an example, a recorded value of 1.552 volts could result in an unacceptable test, but be masked if technicians rounded the value up and recorded 1.60 volts. The inspectors raised this issue with the plant operators who subsequently initiated a corrective action request to clarify the procedural guidance.

1R23 Temporary Plant Modifications

a. Inspection Scope

During the report period PSEG personnel twice attempted to repair a steam leak on the 11 SGFP steam supply check valve (11MS43) using temporary leak sealing methods. The inspectors performed detailed reviews of the engineering analyses, calculations and safety evaluations that were performed to support the two repair attempts. The inspectors also observed the actual leak sealing evolutions as they were performed to determine whether the work was performed in accordance with established guidance and also within the parameters assumed in the noted engineering documents. (Neither of the two attempts were completely successful at mitigating the leak. The valve was successfully replaced during the unit forced outage which began January 6, 2000.)

b. Observations and Findings

There were no findings identified.

3. SAFEGUARDS

Physical Protection [PP]

PP3 Response to Contingency Events

a. Inspection Scope

The inspectors reviewed and assessed PSEG=s preparations for a potential labor strike by the contracted security guard force personnel. The inspectors maintained frequent contact with security department management and evaluated PSEG=s strike contingency plans as described in the site physical security plan. The labor union and security management ultimately reached a contract agreement without the need for a strike.

b. Observations and Findings

There were no findings identified.

4. OTHER ACTIVITIES

4OA2 Performance Indicator Verification

.1 Mitigating Systems Cornerstone

a. Inspection Scope

The inspectors reviewed the December 1999 data for the *Safety System Unavailability* for *emergency AC power* and *auxiliary feedwater* (AFW) PIs for both Salem units, to verify the accuracy and completeness of the data. The inspectors used the NEI PI reporting manual as a standard. They also interviewed PSEG personnel responsible for compiling and reporting this information.

b. Observations and Findings

There were no findings identified.

.2 Barrier Integrity Cornerstone

a. Inspection Scope

The inspectors verified the accuracy and completeness of the data for the *Containment Leakage* PI. Leak rate data collected for each Salem unit in 1999 was reviewed to determine whether all of the information meeting the PI definition in NEI 99-02 draft revision D, ARegulatory Assessment Performance Indicator Guideline,@ was included in the data set.

b. Observations and Findings

(1) *Containment Leakage*

The inspectors identified that PSEG had properly collected all of the necessary containment leak rate information but had failed to accurately calculate the PI as required by the guidance document. Specifically, the NEI guidance states in part that Afor months when an outage is ended, the reported value should reflect a summation of the highest (as found) minimum path leakage values measured during the outage.@ The inspectors determined that PSEG committed two errors in calculating this PI value. First, minimum path leak rate values were not used exclusively, rather the reported value contained a mix of minimum and maximum path data. Though the guidance permits the use of maximum path values in lieu of minimum path data, the information was not used consistently. This inconsistent use of containment rate data resulted in a more conservative number being reported. Second, the reported PI value was not a summation of the individual as-found penetration leak rates. Instead, PSEG reported the highest daily Arunning@ leak rate recorded during the month that the outage ended.

Because the second error described was not significant in that no change in the NRC=s action would have resulted from this data and it was not willful, this error is considered a minor violation not subject to formal enforcement action. However, this issue will remain unresolved pending the inspectors= review of PSEG=s next data submittal in the first quarter of 2000. **(URI 05000272/1999011-01)**

4OA4 Other

.1 (Closed) URI 05000311/1999009-02: Inaccurate submittal of *Scrams with Loss of Normal Heat Removal* performance indicator (PI) data. The inspectors verified that PSEG corrected the error identified in NRC Inspection Report 05000272&311/1999009 in the December 1999 PI data submittal.

.2 Year 2000 Rollover: The senior resident inspector was present in the Salem main control room from 11:00 p.m. to 01:00 a.m. and remained on site until 05:00 a.m. He verified that the Salem plants remained unaffected by any potential year 2000 computer problems.

4OA5 Management Meetings

a. Exit Meeting Summary

On January 19, 2000, the inspectors presented their overall findings to members of PSEG Nuclear management led by Marios Kafantaris of the Salem operations department. PSEG management acknowledged the findings presented and did not contest any of the inspectors= conclusions. Additionally, they stated that none of the information reviewed by the inspectors was considered proprietary.

ITEMS OPENED AND CLOSED

Opened

05000272/1999011-01	URI	Inaccurate *Containment Leakage* performance indicator data submittal. (Section 4OA2.2)

Closed

05000311/1999009-02	URI	Inaccurate *Scrams with Loss of Normal Heat Removal* performance indicator data submittal. (Section 4OA4.1)

LIST OF ACRONYMS USED

AFW	Auxiliary Feedwater
CARDOX	Carbon Dioxide
CFCU	Containment Fan Cooler Unit
DVM	Digital Volt Meter
EDGs	Emergency Diesel Generators
LLRT	Local Leak Rate Test
MOVs	Motor Operated Valves
MTLO	Main Turbine Lubricating Oil
NRC	Nuclear Regulatory Commission
OWAs	Operator Workarounds
PDR	Public Document Room
PI	Performance Indicator
PMT	Post-Maintenance Test
PSEG	Public Service Enterprise Group - Nuclear LLC
RHR	Residual Heat Removal
SDP	Significance Determination Process
SGFP	Steam Generator Feed Pump
SORC	Station Operations Review Committee
SRO	Senior Reactor Operator
SW	Service Water

ATTACHMENT 1
NRC=s REVISED REACTOR OVERSIGHT PROCESS

The federal Nuclear Regulatory Commission (NRC) 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 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 indicate issues that, while they may not be desirable, represent very low safety significance. WHITE findings represent issues with low to moderate safety significance, which may require additional NRC inspections. YELLOW findings represent issues with substantial safety significance, which would require the NRC to take additional actions. RED findings represent issues with high safety significance and an unacceptable loss of safety margin, which would result in the NRC taking significant actions that could include ordering the plant shut down.

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 incremental degradation in safety: GREEN, WHITE, YELLOW, and RED. The color for an indicator corresponds to levels of performance that may result in increased NRC oversight (WHITE), performance that results in definitive, required action by the NRC (YELLOW), and performance that is unacceptable but still provides adequate protection to public health and safety (RED). GREEN indicators represent performance at a level requiring no additional NRC oversight beyond the baseline inspections.

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. As a licensee=s safety performance degrades, the NRC will take more and increasingly significant action, as described in the matrix. 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.

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