U. S. NUCLEAR REGULATORY COMMISSION

REGION I

Docket Nos:	50-272, 50-311
License Nos:	DPR-70, DPR-75
Report No.	50-272/98-03, 50-311/98-03
Licensee:	Public Service Electric and Gas Company
Facility:	Salem Nuclear Generating Station, Units 1 & 2
Location:	P.O. Box 236 Hancocks Bridge, New Jersey 08038
Dates:	March 16, 1998 - May 3, 1998
Inspectors:	S. A. Morris, Senior Resident Inspector, Salem S. M. Pindale, Senior Resident Inspector, Hope Creek F. J. Laughlin, Resident Inspector, Salem H. K. Nieh, Resident Inspector, Salem G. S. Barber, Project Engineer T. H. Fish, Operations Engineer N. T. McNamara, Emergency Preparedness Specialist E. B. King, Physical Security Inspector R. L. Fuhrmeister, Reactor Engineer K. Young, Reactor Engineer
Approved by:	James C. Linville, Chief, Projects Branch 3 Division of Reactor Projects

9806030294 980522
PDR ADOCK 05000272
Q PDR

EXECUTIVE SUMMARY

Salem Nuclear Generating Station
NRC Inspection Report 50-272/98-03, 50-311/98-03

This integrated inspection included aspects of licensee operations, engineering, maintenance, and plant support. The report covers a seven-week period of resident inspection; in addition, it includes the results of announced inspections of the emergency preparedness programs by regional inspectors.

Operations

Overall, Salem plant management and staff controlled the Unit 1 reactor startup and power ascension test activities well. The operating crews were attentive, used excellent communication skills, and responded appropriately to planned and emergent events and issues. Reactor engineering and chemistry department support, as well as pre-evolution briefings, were usually of good quality although some deficiencies were observed during low power physics testing. Strong management and quality assurance oversight was indicated by continuous on-site management presence during restart activities and the willingness to halt further plant evolutions following the identification of emergent issues. Good self-assessment capability was evident during hold point release discussions with the NRC Salem Assessment Panel. (Section O1.1)

Operators responded promptly and effectively to an unexpected loss of the 21 steam generator feed pump while a 100% power. All plant equipment functioned as designed during the transient. (Section O1.2)

The 125 volt DC electrical distribution system was properly aligned for existing plant conditions at Unit 1 and 2. Material condition and housekeeping were acceptable. Adequate surveillance test procedures were implemented to verify system operability. (Section O2.1)

PSE&G's actions to address and correct the cause of missing service water (SW) strainer filter disks and cracked filter disk retaining rings were appropriate and promptly implemented. Unit 2 control operators responded promptly to the clogging of two SW pump discharge strainers in the SW same loop. PSE&G management's decision to take Salem unit 2 off-line for strainer repairs was appropriate, and corrective actions were adequate. (Section O2.2)

Maintenance

PSE&G determined that the lack of clear ownership for and coordination of recent emergency diesel generator (EDG) on-line maintenance outages resulted in unnecessary delays in work completion, extending the overall equipment unavailability time. Inadequate tagging controls during the 2B EDG outage resulted in an electrical breaker blocking tag being released while personnel were actively working on equipment supplied by that breaker. (Section M1.2)

PSE&G implemented appropriate corrective actions to repair degraded auxiliary feedwater piping revealed by a through-wall leak on a pump minimum-flow orifice line. Technical specification and ASME code class 3 requirements were satisfied. However, this event revealed a weakness in scope of the flow-accelerated corrosion program in that only the steam-driven pumps were included for monitoring. (Section M2.1)

Engineering

PSE&G restored the 22 steam generator steam flow channels II and III to an operable status in a slow and deliberate manner, meeting all technical specification requirements during the process. (Section E1.1)

Plant Support

Based upon a review of selected items and procedures, the inspectors concluded that PSE&G's method for tracking Emergency Preparedness corrective actions was very good and that the self-assessment program provided good feedback to the staff. The timeliness of resolving some identified issues was weak. (Section P1)

The emergency response facilities and equipment were in a good state of operational readiness. Surveillance tests and inventories were performed as required and discrepancies were resolved in a timely manner. Expenditure of resources to improve equipment and facilities demonstrated PSE&G's commitment to support and maintain the emergency preparedness program. Overall, the inspectors considered this area to be very good. (Section P2)

PSE&G emergency plan changes were adequately reviewed in accordance with 10 CFR 50.54(q). PSE&G planned to review, evaluate/rewrite the emergency plan implementing procedures for conformance to other station procedures and to improve the review process. The inspectors also concluded that letters of agreement with offsite agencies were in place. (Section P3)

PSE&G conducted emergency response training and drills as required. Based upon overall good performance during the drills and the March 1998 biennial full-participation emergency exercise, the inspectors concluded that training for the ERO was effective. (Section P5)

The department reorganization and hiring of a manager with extensive EP experience enhanced the EP program. The inspectors concluded that the positive findings during this inspection were an indication that the program had significantly improved since the last inspection. (Section P6)

Quality Assurance audits of the emergency preparedness (EP) program were thorough and the reports were useful to PSE&G management in assessing the effectiveness of the EP program and providing enhancement recommendations. This area was assessed as excellent. (Section P7)

TABLE OF CONTENTS

Report Details

Summary of Plant Status

Unit 1 began the period in Mode 4, and transitioned to Mode 3 on March 17, 1998. Reactor startup began and criticality was achieved on April 7, 1998. The unit reached Mode 1 on April 12, 1998 and 100% power on May 3, 1998.

Unit 2 began the period at approximately 50% power during a power ascension following a unit forced outage. 100% power was achieved on March 17, 1998. Power was reduced to 60% on March 24, 1998 in response to an unplanned loss of the 21 steam generator feed pump, and later restored to full power the next day. On April 18, 1998, operators reduced power and removed the unit from the offsite electrical network following the unplanned inoperability of a service water cooling loop. Following resolution of the service water issues, the unit was synchronized to the offsite network on April 11, 1998. 100% power was reached on April 13, 1998, and remained at that level for the balance of the inspection period.

I. Operations

O1 Conduct of Operations

O1.1 Unit 1 Reactor Startup and Power Ascension

a. Inspection Scope (71707, 71715)

On April 1, 1998, based on the recommendation of the Salem Assessment Panel (SAP), the NRC modified Confirmatory Action Letter (CAL) 1-95-009 to permit PSE&G to restart Salem Unit 1. NRC resident and regional inspectors conducted augmented inspection coverage of the Unit 1 reactor startup and low power physics testing from April 7 - 11, 1998. Additionally, the resident inspectors closely monitored subsequent power ascension activities through the end of the report period, including the "hold point" testing and assessments at 25%, 50%, and 90% power, as dictated by the CAL.

b. Observations and Findings

Salem operators entered Mode 2 and achieved criticality at Unit 1 on April 7, 1998, and then raised power to 10^{-8} amperes in the intermediate range in order to conduct low power physics testing. During this period, the inspectors observed that the control room operators exhibited good use of procedures and, clear communications. Additionally, good managerial and quality assurance department oversight was noted, and control room distractions were kept to a minimum. Pre-evolution briefings frequently incorporated lessons learned from the Unit 2 startup in August 1997.

Several problems were noted during the reactor physics testing, largely stemming from weak operations support from other departments. For example, the inspectors witnessed a "control rod swap" reactivity measurement pre-evolution briefing conducted by reactor engineers which lacked clarity and caused confusion among reactor operators. The control room supervisor frequently stopped the briefing to ensure that all questions and concerns were properly addressed. Additionally, an equipment deficiency associated with an out-of-calibration pure water flow integrator caused operators to over-dilute the reactor coolant system during the test, which necessitated a subsequent unplanned boration to compensate for the error. However, the boric acid volume recommended by the reactor engineer on shift was incorrect because it was based on a faulty interpretation of control rod worth tables. Because of a conservative operational practice to borate and dilute in increments that were half the recommended volumes, the effect of this boration error was minimized.

The inspectors also observed a weakness in operations support during the execution of a boron endpoint determination test. This test, conducted in accordance with procedure S1.RE-RA.ZZ-0005 (Q), required three separate attempts in order to be successfully completed. Specifically, operators experienced difficulty preventing power from exceeding 95% of the indicating scale on the reactivity computer during the test. This issue was due primarily to coordination problems between the operator performing the required reactivity manipulations and the reactor engineer directing the evolution.

A final example involved a chemistry department recommended lithium hydroxide addition to the reactor coolant system to adjust plant pH levels. While Unit 1 was still at 10^{-8} amperes for physics testing, operators approved the chemical addition. In order to understand the impact this addition would have on reactivity, chemistry technicians informed the operators that approximately 10 gallons of pure water would be added to the plant. After the addition was completed, operators promptly identified that reactor power was increasing at a rate greater than expected, and added boric acid to reduce power back to the desired level. Based on volume control tank level changes, operators computed that nearly 90 gallons of pure water had been injected during the chemical addition. The discrepancy between the expected and actual water volumes, which caused a greater than anticipated reactivity excursion, was later attributed to insufficient system operating knowledge by the involved chemistry technicians.

Because of the self-revealing nature of the above issues, PSE&G operations management and quality assurance inspectors were promptly aware of the concerns, and responded appropriately to each. Corrective action requests were initiated both to document each of the discrete issues and to integrate all of the concerns associated specifically with reactivity management into a single comprehensive review. As each issue was identified, plant supervision placed a hold on further Unit 1 evolutions until the causes were understood and interim corrective measures were implemented. Additionally, these and other issues were discussed at length at the PSE&G management review committee meeting conducted at the 25% power hold point.

Following completion of the reactor physics testing, operators slowly and deliberately raised reactor power to 25% in accordance with procedure TS1.SE-SU.ZZ-0001(Q), *Startup and Power Ascension Sequence*, and S1.OP-IO.ZZ-0003(Q), *Hot Standby to Minimum Load.* Unit 1 achieved Mode 1 on April 12, 1998, and was later synchronized to the offsite electrical network on April 17, 1998. Several emergent secondary plant issues were promptly and effectively addressed during this period, including minor steam and water leaks, a small fire, and an inadvertent CARDOX initiation in the main generator exciter housing. The inspectors observed main turbine overspeed trip testing, generator loading, and reactor core flux mapping during this period. All of these evolutions were thoroughly briefed, properly supervised, and implemented with successful results.

On April 18, 1998, members of the SAP held a conference call with PSE&G management to review the station's request for release from the 25% power hold point. During the call, the SAP discussed PSE&G's internal assessments of Unit 1 startup issues and test results, including all of the issues described above. During the post-call caucus, the SAP concluded that PSE&G's assessment was sufficiently self-critical and that adequate plans were either completed or in place to implement needed corrective actions. As a result, the SAP recommended and the Regional Administrator subsequently approved a release from the 25% hold point.

On April 23, 1998, with Unit 1 at 47% power, operators successfully completed a planned 10% load swing test. This test verified that the newly installed digital feedwater control system was capable of properly responding to small load changes. No problems were noted during this test. On April 24, 1998, the SAP held another conference call with PSE&G management to discuss release from the 50% power hold point. With the exception of a status update of recent service water system biofouling concerns (see Section O2.2 of this report), no significant equipment or human performance issues were raised during the conference call. As such, later that day, the Regional Administrator approved a release from the 50% hold point.

On April 30, 1998, the inspectors witnessed the conduct of a 25% load rejection test from an initial 88% power level, again conducted to verify the performance of the digital feedwater control system. Operators prepared for this evolutions by conducting dynamic training in the Unit simulator. While the feedwater controls responded appropriately to the planned transient, operators observed apparently abnormal control rod speed fluctuations with the rod control system in "automatic." Upon recognition of this issue, operators promptly placed the control rods in "manual" until the cause of the unexpected response could be understood and corrected. During the following week, the inspectors observed maintenance technicians and engineering personnel implement a well controlled and comprehensive rod control system troubleshooting plan and transient response evaluation.

On May 1, 1998, the NRC SAP members held another conference call with PSE&G management, this time to discuss a requested release from the 90% power hold point. Discussions during this call primarily centered on the apparent rod control system anomalies experienced during the 25% load rejection testing. Based on PSE&G management's planned actions to promptly evaluate and correct this apparent rod control problem, and to discuss the final assessment of this issue with the SAP prior to commencing a planned 40% load reduction and feed pump trip test, the NRC released Unit 1 from the 90% power hold point and permitted PSE&G to raise power to 100%. On May 3, 1998, Salem operators achieved 100% power at Unit 1.

At the conclusion of the report period, only the 40% load reduction and feedwater pump trip test from 90% power remained outstanding in the Unit 1 restart and power ascension test plan. The modified NRC CAL 1-95-009 remained in effect until PSE&G successfully completed these tests and performed a comprehensive assessment of the startup test plan and any "lessons learned." The inspectors independently concluded that overall, PSE&G's implementation of the Unit 1 restart plan was an improvement over the Unit 2 restart (see NRC Inspection Report 50-311/97-15), as indicated by fewer emergent equipment deficiencies and test coordination errors.

c. <u>Conclusions</u>

Overall, Salem plant management and staff controlled the Unit 1 reactor startup and power ascension test activities well. The operating crews were attentive, used excellent communication skills, and responded appropriately to planned and emergent events and issues. Reactor engineering and chemistry department support, as well as pre-evolution briefings, were usually of good quality although some deficiencies were observed during low power physics testing. Strong management and quality assurance oversight was indicated by continuous on-site presence during restart activities and a willingness to halt further plant evolutions following the identification of emergent issues. Good self-assessment capability was evident during hold point release discussions with the NRC Salem Assessment Panel.

O1.2 <u>Unplanned Unit 2 Load Reduction</u>

a. <u>Inspection Scope (93702)</u>

The inspectors reviewed Salem Unit 2 operators response to a March 24, 1998 event involving an electrical power transient affecting steam generator feed pump (SGFP) controls.

b. <u>Observations and Findings</u>

An unexpected electrical power spike resulted in the momentary partial loss of non-vital 115 volt AC power. This event in turn caused a shutdown of the 21 SGFP, which lost governor control power. Operators acknowledged the associated overhead alarm, observed that the 21 SGFP speed was lowering, and initiated a manual main turbine generator load reduction to 60% power. Based on operator interviews and a review of narrative logs, the inspectors determined that plant operators correctly followed alarm response and abnormal operating procedures to stabilize the plant. The inspectors found the impact of this event on plant safety minimal, in that all plant systems responded as designed to the transient and no safety systems were challenged as a result. Operators returned Unit 2 to full power on March 25, 1998 after testing all affected equipment to verify continued proper operation. At the conclusion of the report period, PSE&G had not determined the root cause for this electrical transient event, but also concluded that all plant equipment functioned as designed in response to the transient.

c. Conclusions

Operators responded promptly and effectively to an unexpected transient associated with the 21 steam generator feed pump while a 100% power. All plant equipment functioned as designed during the transient.

O2 Operational Status of Facilities and Equipment

O2.1 125 Volt DC (VDC) Distribution System Walkdown

a. Inspection Scope (71707)

The inspectors conducted a comprehensive walkdown of the accessible portions of the 125 VDC electrical distribution system. The inspectors reviewed the Updated Final Safety Analysis Report (UFSAR), Technical Specifications (TS), Configuration Baseline Documentation, and TS surveillance procedures for background information.

b. Observations and Findings

Material condition and housekeeping of 125 VDC batteries and associated busses were acceptable at both Salem units. System configuration was consistent with UFSAR system descriptions, and was properly aligned for existing plant conditions. The inspectors reviewed procedures S1(S2).OP-ST.125-0001,"Electrical Power Systems 125 VDC Distribution," and determined that the procedure adequately verified system operability requirements specified in plant TS at the appropriate frequency. Some minor discrepancies were noted and brought to the attention of system engineering. For example, two cells on the 2B 125 VDC battery had plates which were slightly bowed. Actions taken to address these items were timely and appropriate.

c. Conclusions

The 125 volt DC electrical distribution system was properly aligned for existing plant conditions at Unit 1 and 2. Material condition and housekeeping were acceptable. Adequate surveillance test procedures were implemented to verify system operability.

O2.2 Update on Service Water Biofouling

a. Inspection Scope (40500, 92901, 92902, 92903)

The inspectors reviewed PSE&G's response and actions taken to address degraded service water system (SW) strainers. Related SW biofouling issues were previously discussed in NRC Inspection Report 50-272 & 311/98-01.

b. Observations and Findings

On April 3, 1998, maintenance technicians identified one missing filter disk and five cracked filter disk retaining rings during an internal inspection of 23 SW pump discharge strainer (Unit 2). A similar inspection of 14 SW strainer (Unit 1) also revealed one missing disk and approximately forty cracked retaining rings. No adverse temperature trends were identified in any SW cooled heat exchangers. PSE&G engineers attributed the cause of the cracked rings to excessive torque during installation. The plastic retaining rings were installed using an air impact wrench, with no specific torque requirement. Strainer manufacturer, S. P. Kinney Engineers, Inc., indicated that factory installation of the rings is "hand tight plus an additional one half of one turn." Maintenance procedure SC.MD-PM.SW-0003, "Service Water Auto Strainer Adjustment, Inspection, Repair, and Replacement," did not specify a particular method of ring installation. Air wrenches were used to expedite the task, since hand installation requires several days to complete. PSE&G management decided to overhaul each Unit 1 and 2 SW strainer (12 total) and install each new retaining ring by hand. The inspectors verified that the noted maintenance procedure was modified to specify hand installation of the retaining rings.

On April 8, 1998, with Salem Unit 2 at 100%, operators declared one of the two service water (SW) loops inoperable due to both the 24 and 25 SW pump strainer motors tripping on overload. This rendered the associated pumps inoperable. Technical Specification 3.7.4 requires two operable SW loops, and the action statement allows 72 hours to restore the inoperable SW loop to an operable status before a unit shutdown is required. At the time of event, one of the three strainers in the opposite SW loop was also unavailable due to pre-planned corrective maintenance. An NRC inspector was in the control room at the time of this event and observed that plant operators acted appropriately in response to the observed conditions. At the time of the event, Salem Unit 1 was in Mode 2 with low power physics testing in progress; no effects on the Unit 1 SW system were observed.

Within three hours of this event, PSE&G management elected to reduce power and take Unit 2 off-line for further investigation and repairs of the strainers, well before the expiration of the 72-hour TS allowed outage time. Subsequent inspections of the affected strainers revealed that they were clogged with excessive amounts of grass and debris. Though the root cause evaluation for this event was not yet completed by the end of the report period, several corrective actions were implemented, including: overhauling the SW strainers, replacing the strainer motor overload heaters, and adjusting all of the traveling screen spraywash nozzles. By the end of the report period, all of the Unit 1 and Unit 2 SW strainers had been overhauled, and most overload heaters were replaced with higher capacity overloads. The remaining overload heaters have been scheduled for replacement. The inspectors reviewed the overload sizing calculations, and no problems were noted. The inspectors also determined that the overload modification would not negatively impact electrical loading during accident conditions.

c. Conclusions

PSE&G's actions to address and correct the cause of missing service water (SW) strainer filter disks and cracked filter disk retaining rings were appropriate and promptly implemented. Unit 2 control operators responded promptly to the clogging of two SW pump discharge strainers in the SW same loop. PSE&G management's decision to take Salem unit 2 off-line for strainer repairs was appropriate, and corrective actions were adequate.

O8 Miscellaneous Operations Issues

O8.1 (Closed) Inspector Followup Item 50-311/97-03-02: Management Commitment Process

a. Inspection Scope (92702)

The inspectors reviewed and assessed a recent revision to the commitment management program procedure as a follow up to a similar review performed while evaluating Salem Unit 1 and Unit 2 for restart readiness.

b. Observations and Findings

As part of the restart action plan, Salem staff evaluated the commitment management process and subsequently instituted corrective actions to correct program deficiencies. One of these tasks, a revision of the commitment management program procedure, was not completed at the time NRC staff was inspecting the commitment process for restart readiness, and was therefore left open pending a review and assessment of the final procedure. PSE&G issued the revised commitment management procedure, NC.NA-AP.ZZ-0030(Q) in May 1997. The inspectors reviewed the document and determined that the procedure and program modifications were acceptable. This item is closed.

c. Conclusions

PSE&G appropriately revised the process by which license commitments are tracked and managed.

O8.2 (Closed) Violation 50-311/97-07-01: Failure to establish containment integrity within eight hours

a. Inspection Scope (92702)

The inspectors performed an on-site review and verification of PSE&G's corrective actions for the subject Notice of Violation.

b. Observations and Findings

In the violation response letter dated June 13, 1997, PSE&G management attributed the event cause to inadequate tracking of inoperable equipment. In response, PSE&G provided electrical systems technical specifications refresher training to licensed operators, and enhanced the technical specifications action statement tracking log. The inspector reviewed the refresher training and the revised tracking log and determined these corrective actions were reasonable and complete. This item is closed.

c. Conclusions

The PSE&G staff developed and implemented timely and reasonable corrective actions for a Notice of Violation involving a failure to promptly establish containment integrity.

O8.3 (Closed) LER 50-272/98-002-00,98-002-01: Auxiliary building ventilation excess flow damper found wired open with spring removed

a. Inspection Scope (90712, 92700)

The inspectors performed an on site review of LER 50-272/98-002-00. LER 50-272/98-002 Supplement 1, which documented the results of an evaluation performed to determine the safety significance of this issue. The inspectors reviewed and discussed the noted evaluation with PSE&G design engineers.

b. Observations and Findings

The circumstances surrounding the initial discovery and corrective actions related to this issue were previously discussed in NRC Inspection Report 50-272 & 311/97-21. No new issues were identified in this LER and all stated corrective actions have been completed. As such, this LER is closed.

Based in part on a discussion with PSE&G design engineers, the safety significance evaluation completed for this event was deemed to be reasonable. Specifically, this event had limited safety significance since the control room and offsite dose consequences were bounded by the loss of coolant accident and steam line break analyses. This LER supplement is closed.

c. Conclusions

Corrective actions for LER 50-272/98-002-00were reasonable and complete. The safety significance evaluation performed for this event, documented in LER Supplement 1, was also acceptable.

II. Maintenance

M1 Conduct of Maintenance

M1.1 General Comments

The inspectors observed all or portions of the following work activities and technical specification surveillance tests:

- W/O 980311218: 15 Service water strainer - inspect and check clearness
- W/O 980315118: Ultra-sonic test of 12 AFW minimum-flow orifice area
- W/O 980315129: Ultra-sonic test of 22 AFW minimum-flow orifice area
- W/O 971005022: 22 Charging pump lube oil heat exchanger - open, clean and inspect
- W/O 990131032: 22 Charging pump gear box heat exchanger - open, clean and inspect
- W/O 971228015: 22 Charging pump, clean and repack couplings
- W/O 980331158: 16 Service water strainer inspection/retaining ring replacement
- W/O 910529001: 12 Containment hydrogen analyzer - replace hydrogen sensor
- W/O 980408061: 25 Service water pump strainer backwash valve - inspect
- W/O 980408059: 24 Service water pump strainer - open and inspect
- W/O 971216022: 2B EDG lube oil heater - remove, clean, and inspect
- W/O 970605093: 2B EDG switch replacement
- W/O 980312302: 14 SW strainer grass and clearance inspection
- W/O 980320186: 13 SW strainer grass and clearance inspection
- W/O 980516040: Radiography test of 11SW53 (13 CFCU inlet check valve)
- W/O 980328091: Repair 25 SW strainer (seized)
- W/O 980312297: 23 SW strainer grass and clearance inspection
- W/O 980412104: 2A EDG fuel oil leak repair on 9R fuel pump
- W/O 960513198: 2C EDG oil leak repair on 6L cylinder
- S1.RE-RA.ZZ-0005: Boron endpoint determination
- S1.IC-FT.NIS-0014: 1N36 functional test
- S1.IC-CC.RCP-0018:1PT546(pressurizer pressure channel 2) calibration
- S1.IC-CC.RCP-0023:1PT474(pressurizer pressure channel 4) calibration
- S2.MD-FT.4KV-0002:2Bvital bus undervoltage testing
- S2.OP-SO.DG-0002: 2B EDG 15-minute post-maintenance run

The inspectors observed that the plant staff performed the maintenance activities effectively and in accordance with the standards defined by the station maintenance program. Salem plant staff also completed the noted surveillance tests safely, and effectively proved the operability of the associated systems. Minor deficiencies noted by the inspectors were referred to and promptly corrected by the PSE&G staff.

M1.2 Emergency Diesel Generator On-line Maintenance

a. Inspection Scope (71707,62707,92901,92902)

The inspectors reviewed the limiting condition for operation (LCO) maintenance plan for the April 14, 1998 2B emergency diesel generator (EDG) planned maintenance outage, observed implementation of associated work activities, and interviewed PSE&G management concerning the plan. The inspectors also reviewed documentation for the March 13, 1998 1B EDG outage, and the April 21, 1998 2C EDG planned maintenance outage.

b. Observations and Findings

1B EDG Outage:

At 4:41 a.m. on March 18, 1998, the 1B EDG service water inlet isolation valve failed to open within its allowed time period during a technical specification surveillance test. Operators appropriately declared the diesel inoperable and initiated a work order to troubleshoot the problem. The work order was finalized and tags were hung at 3:31 p.m. to commence work. However, the work was not authorized to begin until 10:40 p.m., a delay of about seven hours. Additionally, after work completion, the tag release was authorized at 11:53 p.m., but the tags were not cleared until 2:12 a.m. the next morning, resulting in another two-hour delay. The EDG retest was completed at 3:19 a.m. on March 19.

The inspectors agreed with PSE&G's subsequent assessment that oversight of this emergent work item was weak. PSE&G documented this issue in a corrective action request and concluded that the primary cause for the ineffective management was the lack of an established single point of contact to coordinate the work. Additionally, operations and maintenance personnel were insensitive to the urgency of returning safety equipment to an operable status, and the need to minimize unavailability time for maintenance rule requirements.

2B EDG Outage:

At 5:47 a.m. on April 14,1998, operators removed the 2B EDG from service for planned on-line maintenance. PSE&G developed an LCO maintenance plan for this outage in accordance with procedure SC.SA-SD.ZZ-0011(Z), *"Work Management Manual* (WMM)." The inspectors noted that the content of the plan was thorough and met the standards of the WMM, including an assessment of the plan's impact on both overall plant risk and maintenance rule performance criteria.

PSE&G planning personnel recognized about 11 hours after the on-line outage began that EDG service water (SW) valves were inappropriately tagged and the heat exchanger drained. Plant operators were promptly informed after discovery of this issue. Specifically, a biofouling inspection of the SW jacket water/lube oil heat exchanger was originally planned as part of EDG outage work scope, but was later removed from the scope three weeks prior to the work. This change in scope was not effectively communicated to the operations department staff, and as a result, the EDG SW system was unnecessarily tagged out and drained, delaying the implementation of other necessary work. Additionally, the Salem staff also determined that appropriate fire protection impairments had not been prepared for the SW outage, nor was there a scheduled activity for a required jacket water chemistry sample. These issues further delayed the completion of this non-required work activity.

The inspectors observed various individual maintenance activities conducted during the outage and noted that workers used approved procedures, had copies of work orders and prints at the work site, and maintained work areas in a neat and orderly manner. Temporarily installed scaffolding was structurally sound and had the required permit attached. The inspectors observed that work supervisors frequently toured the work area.

On April 15, PSE&G personnel identified an equipment tagging "near miss" during the 2B EDG outage. Specifically, the day shift I&C supervisor received a turnover from the night supervisor that a partial tag release could be executed for a diesel control power breaker. This breaker had a red blocking tag attached due to various electrical work being performed. The supervisor authorized the temporary release without reviewing all activated work orders that were in progress. At the time, I&C technicians were performing maintenance activities which were protected by this tag. An alert electrical supervisor monitoring work in the 2B EDG room observed the I&C work in progress and stopped the operator from releasing the tag.

The inspectors noted that PSE&G's administrative procedure NC.NA-AP.ZZ-0015, "*Safety Tagging Program,*" requires that "responsible individuals ensure that personnel protected by safety tags are notified and clear of the equipment when authorizing a tag release." The inspectors concluded that the failure to implement this step of the procedure was a violation of TS 6.8.1, which requires that procedures be implemented for control of safety-related equipment. PSE&G corrective actions for this event included counseling the individuals involved in the improper tagging release, and re-emphasis on the need for tagging process adherence to craft personnel during a weekly department meeting. This self-identified and corrected violation is being treated as a Non-Cited Violation consistent with Section VII.B.1 of the NRC Enforcement Policy. **(NCV 50-311/98-03-01).**

All pre-planned 2B EDG maintenance was completed at 1:12 a.m. on April 16, yet blocking tags were not removed until about 9:00 a.m., resulting in another eight hour delay. The inspector noted that there was no clearly designated coordinator of the LCO plan to ensure its timely completion. Also, operators were not sufficiently sensitive to the priority of returning the 2B EDG to an operable status, and as such did not pursue blocking tag removal in a timely manner. This unnecessarily delayed post-maintenance testing, and resulted in the 2B EDG not being returned to operability until 5:18 p.m. on April 16. The actual overall outage duration was 59 hours, or 82% of the 72-hour TS allowed outage time (AOT), while the planned duration was 60% of the AOT. PSE&G management understood and recognized that this on-line maintenance would result in exceeding the 2B EDG maintenance rule performance criteria, however, the noted delays unnecessarily extended the diesel's unavailability. The 2B EDG will now be classified category a(1) under the maintenance rule, which requires that specific performance goals be established and monitored.

PSE&G management also recognized the poor execution of the 2B EDG planned outage and aggressively implemented corrective actions. A level two action request was initiated to evaluate the inadequate preparation for and execution of the work. An outage critique was held on Friday, April 17, to capture lessons learned, especially since the 2C EDG was scheduled for a similar outage the following week. Additionally, the planning supervisor issued a memorandum with specific expectations for the preparation and implementation of LCO maintenance plans, including the formation of work week teams to oversee LCO maintenance, deadlines for plan and prerequisite signoffs, and specific guidance concerning tagging implementation.

2C EDG Outage:

Operators removed the 2C EDG from service at 5:46 a.m. on April 21, 1998 for planned on-line maintenance. "Critical path" for the outage was equipment calibration by I&C personnel. This work was turned over to the "12-hour shift" maintenance crew so that the work could be pursued around the clock. However, the 12-hour crew was not familiar with the scheduled instrument calibration procedures and required assistance from day shift I&C technicians who were. Additionally, the 12-hour shift technicians were diverted from the critical path work to assist in maintenance on a boric acid transfer pump, for which there was no TS limiting condition for operation. Further, the commencement of work was delayed about three hours due to tagging inefficiencies. Overall PSE&G determined that these delays resulted in a 2C EDG outage duration of 59 hours instead of the scheduled 42 hours.

PSE&G management recognized the noted deficiencies during the conduct of a critique of the 2C EDG planned maintenance and initiated an action request to document the assessment. Corrective actions were still being developed at the conclusion of the inspection report period.

c. Conclusions

PSE&G determined that the lack of clear ownership for and coordination of recent emergency diesel generator (EDG) on-line maintenance outages resulted in unnecessary delays in work completion, extending the overall equipment unavailability time. Inadequate tagging controls during the 2B EDG outage resulted in an electrical breaker blocking tag being released while personnel were actively working on equipment supplied by that breaker.

M2 Maintenance and Material Condition of Facilities and Equipment

M2.1 11 Auxiliary Feedwater Pump Minimum Flow Line Leak

a. Inspection Scope (92902, 92903)

On March 14, 1998, an equipment operator identified a through-wall leak on the discharge weld of the 11 auxiliary feedwater (AFW) pump minimum-flow line orifice. The inspectors reviewed PSE&G's actions to correct this degraded condition and ensure that redundant trains of equipment were not similarly degraded.

b. Observations and Findings

PSE&G determined that the leak from the 11 AFW orifice was approximately 25-30 drops per minute on the outlet of the minimum-flow orifice, where a stainless steel coupling is welded to the downstream carbon steel pipe. When the leak was discovered, the 11 AFW pump was in service, but was not required to be operable in accordance with technical specifications (TS). Engineers determined that the root cause of the leak was cavitation at the discharge of the minimum-flow orifice.

Technicians repaired the 11 AFW orifice weld and examined the equivalent piping for the 12 AFW pump by using ultrasonic testing. Since these results were acceptable, Unit 1 operators proceeded with a mode change from mode 4 to 3, an operating condition which requires AFW to be operable. Subsequently, engineers recommended a radiographic test of the 12 AFW line to provide a clearer picture of the affected area of pipe. This test revealed that the wall thickness on the 12 AFW pipe was .085 inches, less than minimum wall thickness of .147 inches, contrary to the earlier ultrasonic examination. Operators declared the 12 AFW train inoperable and entered the 72-hour TS 3.7.1.2.a action statement to initiate repairs.

PSE&G technicians also performed an ultra-sonic test of the same piping for the 22 AFW (Unit 2) pump. This inspection revealed an acceptable wall thickness of .235 inches, and no cavitation damage like that found on the Unit 1 pumps, likely due to the fact that the Unit 2 AFW pumps are newer and have less run time than the Unit 1 pumps. Also, PSE&G design engineering performed a calculation which showed that .040 inches of wall thickness was sufficient to withstand the design pressure at the orifice outlet. Based on this information, inspections of the 21 and 23 AFW pumps were scheduled for August and September 1998, respectively.

Based on the activities associated with the 11 AFW pump orifice leak, PSE&G determined that only the steam-driven AFW pump (13 and 23) discharge piping was included in the FAC program. However, the motor-driven pumps had greater run times since they are normally operated during unit shutdowns. PSE&G revised the FAC program scope to include monitoring all the AFW pumps discharge and minimum flow line piping.

c. Conclusions

PSE&G implemented appropriate corrective actions to repair degraded auxiliary feedwater piping revealed by a through-wall leak on a pump minimum-flow orifice line. Technical specification and ASME code class 3 requirements were satisfied. However, this event revealed a weakness in scope of the flow-accelerated corrosion program in that only the steam-driven pumps were included for monitoring.

M8 Miscellaneous Maintenance Issues

M8.1 (Closed) VIO 50-272&311/96-08-02,96-08-03, 50-311/96-18-02

a. Inspection Scope (92702)

Based on an on-site review and verification of corrective actions, the inspectors assessed PSE&G's response to the previously-cited violations described below..

b. Observations and Findings

VIO 50-272&311/96-08-02: failure to perform post maintenance testing (PMT). In a letter dated September 9, 1996, PSE&G attributed the cause of this violation to personnel error and improper procedure use for controlling PMT work. In response, Salem staff reviewed the event with maintenance personnel and revised the work management desk guide, SC.MD-DG.Z-0001(Z), to clarify PMT requirements. The inspector reviewed the revised desk guide and determined that the corrective action was implemented. This item is closed.

VIO 50-272&311/96-08-03: inadequate safety-related material storage. In a letter dated September 9, 1996, PSE&G attributed the cause of this violation to a failure to follow procedures and inadequate implementation of management expectations. In response, Salem staff revised the material handling procedure, NC.NA-AP.ZZ-0018(Q), to add sufficient detail regarding the proper storage of material. The staff also completed a follow up self assessment in October 1996, which verified that personnel were properly storing material. The inspector reviewed the results of the assessment and the noted procedure revision and determined that these corrective actions were reasonable. This item is closed.

VIO 50-311/96-18-02: lack of containment closure during refueling. In a letter dated March 20, 1997, PSE&G attributed the cause of this violation to inadequate implementation of outage scheduling and risk management requirements. In response, PSE&G staff implemented a continuing training program on outage risk management, to be administered to outage management and planning and scheduling personnel. The staff also revised the containment closure procedure, S1/S2.OP-ST.CAN-0007, to incorporate the posting of penetration areas to restrict work in those areas during core alterations, and to provide clarification of criteria for determining that a system is intact. The inspector reviewed the training program and procedure revisions and determined that these corrective actions were appropriate. This item is closed.

VIO 50-311/97-14-03: failure to follow technical specification 6.8.1 procedure. The inspectors reviewed PSE&G's response to the Notice of Violation (NOV), dated September 12, 1997, regarding test equipment left installed on the 2A emergency diesel generator. Licensee Event Report 50-272/97-013-00, also describes the circumstances and corrective actions associated with this issue. See section M8.2 below for the inspector's review and assessment.

c. Conclusions

PSE&G responses to the previously-identified issues were timely and reasonable. The inspectors verified that all committed actions were completed.

M8.2 (Closed) LER 50-272/97-013-00: failure to meet technical specification 3.8.1.1 action b

a. Inspection Scope (92700, 92901, 92902, 92903)

On July 2, 1997, following surveillance testing, the 2A emergency diesel generator (EDG) was inappropriately declared operable with electrical test equipment still installed in the EDG control cabinet. This issue was discussed in NRC Inspection Report 50-272 & 311/97-14 and dispositioned as a cited violation. The inspectors performed an on-site review the corrective actions specified in this licensee event report (LER).

b. Observations and Findings

After this issue was identified, a follow-up surveillance test was performed satisfactorily, and the test equipment was removed. PSE&G attributed the cause of this event to human error. Operators did not perform the surveillance test restoration completely, in that they left test equipment connected to support subsequent work. Station administrative procedures allow omitting procedure steps (i.e. marking them "not applicable"), if the partial performance does not change the intent of the procedure. In this case, the intent of the procedure was changed because the pre-test condition was not fully restored. Following this event, Salem management re-emphasized the expectations concerning procedure use to all plant personnel. The inspectors determined that the operations department guidance for procedure use was revised to require the concurrence of two operators, at least one of whom shall be a supervisor, before a procedure step is determined to be "not applicable."

Additionally, the EDG surveillance test equipment was modified by installing safety-related fuses to separate the Class IE equipment from the test equipment. The inspector reviewed and discussed the fuse selection calculation with Salem design engineering personnel and did not note any problems. Adequate controls were established for maintaining safety-related fuses in the test equipment. The inspectors also reviewed the 10 CFR 50.59 safety evaluation for considering the EDG system operable with temporary test equipment connected. The safety evaluation was adequate. This LER is closed.

c. Conclusions

Corrective actions taken to address the deficiencies identified following the improper restoration of a Unit 2 emergency diesel generator were adequate. Associated design calculations and safety evaluations were thorough.

III. Engineering

E1 Conduct of Engineering

E1.1 22 Steam Generator Steam Flow Transmitter (Update)

a. Inspection Scope (92902, 92903)

The failure of the 22 steam generator (SG) steam flow transmitter for channels II and III was documented in NRC Inspection Report (IR) 97-18 and updated in IR 97-21. The inspector followed up on subsequent licensee actions to correct this persistent problem.

b. Observations and Findings

PSE&G technicians replaced the low side sensing line during the recent Unit 2 forced outage. Inspection of the old sensing line revealed that the drain hole which carries condensation back to the main steam line was plugged with debris. PSE&G concluded that this was evidently the root cause for the high steam flow indications which these channels had been exhibiting. Operators monitored these channels after returning Unit 2 to power operation and noted normal indications, consistent with other steam flow channels. The channels were successfully tested by a special test procedure to ensure that they would respond appropriately to power changes. PSE&G then restored the channels to operation, and removed the forced values to the digital feed water system.

c. Conclusions

PSE&G restored the 22 steam generator steam flow channels II and III to an operable status in a slow and deliberate manner, meeting all technical specification requirements during the process.

IV. Plant Support

P1 Conduct of Emergency Preparedness (EP) Activities

P1.1 Effectiveness of Licensee Controls in Identifying, Resolving and Preventing Problems

a. Inspection Scope (82701)

The inspectors reviewed PSE&G's process for identifying, tracking and resolving EP-related items.

b. Observations and Findings

The EP staff utilized an automated corrective action tracking system maintained by the Quality Assurance group. PSE&G used the system as a mechanism for reporting conditions requiring corrective action, program enhancement and drill/exercise issues. The program was maintained by the EP Corrective Action Coordinator who tracked items and ensured corrective actions were timely and adequate. This was a good initiative because prior to mid-1997, the EP staff used several different tracking systems. It was evident during this inspection that having one system with a dedicated coordinator provided continuity and immediate attention, and provided EP management with continual oversight of EP-related open items.

While reviewing past action item reports, the inspectors noted that some of the issues discussed in the previous NRC inspection had not been resolved in a timely manner. For example, a lapse in respirator qualifications was identified by the NRC in late 1996 and the issue, although improved, was not yet fully resolved. The backup diesel generator located in the Emergency Operations Facility (EOF) has been found to be inadequately maintained in the past two internal audits. Also, Emergency Action Level (EAL) charts were not adequately updated to reflect the NUMARC EAL classification scheme because of a burdensome review and approval process. PSE&G personnel acknowledged these had to be coordinated with other departments for resolution, and planned to better prioritize issues that required resolution.

Additionally, PSE&G's EP Self-assessment program had improved and was deemed effective. Since January 1, 1997, PSE&G completed nine self-assessments. A review of the corrective actions associated with the self-assessment findings indicated that they were properly tracked and trended, and that corrective actions were being effectively implemented to resolve programmatic weaknesses.

c. Conclusions

Based upon the review of selected items and procedures, the inspectors concluded that PSE&G's method for tracking EP corrective actions was very good and that the EP self-assessment program provided good feedback to the staff. The timeliness of resolving some identified issues was weak.

P2 Status of EP Facilities, Equipment, Instrumentation and Supplies

a. Inspection Scope (82701)

The inspectors conducted an audit of emergency equipment in the control room, the operations support center (OSC), the technical support center (TSC), and the emergency operations facility (EOF) to assess facility readiness. Also, the inspectors reviewed documentation of equipment surveillance tests conducted since the last EP program inspection for completeness and accuracy.

b. Observations and Findings

EP equipment checklists were maintained accurately. Radiological survey instruments at the facilities were all within the designated calibration period. The inspectors reviewed equipment surveillance tests and inventory checklists and determined that they were completed as required, and that any discrepancies were resolved in a timely manner. The inspectors reviewed the monthly communication test records and determined that Emergency Response Organization responders were timely and that EP management was proactive in retrieving station badges if a responder failed to reply. PSE&G recently switched pager vendors and problems have been identified in which not all the pagers activated when required. PSE&G staff indicated that in these cases PSE&G verified that PSE&G would be able to minimally staff the emergency facilities if activated at that time. Resolution of this issue was being actively pursued.

The inspectors toured the new combined Hope Creek/Salem OSC and EOF. The facilities were enlarged and the layout was much improved for accommodating the needs of the emergency responders. PSE&G plans to combine the Hope Creek/Salem technical support centers in 1999. These enhancements demonstrated PSE&G's commitment to support the EP function.

Additionally, the inspectors determined through document reviews and discussions with EP staff that the siren system was properly maintained and tested as required by the Emergency Plan (E-Plan) and applicable procedures. Work orders generated due to equipment malfunctions were tracked to completion and once a work request was initiated, repairs were completed within 24-48 hours.

c. Conclusions

The emergency preparedness facilities and equipment were in a good state of operational readiness. Surveillance tests and inventories were performed as required and discrepancies were resolved in a timely manner. Expenditure of resources to improve equipment and facilities demonstrated PSE&G's commitment to support and maintain the EP program. Overall, the inspectors considered this area to be very good.

P3 EP Procedures and Documentation

a. Inspection Scope (82701)

The inspectors assessed the process which PSE&G used to review and change the E-Plan and implementing procedures (EPIPs). The inspectors also reviewed recent EPIP/E-Plan changes to assess the impact on the effectiveness of the EP program. Further, the inspectors verified that appropriate letters of agreement were in place with offsite emergency agencies.

b. Observations and Findings

The inspectors assessed the 10 CFR 50.54(q) (effectiveness review) process for E-Plan changes and the annual E-Plan review process performed by the licensee. The reviews were thorough, and met NRC requirements as well as commitments made in the Updated Final Safety Analysis Report (UFSAR) and the E-Plan.

The inspectors conducted an in-office review of recent EPIP/E-Plan changes and found the EPIPs lacked detail and clarity, and that paragraphs had been inadvertently removed during the revision process. Also, the inspectors determined that PSE&G was not routinely reviewing the EPIPs to ensure they were consistent with E-Plan requirements and adequately described the current program. In addition, the inspector often found it difficult to determine the adequacy of changes because the changes were not always identified and the basis for the change was not easily understood. The EP Manager stated that an action item had been initiated to completely rewrite the procedures for improving understanding and for conformance with other station procedures. Also, PSE&G added an item to the corrective action system to ensure that procedures will be reviewed on a biennial basis. Also, changes would be prominently identified and explained when sent to the NRC for review. The inspectors had no further questions.

The inspectors verified that agreement letters with offsite agencies and support organizations were valid or were updated as required per the E-Plan.

c. Conclusions

PSE&G emergency plan changes were adequately reviewed in accordance with 10 CFR 10.54(q). PSE&G planned to review, evaluate/rewrite the emergency plan implementing procedures for conformance to other station procedures and to improve the review process. The inspectors also concluded that letters of agreement with offsite agencies were in place.

P5 Staff Training and Qualification in EP

a. Inspection Scope (82701)

The inspectors reviewed EP training records, training procedures, and the E-Plan training requirements to evaluate PSE&G's emergency response organization (ERO) training program.

b. Observations and Findings

The inspectors determined through a review of training lesson plans, training record reviews, and discussions with ERO members, that the required EP training was conducted in accordance with PSE&G's E-Plan and applicable procedures. The inspectors randomly selected 60 training records for the ERO staff and found that the qualifications were current. Additionally, the inspectors reviewed the initial and requalification EP lesson plans for fire brigade and security personnel and determined, by a review of test documentation, that both organizations conducted EP training in accordance with applicable procedures.

The inspectors verified that the required drills were conducted to evaluated medical, radiation monitoring, and fire response. Since the last program inspection, PSE&G increased the number of quarterly drills to 12, in addition to monthly tabletop training for the operators. The PSE&G staff stated that the additional drills allowed them to focus more on teamwork, and critique documentation indicated an overall improvement in ERO performance. Also, the inspectors interviewed several Senior Reactor Operators from both Hope Creek and Salem, and found that they spoke positively of the additional table top drills because the repetitiveness provides them with more confidence in making emergency classifications using the new NUMARC Emergency Action Level (EAL) scheme, implemented in January 1997.

c. Conclusion

PSE&G conducted emergency response training and drills as required. Based upon overall good performance during the drills and the March 1998 biennial full-participation emergency exercise, the inspectors concluded that training for the ERO was effective.

P6 EP Organization and Administration

a. Inspection Scope (82701)

The inspectors reviewed PSE&G's EP department staffing and management to determine what changes had occurred since the last program inspection and whether those changes had any adverse effect on the EP program.

b. Observations and Findings

Since the last NRC EP program inspection in August 1997, the EP program was split from the radiation protection department and combined with corrective actions and instructional technology departments. In March 1997, PSE&G hired a new EP manager who has a broad knowledge of EP. Recently the EP section was fully staffed with nine individuals. This included the addition of a supervisor for handling offsite agency issues and two coordinators for corrective actions and training oversight. This initiative was deemed to be good because it provided better program ownership. Each supervisor was given a staff to support their mission. Also, the Director of EP/Training, reports directly to the PSE&G Chief Nuclear

Officer and President who appeared to be very supportive of the EP program and its management.

c. Conclusions

The department reorganization and hiring of a manager with extensive EP experience enhanced the EP program. The inspectors concluded that the positive findings during this inspection were an indication that the program had significantly improved since the last inspection.

P7 Quality Assurance in EP Activities

a. Inspection Scope (82701)

The inspectors reviewed the 1996 and 1997 Quality Assurance (QA) audit reports of EP to assess the effectiveness of the audits of the EP program.

b. Observations and Findings

During an interview with the lead QA auditor for the last EP-evaluation conducted from November 3 to December 5, 1997, the inspectors determined that PSE&G had expended significant resources to conduct the audit. Specifically, the audit consisted of several person-weeks of effort and included an independent technical specialist. The inspectors reviewed the 1997 audit plan and checklists, which covered 10 CFR 50.54(t) requirements, commitments in the E-Plan, and the guidance in NUREG-0654, "Criteria for Preparation and Evaluation of Radiological Emergency Response Plans and Preparedness in Support of Nuclear Power Plants". The checklist used to implement the audit plan for the 1997 audit was thorough. The 1996 and 1997 audit reports were of sufficient scope and depth to assess the EP program, and addressed the areas specified in 10 CFR 50.54(t). Numerous recommendations for program enhancement resulted. The recommendations were not indicative of programmatic weaknesses and were incorporated by the EP department. The inspectors verified that offsite officials were provided copies of the audit report section pertaining to PSE&G's interface with offsite agencies and that the reports were distributed to the appropriate licensee management.

c. Conclusions

Quality Assurance audits of the emergency preparedness (EP) program were thorough and the reports were useful to PSE&G management in assessing the effectiveness of the EP program and providing enhancement recommendations. This area was assessed as excellent.

S8 Miscellaneous Security and Safeguards Issues

S8.1 Operational Security Response Evaluation for Hope Creek and Salem

NRC headquarters and regional inspectors conducted an on-site Operational Security Response Evaluation at both the Hope Creek and Salem generating stations from April 20, 1998 to April 24, 1998. The findings of this inspection will be documented in NRC Inspection Report 50-272, 311, and 354/98-201.

F8 Miscellaneous Fire Protection Issues

F8.1 Fire Protection Inspection for Hope Creek and Salem

Region-based inspectors performed an inspection of the adequacy of the fire protection program at the Hope Creek and Salem generating stations from March 23, 1998 to March 27, 1998. The findings of this inspection were documented in NRC Inspection Report 50-354/98-02 for Hope Creek.

V. Management Meetings

X1 Exit Meeting Summary

The inspectors presented the inspection results to members of licensee management at the conclusion of the inspection on May 11, 1998. The licensee acknowledged the findings presented.

The inspectors asked the licensee whether any materials examined during the inspection should be considered proprietary. No proprietary information was identified.

INSPECTION PROCEDURES USED

IP 37551:	Onsite Engineering
IP 40500:	Effectiveness of Licensee Controls in Identifying, Resolving, and Preventing Problems
IP 61726:	Surveillance Observations
IP 62707:	Maintenance Observations
IP 71707:	Plant Operations
IP 71750:	Plant Support Activities
IP 82701:	Operational Status of the Emergency Preparedness
IP 90712:	In-office Review of Written Reports of Nonroutine Events at Power Reactor Facilities
IP 92700:	On-site Followup of Written Reports of Nonroutine Events at Power Reactor Facilities
IP 92702:	Followup on Corrective Actions For Violations and Deviations
IP 92901:	Plant Operations Followup
IP 92902:	Maintenance Followup
IP 92903:	Engineering Followup
IP 92904:	Plant Support Followup
IP 93702:	Event Followup

ITEMS OPENED, CLOSED, AND DISCUSSED

<u>Opened/Closed</u>

50-311/98-03-01	NCV	Failure to implement procedure step in safety tagging program
50-272&311/98-81-01	NOV	Failure to implement action request procedure
50-272&311/98-81-02	NOV	Failure to implement corrective action procedure

<u>Closed</u>

50-272&311/96-08-02	VIO	Failure to perform post maintenance testing.
50-272&311/96-08-03	VIO	Inadequate safety-related material storage.
50-311/96-18-02	VIO	Lack of containment closure during refueling.
50-311/97-03-02	IFI	Management of commitment process.
50-311/97-07-01	VIO	Failure to establish containment integrity within eight hours.
50-311/97-14-03	VIO	Improper restoration of emergency diesel generator following testing.
50-272/97-013-00	LER	Failure to meet TS 3.8.1.1 Action B
50-272/98-002-00	LER	Auxiliary building excess flow damper found wired open with spring removed
50-272/98-002-01	LER	Auxiliary building excess flow damper found wired open with spring removed

LIST OF ACRONYMS USED

AFW	Auxiliary Feedwater
AOT	Allowed Outage Time
CAL	Confirmatory Action Letter
CFCU	Containment Fan Coil Unit
E-Plan	Emergency Plan
EAL	Emergency Action Level
EDG	Emergency Diesel Generator
EOF	Emergency Operations Facility
EP	Emergency Preparedness
EPIP	Emergency Preparedness Implementing Procedure
ERO	Emergency Response Organization
FAC	Flow-Accelerated Corrosion
LCO	Limiting Condition For Operation
LER	Licensee Event Report
NRC	Nuclear Regulatory Commission
OSC	Operations Support Center
PDR	Public Document Room
PMT	Post Maintenance Testing
PSE&G	Public Service Electric and Gas
QA	Quality Assurance
RATI	Restart Assessment Team Inspection
SAP	Salem Assessment Panel
SG	Steam Generator
SGFP	Steam Generator Feed Pump
SW	Service Water
TS	Technical Specifications
TSC	Technical Support Center
UFSAR	Updated Final Safety Analysis Report
VDC	Volt DC
WMM	Work Management Manual