U. S. NUCLEAR REGULATORY COMMISSION

REGION I

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Licensee:	Public Service Electric and Gas Company
Facility:	Salem Nuclear Generating Station, Units 1 & 2
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EXECUTIVE SUMMARY

Salem Nuclear Generating Station
NRC Inspection Report 50-272/97-21 and 50-311/97-21

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

Operations

Unit 1 activities were conducted in a more controlled manner than during the previous inspection period. Plant operators performed well during the Unit 1 drain down to mid-loop and the vacuum fill of the reactor coolant system. Stable plant conditions were cautiously maintained during the prolonged effort to calibrate the narrow range mid-loop level indicators.

In two instances, operators failed to comply with the established procedures for configuration control. This non-compliance led to plant operators exceeding the time limit established by plant technical specifications for an inoperable Unit 2 chiller. PSE&G has initiated actions to address weaknesses in configuration control.

The actions taken by the licensee to restore the operability of an auxiliary building ventilation damper were timely and adequate. However, the licensee failed to promptly identify the reporting requirements specified in 10CFR50.72.

The licensee had an adequate plan for completing procedure revisions necessary for Unit 1 restart and to reduce the procedure revision backlog.

The licensee continued to make progress in reducing the number of operator work arounds and control room deficiencies and was actively working to minimize the number of deficient conditions and was adequately assessing the aggregate impact of these conditions.

Maintenance

Unit 1 refueling activities were controlled and conducted in a safe manner, and communication between personnel involved was good.

The licensee met all technical specification requirements for the 2B emergency diesel generator (EDG) failure. Appropriate trouble-shooting activities were performed using an approved system engineering action plan. The apparent cause of the 2B EDG failure was a defective oiler resulting in insufficient lubrication to the B train air start motors. The licensee is continuing its investigation of the failure mechanism.

A sizable corrective maintenance backlog exists for both Salem units. A backlog reduction plan has been developed with goals that the licensee believes can be attained without

impact on plant safety and maintenance resources. Additionally, the licensee has established an adequate program for monitoring the effectiveness of the backlog reduction plan. The inspector concluded that the Salem staff addressed the corrective maintenance backlog.

Engineering

The licensee's removal of insulation from the 23 steam generator (SG) sensing line was a well-planned and coordinated evolution, but was not successful in determining the root cause of the 22 SG transmitter failure.

The licensee made significant improvements to the station air compressors (SACs) to improve their reliability.

The licensee has taken acceptable actions to address testing of Unit 1 molded case circuit breakers. However, the licensee had failed to perform surveillance testing of a Unit 2 electrical containment penetration molded-case circuit breaker as required by the Technical Specifications.

The Inservice Test Program for Unit 1 residual heat removal system was implemented effectively and acceptable for plant startup.

The licensee enhanced the Unit 1 steam dump valve performance and implemented related emergency operating procedure changes to address the issue of emergency operating procedure technical adequacy. The Unit 2 steam dump valves performed adequately during restart testing.

The licensee has implemented appropriate corrective actions to address the longstanding reliability issues associated with the Unit 1 positive displacement charging pump.

Previously identified pipe support concerns have been properly corrected by a combination of reanalyses and modifications.

The licensee acceptably addressed Integrated Performance Assessment Team identified separation issues and acceptably corrected the deviations to conform to the revised criteria.

The licensee took appropriate actions to resolve power operated relief valve (PORV) seat leakage problems. Since the new PORV trim sets have been tested greatly in excess of their cyclic design requirements with no significant leakage, there is reasonable assurance that the previous leakage problems have been corrected.

The licensee has taken appropriate actions to provide reasonable assurance that the current design, operation, and testing of the PORVs and their associated accumulators is adequate to ensure the ability of Salem Unit 1 to cope with an Inadvertent safety injection Initiation Event.

Licensee modifications and stroke time testing of gate valves susceptible to pressure locking and thermal binding were acceptable. However, some of the licensee's reviews of the Valve Operation Test and Evaluation System (VOTES) test results were not acceptable.

The licensee took appropriate steps to improve the performance of the Unit 1 radiation monitor system. Where design was deficient, they implemented modifications to rectify the deficiencies.

The corrective actions taken to correct Unit 1 safety injection pump deficiencies were effective. The licensee adequately demonstrated satisfactory safety injection pump performance.

The installation of the flow resistance orifices was effective in mitigating cavitation in the cold and hot leg injection lines, and providing pump runout protection for the charging and safety injection pumps. The design change package had been properly implemented and the post modification testing was adequate.

The corrective actions to resolve auxiliary feedwater performance issues were acceptable.

The licensee took effective actions to correct deficiencies in the emergency operating procedures (EOPs) and plant design documents regarding the switch over of emergency core cooling system (ECCS) pumps to cold and hot leg recirculation.

The licensee adequately completed the modification installation and testing of the Unit 1 containment fan coil units to address potential water hammer and two phase flow conditions. In addition, adequate measures to ensure freeze protection have been taken.

Although the quantity of backlogged engineering activities is large, the licensee was properly managing and prioritizing the activities.

The licensee has taken appropriate actions to address weaknesses previously identified in the Vendor Manual Program. Specifically, the licensee has implemented a more rigorous vendor recontact program, they have significantly reduced the backlog of vendor documents onsite requiring processing, and they have developed a performance indicator to track and manage the backlog and are evaluating the need for additional performance indicators.

The licensee Quality Assurance department performed a broadly based and probing assessment of the Salem inservice test (IST) program. The corrective actions for the audit findings were prompt and effective. Tracking and trending of component performance was an IST program strength.

Although the licensee's performance improvement requests written to address potentially unanalyzed breaker lineups and inadequate breaker coordination properly addressed the NRC questions with these issues, the licensee's actions, when these issues were originally identified, were not timely.

Plant Support

The licensee's exposure control program continues to emphasize the control of individual exposures.

Dosimetry discrepancies were, in some cases, non-conservatively dispositioned for personnel exposure record purposes. In all these cases, only minor exposures were involved. The lack of exposure discrepancy investigation guidance is being addressed by the licensee to strengthen this program area.

Excellent contamination control practices at Salem and Hope Creek stations have resulted in no reported internal exposures. The internal exposure program capability has begun to improve. Further hardware and software upgrades are planned for early 1998.

All required radiological postings and locked areas were within regulatory requirements and the areas were clear of unnecessary equipment and free of safety hazards. Several minor posting weaknesses were observed indicating the need for continued diligence in this area.

The licensee's electronic dosimeter calibration program was effectively implemented in accordance with station procedures and regulatory requirements.

The licensee has self-identified significant weaknesses in the radiation protection (RP) technician continuing training program and taken appropriate short term corrective actions and identified long term plans to correct the identified deficiencies.

The RP program oversight consisted of a combination of a good Quality Assurance audit and surveillance programs, an effective radiological problem corrective action program, and self-assessment activities that provide meaningful performance review.

The licensee had a sound basis for the one-hour waiting period specified in the Event Classification Guide before initiating a one-hour report for loss of the Emergency Notification System.

In the past year, the licensee has made a concerted effort to improve their emergency drill response performance through the increased efforts of the Emergency Preparedness staff, additional training, and management support of the program. The improvement was evident during conduct of an off-hours unannounced drill.

The licensee had improved the oil collection capabilities of the Unit 1 RCP motors and provided reasonable assurance that a fire would not occur.

The licensee had properly completed the Unit 1 modifications to achieve electrical independence and isolation for post-fire alternative shutdown.

The licensee appropriately analyzed the hydraulic adequacy of the fire protection system to address additional hose lengths required for a standpipe hose station.

The fire protection deluge system flow control valve was properly sized and calibrated for its installed use.

The fire watches, used as a compensatory measure while the fire resistive capabilities remain undetermined for electrical raceway fire barrier systems, were knowledgeable of their duties and provided effective monitoring of assigned plant locations.

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Report Details

Summary of Plant Status

Unit 1 began the period in Mode 6, with core reload activities in progress. Core reload was completed on December 4, and Mode 5, Cold Shutdown, was entered on December 11. The unit remained in Mode 5 through the end of the inspection period.

Unit 2 began the period operating at 100% power. On December 21, 1997, operators commenced a power reduction to make repairs to a steam leak from a heater drain valve. On December 22, the main generator was taken off line to perform main turbine valve testing. Reactor power was restored to 100% on December 26. On January 1, 1998, a main generator stator water runback occurred, which reduced reactor power to 19%. Following troubleshooting and repair activities, the reactor was returned to 100% power on January 3 and remained at that power level through the remainder of the period.

I. Operations

O1 Conduct of Operations (71707, 92901, 93702 & 40500)

O1.1 General Comments

Using Inspection Procedure 71707, the inspectors conducted frequent reviews of ongoing plant operations. In general, the conduct of operations was professional and safety-conscious. Unit 1 activities were conducted in a more controlled manner than during the last inspection period. Operation of Unit 2 continued to be very good. In addition, a "black board" was achieved for Unit 2 control room overhead annunciators in January 1998. Specific events and noteworthy observations are detailed in the sections below. In addition, conduct of refueling activities is further discussed in Section M1.2.

O1.2 Mid-loop Operations (Unit 1)

a. Inspection Scope

The inspectors observed activities associated with reactor coolant system (RCS) drain down, mid-loop operation and restoration. The licensee established mid-loop conditions on Unit 1 to perform procedure S1.OP-SO.RC-0002, "Vacuum Fill of the RCS."

b. Observations and Findings

The inspectors noted that pre-evolution briefings were thorough and included discussion of compensatory actions for an unplanned loss of the residual heat removal (RHR) system at reduced RCS inventory. Plant operators cautiously performed the RCS drain down and vacuum fill evolutions and remained focused on key RCS parameters.

During the RCS vacuum fill, the licensee experienced problems with the narrow range mid-loop level indicators located in the control room. Vacuum filling operations were secured, and RCS level was monitored with a direct reading tygon tube level indicator located inside containment. Salem operations decided to maintain reduced RCS inventory conditions during the level sensor troubleshooting and calibration efforts. The inspectors noted that stable conditions were cautiously maintained during the prolonged effort to calibrate the level indicators and operations' supervision appropriately raised a concern about staying in the mid-loop condition while continuing the troubleshooting efforts. Following four shifts of troubleshooting, the narrow range mid-loop indicators were returned to service, and RCS filling and venting were completed without any additional problems.

c. Conclusions

Plant operators performed well during the drain down to mid-loop and the vacuum fill of the reactor coolant system. Stable plant conditions were cautiously maintained during the prolonged effort to calibrate the narrow range mid-loop level indicators.

O1.3 Failure to comply with Technical Specifications For Unit 2 Chiller (Closed) LER 50-311/97-17

a. Inspection Scope

During troubleshooting of the inoperable 23 chiller on December 12, 1997, Unit 2 control room operators noted that the non-essential heat loads were not isolated as required by Technical Specifications. The licensee issued Licensee Event Report (LER) 97-017-00 concerning this issue. The inspector reviewed the corrective actions specified in LER 97-017, and held discussions with operations personnel regarding this event.

b. Observations and Findings

On December 6, 1997, control room operators closed valves 1CH150, 2CH30, 1CH117, and 2CH151 to comply with Technical Specification Action Statement (TSAS) 3.7.10.a.1 for the inoperable 23 chiller. The TSAS requires that the non-essential loads be isolated within 4 hours. The operators did not update the Tagging Request and Inquiry System (TRIS) and did not hang information tags to identify the off normal position of these valves. On December 8, 1997, the common control area ventilation (CAV) system was placed in the maintenance mode, which also requires that valves 1CH150, 2CH30, 1CH117, and 2CH151 are closed. Unit 2 operators noted that the valves were already closed since the 23 chiller was still inoperable.

At 2:43 a.m. on December 11, 1997, Unit 1 control room operators restored the CAV system to the normal mode of operation. Valves 1CH150, 2CH30, 1CH117, and 2CH151 were opened. Unit 1 operators were not aware that the valves were required to be closed to meet the requirements of Unit 2 TSAS 3.7.10.a.1. At

2220 on December 12, 1997, during troubleshooting of the 23 chiller, Unit 2 control room operators recognized that valves 1CH150, 2CH30, 1CH117, and 2CH151 were open. The valves were immediately closed to comply with TSAS 3.7.10.a.1. The TRIS off normal database was updated, and the valves were appropriately tagged.

The remaining two operable chillers were evaluated by system engineering and determined to be capable of supplying all essential and non-essential chilled water loads with the existing heat load at the time of the event. Therefore, the event had no actual safety consequence. The operators initiated a significance level 2 action request (AR 971213050). The licensee attributed personnel error to the cause of this event. Control room operators failed to follow the requirements of procedure SC.OP-AP.ZZ-0103, "Component Configuration Control." Corrective actions remaining to be completed include revisions to the configuration control and CAV operating procedures to clarify requirements, and promulgation of lessons learned from this event to all operations personnel.

Configuration control problems have been previously noted in NRC Inspection Reports (IR) 50-272&311/96-08and 97-12. The licensee had initiated a significance level 1 action request (AR 971106245) in November of 1997, which identified an adverse configuration control trend. In addition, on January 30, 1998, control room operators opened breakers 2-INCOR-DRY1 and 2-INCOR-DRY2 to comply with TSAS 3.8.3.1.a, since the testing of their overcurrent trip function was in question. The operators failed to hang tags on these breakers to indicate their abnormal position, and failed to note their position in TRIS. The breakers were subsequently repositioned closed on February 3, 1998, by Reactor Engineering personnel without knowledge of the on-shift operators. In each of the above cases, operators failed to comply with station procedures for maintaining configuration control of safety related systems. Failure to comply with procedures is a violation of TS 6.8.1, which requires that written procedures be implemented for applicable procedures recommended in Appendix "A" of Regulatory Guide (RG) 1.33, Revision 2, February 1978. RG 1.33 recommends written procedures for equipment control of safety related systems. **(VIO 50-311/97-21-01)**.

c. Conclusions

Operators failed to comply with the established procedures for configuration control. This violation led to plant operators exceeding the time limit established by plant technical specifications for an inoperable chiller. PSE&G has initiated actions to address weaknesses in configuration control.

O2 Operational Status of Facilities and Equipment

O2.1 Auxiliary Building Ventilation System Damper Found Wired Open

a. Inspection Scope

Unit 1 Auxiliary building ventilation (ABV) system damper 1ABS8 was found wired open during system flow balance testing. The damper's safety function is to close during a high energy line break (HELB) to prevent a steam intake into the ABV exhaust plenum. The inspector reviewed the licensee's resolution of the problem and held discussions with system engineering, licensing, and corrective action personnel.

b. Observations and Findings

On December 17, 1997, the licensee discovered ABV system damper 1ABS8 wired open. The damper has a safety function to close during an HELB in the Unit 1 inner mechanical penetration area. Closing of the damper isolates the inner mechanical penetration area from the ABV exhaust plenum, thus preventing degradation of ABV exhaust charcoal and high efficiency particulate air (HEPA) filters. The wire restraint would have prevented damper 1ABS8 from performing its design safety function.

The licensee initiated a significance level 2 condition report (CR 971217315) to address this issue. Their evaluation determined that 1ABS8 was not wired open during the current refueling outage. Work order history indicated that the preventive maintenance (6 year frequency) was last performed on the damper in 1989, and the damper was properly tested at that time and operated freely. Insufficient work order history was available to identify other maintenance activities to determine when the damper was most likely wired open. The licensee implemented immediate corrective actions to restore the operability of 1ABS8. Inspections of other Unit 1 and 2 ABV dampers were performed to ensure that similar conditions did not exist elsewhere. The apparent cause for the event was attributed to personnel error associated with inadequate maintenance practices.

The licensee's initial review of CR 971217315 did not identify any reportability concerns. On January 20, 1998, during further evaluation of the CR, the licensee determined that this condition was outside the design basis of the plant and reportable under 10CFR50.73 as a Licensee Event Report. On January 23, 1998, the licensee, after being questioned by the inspector, initiated a non-emergency 4 hour event report under 10CFR50.72. The inspector concluded that the licensee's evaluation of reportability for this issue was not timely. On January 23, 1998, the licensee initiated an action request (AR 980130162) to address this issue. This failure to meet time requirements for reporting is a violation of minor significance and is being treated as a Non-Cited Violation, consistent with Section IV of the NRC Enforcement Policy. **(NCV 50-272/97-21-02)**

c. Conclusions

The actions taken by the licensee, during this inspection period, to restore the operability of the auxiliary building ventilation damper, 1ABS8, were timely and adequate. However, the licensee failed to promptly identify the reporting requirements specified in 10CFR50.72.

O3 Operations Procedures and Documentation

O3.1 (Closed) NRC Programmatic Restart Issue III.a.3.1: Adequacy and Use of Procedures (Unit 1)

a. Inspection Scope

The inspector reviewed the closure package for this item and interviewed licensee representatives concerning actions taken to reduce the procedure revision backlog. The inspector focused his review on licensee documentation concerning the operations and maintenance procedure backlog, including those revisions deemed necessary for Unit 1 restart. This issue was previously reviewed and closed for Unit 2 in IR 97-03.

b. Observations and Findings

The inspector found that the licensee had a manageable number of restart revisions, with a completion plan and sufficient resources to support entry into Mode 4. It also had a plan to reduce the remainder of the backlog once Unit 1 restart was complete. In addition, the inspector determined that the process for selecting procedures required for restart was effective and that the backlog was decreasing. The inspector concluded that the plan for revision reduction was adequate.

c. Conclusions

The licensee had an adequate plan for completing procedure revisions necessary for Unit 1 restart and to reduce the revision backlog. Therefore, Restart Issue III.a.3.1 is closed.

O8 Miscellaneous Operations Issue

O8.1 (Closed) NRC Programmatic Restart Issue III.8: Correction of Operator Work Arounds, Including Control Room Deficiencies (Unit 1)

a. Inspection Scope

Operator workarounds and control room deficiencies were addressed in NRC IR 96-18 for Unit 2. At that time the inspectors had determined that the operations staff had established adequate controls to identify, track, and correct operator workarounds and control room deficiencies. Operations and maintenance made significant progress in reducing the number of operator workarounds and control

room deficiencies. During this inspection, the inspector focused on reviewing the current status of the licensee's efforts to minimize the impact of operator work arounds and control room deficiencies for Unit 1 and Unit 2.

b. Observations and Findings

The inspector reviewed the licensee's restart package for this programmatic issue which was accepted by the General Manager - Salem Operations on December 17, 1997. In addition, the inspector reviewed procedure SC.OP-AP.ZZ-0030 which was revised in July 1997. This procedure describes the process of identifying, tracking, and managing Operator Deficiencies, which consist of control room indicators, out-of-service indicators, and operator work arounds. The inspector also reviewed the Operator Work Arounds and Control Room Indicators Monthly Impact Report for December, 1997 and January 1998, and the Operations Burdens Quarterly Impact Report for November 1997, and discussed the current status of Operator Deficiencies with licensee personnel and management.

As of January 9, 1998 there were 12 Operator Workarounds and 95 outstanding Control Room Deficiencies for Unit 1 and 8 Operator Workarounds and 46 outstanding Control Room Deficiencies for Unit 2. Although these numbers exceeded the licensee's goals of no more than 5 Operator Workarounds and no more than 30 Control Room Deficiencies per unit, the inspector found that the licensee has made significant progress in eliminating these conditions since January 1996. In addition, the inspector noted that pressurizer relief valve leakage for Unit 2 was not captured as a workaround, although, the inspector had previously heard licensee management discuss this issue as a work around condition. Operations personnel indicated that this was an oversight and that the work around condition would be added to the next status report. The inspector found that the licensee was actively working to minimize the number of operator work arounds and control room deficiencies and was adequately assessing the aggregate impact of these conditions.

c. Conclusions

The licensee continued to make progress in reducing the number of operator work arounds and control room deficiencies and was actively working to minimize the number of deficient conditions and was adequately assessing the aggregate impact of these conditions.

08.2 (Closed) LER 50-311/97-010-01: Technical Specification Required Shutdown due to Position Indication System Anomalies. This supplement to LER 97-10 was written to address additional information relative to the root cause determination. Since the plant shutdown was previously reviewed and discussed in NRC IR 50-272&31/97-15, and the LER was closed in NRC IR 50-272&311/97-18, the inspector performed an in-office review of this LER supplement. The inspector found that the additional issues discussed in the supplement agreed with her previous understanding of the issues and that no additional inspection effort was warranted. Therefore, this LER supplement is closed.

II. Maintenance

M1 Conduct of Maintenance (50001, 60710, 61726, 62707, 92902, & 40500)

M1.1 General Comments

The inspectors observed all or portions of the following work activities and Technical Specification surveillance tests:

•	W/O 970970237:	Replace RCP Vibration Monitors
•	W/O 971124222:	Reroute PRT Piping for RCS Leakage
•	W/O 971208089:	Insulation Removal on 23 SG Steam Flow Channel II
•	W/O 971030300:	2C EDG Watt Transducer/Indication Calibration
•	W/O 970206247:	EDG Jacket Water Cooler Inlet Air-operated Ball Valve
•	W/O 970827336:	13 AFP layup inspection
•	W/O 971231088:	22 CFCU service water inlet air operated valve repair
•	W/O 960608092:	Repair 22 SW pump 4KV breaker terminal block
•	W/O 971228014:	21 CP clean and repack couplings
•	SC.MD-PM.CS-0001:	12 CS pump mechanical seal replacement
•	SC.MD-PM.AF-0001:	Motor driven Byron-Jackson AFP disassembly, inspection, and reassembly - 12 AFP
•	S1.IC-ST.SSP-0002:	Solid State Protection System (SSPS) interface cabinet functional test
•	S1.OP-ST.DG-0002:	1B EDG Monthly Surveillance Test
•	S1.OP-ST.CVC-0004(Q):	Inservice Testing - 12 Charging Pump
•	S1.OP-SO.RC-0006(Q):	Draining the RCS to Less Than 101 Feet Elevation With Fuel in the Vessel
•	S2.OP-ST.AF-0003(Q):	Inservice Testing - 23 Auxiliary Feedwater Pump
•	S2.OP-ST.CH-0001(Q):	Inservice Testing - 21 Chilled Water Pump
•	S2.OP-ST.DG-0002(Q):	2B EDG Monthly Surveillance Test
•	S2.OP-ST.CS-0001:	21 CS pump 4.0.5P surveillance test

The inspectors observed that the plant staff performed the maintenance effectively within the requirements of the station maintenance program, and that the plant staff did the surveillances safely, effectively proving operability of the associated system. Minor deficiencies noted by the inspectors were promptly corrected by the licensee. Monthly surveillance testing of the 2B emergency diesel generator is further discussed in section M2.1 of this report.

M1.2 Conduct of Unit 1 Refueling Activities

The inspectors observed refueling operations to ensure that activities were controlled and conducted properly. Operating shift personnel conducted all refueling activities in accordance with Salem operations procedures and continuous control of core alterations was maintained by the control room operators. Formal three-way communications were used by all personnel involved with fuel movements. Operators remained focused on key plant parameters such as source range count rate, startup rate, and fuel pool water level. Core alterations were appropriately suspended to make repairs to fuel handling equipment. Adequate oversight of contractor refueling personnel was provided by Salem operations and reactor engineering staff, and proper radiological controls were maintained by radiation protection technicians. The inspectors concluded that Unit 1 refueling activities were controlled and conducted in a safe manner, and that communication between personnel involved was good.

M2 Maintenance and Material Condition of Facilities and Equipment

M2.1 Failure of 2B Emergency Diesel Generator (EDG) During Monthly Surveillance

a. Inspection Scope

The inspector followed up on the January 21, 1998 failure of the 2B EDG to start during the monthly surveillance test, S2.OP-ST.DG-0002. The 92-day train B air start motor test was also being conducted, with the A side air start motor isolated.

b. Observations and Findings

On January 21, 1998, operators attempted to start the 2B EDG during the monthly surveillance run, with the B train air start motors only (i.e., motors #1 and #4). The diesel failed to start in 10 seconds and thus tripped on "overcrank." When the licensee attempted a second start to duplicate the failure, the 2B EDG started with no abnormalities observed.

The licensee then continued troubleshooting efforts in accordance with its engineering action plan. Operators isolated the B train air start motors and successfully started the diesel using the A train. Then each air start motor was tested individually using the test pushbuttons on the diesel electrical panel. All motors met the acceptance criteria of greater than 50 rpm except the #1 motor, which rotated at 40 rpm. When this motor was opened for inspection, it was found to be clean, but needed lubrication. The motor was lubricated and a subsequent test of the four motors with the test pushbuttons was satisfactory. The engine was run again with the B train motors and it started satisfactorily.

The licensee performed other inspections and tests. The B side lubricating bottle oiler which supplies lubricating oil to the B air start motors was found to be defective and was replaced. No other defective EDG oilers were found. Preliminary investigation revealed that the apparent cause of this diesel failure was insufficient

oil to the B air start motors due to the defective oiler. The licensee is still investigating this failure and is in the process of instituting corrective actions. One corrective action is that all six EDGs, three per unit, will be run each week until the end of the first quarter of 1998. This decision was made to ensure EDG reliability since the 2A EDG also failed to start during a surveillance run in October, 1997.

c. Conclusions

The licensee met all technical specification requirements for the 2B emergency diesel generator (EDG) failure. Appropriate trouble-shooting activities were performed using an approved system engineering action plan. The apparent cause of the 2B EDG failure was a defective oiler resulting in insufficient lubrication to the B train air start motors. At the end of the report period, the licensee was continuing its investigation of the failure mechanism.

M8 Miscellaneous Maintenance Issues

M8.1 (Closed) NRC Technical Restart Issue II.41.1: Steam Generator Replacement Project (Unit 1)

This restart issue was last updated in IR 97-19. The issue remained open at that time pending additional review by the NRC Office of Nuclear Reactor Regulation (NRR) of the 10CFR 50.59 safety evaluations associated with the accident analysis. Subsequently, the NRC staff completed its review of the licensee's safety and transient analyses that supported its amendment to the facility Technical Specifications for Margin Recovery. This Technical Specification amendment was issued on December 18, 1997, and became the revised licensing basis and supported the licensee's steam generator replacement 10 CFR 50.59 safety evaluation. On the basis of the NRR staff's review of the Margin Recovery amendment and the fact that the replacement steam generators are similar to the original steam generators, the NRR staff has determined that no additional audit of the licensee's 10 CFR 50.59 safety evaluation is necessary. Therefore, Restart Issue II.41.1 for Unit 1 is closed.

M8.2 (Closed) NRC Programmatic Restart Issue III.a.4.2: Maintenance Department Backlogs (Unit 1)

a. Inspection Scope

Prior to the shutdown of both Salem units, a sizable corrective maintenance (CM) backlog contributed to long standing equipment problems and degraded material conditions. At the time of this inspection, approximately 2700 items remained in the Unit 2 corrective maintenance backlog, and 2600 items are estimated to be in the Unit 1 backlog following completion of the refueling outage. PSE&G developed a formal plan to reduce this backlog.

The inspector reviewed the CM backlog reduction plan and held discussions with Salem maintenance, planning, and system engineering personnel on the work

control process and the implementation of the backlog reduction plan. This issue was previously reviewed by the NRC in IR 96-18.

b. Observations and Findings

The goal of the backlog reduction plan is to reduce the CM backlog to 400 work orders. The licensee expects to reach this goal in two fuel cycles for each unit. Based on the Unit 1 restart schedule and resource availability, the maintenance department plans to reduce the CM backlog to 1000 work orders by the beginning of each unit's next refueling outage.

For each plant system, all outstanding CM work orders were reviewed by the responsible system manager and senior reactor operator (SRO), and separated in to "restart required" and "post restart" categories. This process was reviewed by the system readiness review board (SRRB). The inspector reviewed the "post restart" backlog items for the Unit 1 residual heat removal and auxiliary feed water systems, and noted that all items were properly categorized.

Salem maintenance has initiated an effort to categorize items in the CM and minor maintenance backlogs and group similar items together under common work orders. The Salem planning department has established measures for monitoring the progress of the backlog reduction effort, and performance indicators, such as completed work orders and new work orders, are trended on a weekly basis.

c. Conclusions

A sizable corrective maintenance backlog exists for both Salem units. A backlog reduction plan has been developed with achievable goals that can be attained without impact on plant safety and maintenance resources. Additionally, the licensee has established an adequate program for monitoring the effectiveness of the backlog reduction plan. The inspector concluded that the Salem staff adequately addressed the corrective maintenance backlog. This restart issue is closed.

III. Engineering

E1 Conduct of Engineering (37550, 37551, 40500, 92903, 93702)

E1.1 Update of 22 Steam Generator Steam Flow Transmitter Failure

a. Inspection Scope

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

b. Observations and Findings

During this report period, the licensee suspected that the cause of these channels drifting high was the removal or degradation of the low side sensing line insulation, which caused condensation formation in the line which was greater than the capacity of the installed drain. This reduces pressure on the low side of the flow transmitter and results in an erroneously high steam flow signal.

To verify this assumption, the licensee used a troubleshooting procedure to remove the insulation from the sensing line of the 23 SG steam flow channel II. With the insulation removed and the sensing line shielded from the main steam line, 23 SG channel II drifted high, giving indication that insulation removal was the root cause of the 22 SG transmitter failure. Subsequently however, the 22 SG channel II drifted high on two separate downpower events, after it had been indicating the correct steam flow for approximately two months with Unit 2 at 100% power. In both cases the indicated steam flow drifted up to about 80%, when actual power was about 26%. The indication returned to normal when power was raised above 30%.

The licensee now believes that a welded sleeve in the low side sensing line, where it taps off the main steam line, may be displaced. There is indication of this on some radiography which was performed on the steam line. This displaced sleeve could result in excessive condensate formation in the sensing line or even blockage of the drain hole which is designed to drain any condensation back to the main steam line. The licensee plans to replace the low side sensing line during the next Unit 2 forced outage and inspect the old line, once removed, to determine if it was the root cause. The channel II bistable will remain tripped, with forced values input to the digital feed system, until this maintenance is performed.

The inspector observed the Station Operations Review Committee (SORC) presentation and shift briefing for the 23 SG insulation removal, as well as control room activities before the removal, and the actual removal inside the Unit 2 containment. He concluded that these were well-planned evolutions with good coordination between operations, engineering, maintenance, and radiation protection personnel.

c. Conclusions

The licensee's removal of insulation from the 23 steam generator (SG) sensing line was a well-planned and coordinated evolution, but was not successful in determining the root cause of the 22 SG transmitter failure. However, the 22 SG high steam flow indications are now only present when power is reduced below about 30%. The channel II bistable remains in a tripped condition in accordance with Technical Specifications, with forced values input to the digital feedwater system. This challenges the operators in that they would need to take manual feed control of the 22 SG during a plant transient.

E2 Engineering Support of Facilities and Equipment

E2.1 (Closed) NRC Technical Restart Issue II.2: Control Air System Reliability (Unit 1) and Inspector Followup Item (IFI) 50-272 & 311/97-08-02

a. Inspection Scope

The inspector reviewed the Control Air System Reliability closure package, related Performance Improvement Requests (PIRs), work documentation, and design change packages (DCPs); and walked down portions of the control air system with the system manager. Additionally, the inspector observed random containment penetrations which are cooled by the Penetration Cooling (PC) system and checked the outlet temperatures of the Unit 2 main steamline penetrations to verify that PC was adequate to maintain concrete temperature less than 150 degrees, as required by the FSAR.

b. Observations and Findings

The inspector reviewed calculation number S-C-PC-MDC-1657, "Penetration Cooling Needle Valves Adjustment," Revision 3, which documented the justification for the positioning of PC needle valves to allow adequate PC for both Salem units, and maintain the station air system within the capacity of one station air compressor (SAC). This calculation showed that the minimum total PC flow demand per unit was 652/653 SCFM for Unit 1 and 2 respectively. The actual PC air flow measured from Unit 2 after unit startup was 1094 scfm. Although system demand could still be met with one SAC with this flow, the inspector questioned why this flow was much higher than that which was required. The balance of plant supervisor for system engineering stated that he was aware of this situation and that it would be addressed after Unit 1 restart. The inspector verified that PC flow was sufficient to maintain penetration concrete temperatures less than 150 degrees by checking that the PC air outlet for the main steam penetrations were well below that temperature.

The licensee replaced the Unit 1 PC air regulators with a new model and added strainers upstream of the regulators to prevent fouling. The Unit 2 regulators are scheduled for replacement in mid 1998. Additionally, a five-year recurring task was created to calibrate the pressure gages downstream of the regulators, to ensure that they maintain the correct pressure. Maplewood labs will measure Unit 1 PC flow for adequacy after unit startup. The licensee will monitor PC outlet temperatures to ensure that concrete is maintained less than 150 degrees.

The licensee completed DCP 1EC-3651 (SAC upgrade) on SAC no. 2, completed the DCP work but not retests on SAC no. 1, and has scheduled the work on no. 3 SAC for the first quarter of 1998. This DCP installs multiple SAC improvements to improve station air system reliability as previously discussed in NRC IR 96-17. The inspector considered this DCP to be an enhancement to the station air system.

c. Conclusions

The licensee made significant improvements to the station air compressors (SACs) to improve their reliability. The licensee also performed a detailed calculation to show the penetration cooling air flow necessary to maintain concrete temperatures within proper limits, and stay within the capacity of one SAC. The control air system was assessed as ready to support Unit 1 restart. Therefore, this Restart Issue II.2 and IFI 97-08-02 are closed.

E2.2 (Closed) NRC Technical Restart Issue II.4: Digital Feedwater Installation to Correct Feedwater Control Reliability (Unit 1)

a. Inspection Scope

Restart Issue II.4 concerned the use of a digital feedwater system to correct steam generator feedwater control reliability problems and problems pertaining to the steam generator atmospheric steam relief (MS10) valves. The NRC reviewed the licensee's resolution of this issue previously, as documented in NRC IRs 96-06 and 97-06. In this latter report (97-06), the NRC concluded that the digital feedwater control system modifications, including the addition of a new advanced digital feedwater control system, digital governor, new runback logic, and modified governor actuator should resolve the equipment reliability problems described above. Therefore, the restart issue was closed for Unit 2.

During the current inspection, the NRC reviewed the status of the Unit 1 modifications and the extent to which these modifications incorporated lessons learned from the Unit 2 modifications.

b. Observations and Findings

The inspector's review of the Unit 1 closure package and discussions with responsible engineering personnel determined that all modifications previously installed in Unit 2 had also been implemented in Unit 1. At the time of the package review, installation of all modifications (1EC-3206, 1EC-3345, and 1EE-0125) had been completed and testing was ongoing. Review of the modification packages also determined that the design change packages had been revised to incorporate lessons learned from the installation and testing of the Unit 2 modifications. These lessons learned included a variety of modification change requests (MCRs). The majority of the MCRs related to documentation discrepancies that were identified during the installation phase of the modifications. The MCR list also included several software changes that were properly implemented. No areas of concern were identified by the inspector during his review of the modification packages and MCRs.

c. Conclusions

The inspector concluded PSE&G had acceptably addressed the feedwater control reliability and MS10 valve concerns. The inspector also concluded that, although

testing of the installed modifications was still ongoing, confidence for positive results could be drawn from the successful testing of the Unit 2 modifications. Restart Issue II.4 is closed for Unit 1.

E2.3 (Closed) NRC Technical Restart Issue II.7: Emergency Diesel Generator has Minimal Load Margin (Unit 1)

a. Inspection Scope

The NRC reviewed the emergency diesel generator (EDG) loading as part of the Electrical Distribution System Functional Inspection (EDSFI) in 1993 (IR 93-82). At that time, the NRC inspector noted that the loading of EDG 2A was just below the 2-hour rating of the machine. As a result of this observation, PSE&G reevaluated the EDG loading and documented the results in calculation ES-9.002(Q), "Diesel Generator Loading," dated October 14, 1994.

The NRC originally reviewed the results of the calculation in February 1996, as documented in IR 96-01. Subsequently, based on the acceptable resolution of previous observations and verification of loads and load profiles, they concluded in IR 97-10 that the current EDG loading supported closure of the issue for Unit 2. The scope of the current review was to evaluate the current loading of the Unit 1 EDGs to ensure that sufficient margin existed to support Unit 1 restart.

b. Observations and Findings

As in the case of Unit 2, the Unit 1 closure package tabulated the available margins for all three Unit 1 EDGs and for the different EDG unavailability cases. Based on the data provided, the inspector determined that the margins available for the continuous and the 2000-hour ratings of the EDGs were calculated using the long-term loading, i.e., the loading expected at the completion of the automatic load changes (7200 seconds in most cases). The margins for the two-hour rating were determined at the highest loading. The tabulation showed that the minimum margin at the two-hour rating was 62 kW (Case C for EDG 1B). The tabulation also showed that, for 6 of the 9 case studies, the diesel generator would operate in the two-hour rating for 8 to 76 minutes.

The inspector compared the interim results of the nine case studies with the frequency derated ratings of the diesel generators and reviewed the load list. In particular he noted that the licensee had corrected the loading totals to account for battery charger current limit operation during the first two minutes. The inspector also confirmed the licensee's intent to revise the calculation of record post-restart. This revision was originally scheduled for December 1997, but postponed to support the Unit 1 restart activities.

c. Conclusions

Based on his review of the data presented in the closure package and discussions with responsible engineering personnel, the inspector concluded that a small, but

sufficient margin existed in the near term for the Unit 1 diesel generators. Therefore, Restart Issue II.7 is closed for Unit 1.

E2.4 (Closed) NRC Restart Issue II.8: EDSFI Followup (Unit 1)

a. Inspection Scope

In August 1993, the NRC conducted a functional inspection of the Salem electrical distribution system to evaluate its capability to perform its safety functions. The results of this inspection were documented in IR 93-82. The actions to address most of the identified issues were evaluated previously by the NRC and closed, as stated in IR 97-08. One item remained, involving verification that the Unit 1 safety-related molded-case circuit breakers had been properly tested. The purpose of this inspection was to ensure completion of this effort.

b. Observations and Findings

The testing requirements for molded-case circuit breakers are specified in PSE&G testing procedure SC.MD-ST.ZZ-0004. As specified in IR 97-08, the NRC concluded that the licensee had developed an acceptable testing program. During the current inspection, the NRC reviewed the result of several randomly selected molded-case circuit breakers. In addition, the inspector verified that the testing requirements in the procedure accurately reflected those of Calculation ES-13.005. No concerns were identified during this review.

c. Conclusions

Based on the above review, the inspector concluded that the licensee had taken acceptable actions to address testing of molded case circuit breakers. Restart Issue II.8 is closed.

E2.5 (Closed) NRC Technical Restart Issue II.9: Exhaust Steam Pipe Erosion Control Program (Unit 1)

a. Inspection Scope

The purpose of this inspection was to review the repairs on two 26" diameter nozzles located inside the No. 11 and 13 low pressure (LP) turbine. This activity was left open in IR 96-10.

b. Observations and Findings

The inspector reviewed Root Cause Analysis Report S-C-BS-MEE-1054 and evaluated the status of the recommended repairs. Recommended repairs included the removal of all spring supports in the last stage extraction steam piping and the replacement of nozzles without gussets.

The inspector reviewed the nozzle repair procedure, DCP 1EC-3535, and the associated Modification Concern Resolutions, and found that they were complete and well organized. Additionally, the inspector reviewed the licensee's 10 CFR 50.59 Applicability Review, form NC.NA-AP.ZZ-0059-2, for this repair activity and found it to consistent with the work that had been performed.

c. Conclusions

The inspector concluded that the actions to address the cracked nozzle issues were acceptable and justified and that the changes should prevent recurrence of the cracking. Restart Issue II.9 is closed.

E2.6 (Closed) NRC Technical Restart Issue II.14: Hagan Module Replacement (Unit 1)

a. Inspection Scope

During the original review of the licensee's program to address Hagan module concerns as documented in NRC IR 96-06, the inspectors identified four issues requiring resolution by PSE&G:

1. Impact of calibration temperature on instrument loop accuracy calculation.

2. 10 CFR 50.59 evaluation of upgraded Hagan modules.

3. operating temperature of Hagan and NUS modules; and,

4. Impact of electromagnetic and radio frequency interference (EMI/RFI) on Hagan and NUS modules.

Resolution of these issues was reviewed by the NRC and found acceptable for Unit 2 restart. The purpose of this review was to evaluate potential programmatic differences between the two units.

b. Observations and Findings

The inspector's review of the Unit 1 Hagan module program implementation identified no substantial differences except as discussed below.

Availability of more NUS modules resulted in the licensee replacing three additional Hagan modules (Power Supplies, Comparators and Low Level Amplifiers) with NUS equivalent modules. The inspector reviewed the design of the NUS modules and confirmed that they met the design requirements previously established for the Hagan modules. In particular, the inspector addressed the NUS modules operating temperature and resistance to EMI/RFI. The inspector identified no concerns with the design and application of the modules.

Regarding safety evaluations of upgraded Hagan modules, IR 97-02 documented the preliminary revisions that had been made to station procedure NC.DE-WB.ZZ-

003(Q), "Engineering Workbook for Equivalent Replacement." The inspector confirmed that the procedure revisions had been formally implemented.

Additional Observations

In conjunction with this review, the inspector determined that the licensee had identified some instrument loops that were potentially overloaded. Discussions with the licensee determined that the overloading concerns were based on Westinghouse guidelines specifying that loop resistance should not exceed 1000 Ohms. These discussions also revealed that the instrument loop loading limitations had been established not because of power supply limitations, but to ensure that the transmitters received the minimum voltage for correct operation. The licensee's evaluations confirmed that, for the loops having resistance in excess of 1000 Ohms, the power supply provided sufficient voltage to the associated transmitters. In addition, for some loops, the licensee specified a slightly higher power supply output voltage. The inspector verified the bases for the licensee's conclusions and found them acceptable.

While reviewing the documentation associated with the instrument loop overload issue, the inspector also noted that the environmental qualification testing of the Rosemount transmitter assumed a maximum power dissipation by the transmitter of 0.36 Watts. Based on the power supply used, this limitation meant that the loop resistance should be at least 500 Watts. The inspector confirmed that the instrument loops had been verified to have a minimum resistance of 500 Ohms. Discussions with licensee engineering, however, determined that no guidelines existed to ensure that future instrument loop designs or loop changes would not invalidate the environmental qualification of the transmitters through under-loading. Although they believed that enough information existed to prevent the instrument loop designer from improperly loading the circuit, the licensee indicated that they would evaluate alternatives to assure that appropriate information was available to the instrument loop designer. This is an inspector followup item to evaluate the licensee's actions to ensure that adequate information will be available to the instrument loop designer for the proper revision and design of instrument loops in the future. **(IFI 50-272 & 311/97-21-03)**

c. Conclusions

The inspector concluded that PSE&G's program for the Hagan modules was also acceptable for Unit 1 restart. Restart Issue II.14 is closed.

E2.7 (Closed) NRC Technical Restart Issue II.16: IST Program Deficiencies (Unit 1) (See also Sections E7.1 and E7.2)

a. Inspection Scope

The inspector reviewed PSE&G's Inservice Test (IST) program documents, the Salem Updated Final Safety Analysis Report (UFSAR), technical specifications, system drawings, and surveillance test procedures to verify that pumps and valves

that perform a safety function were included in the IST program. The inspection focused on the Unit 1 residual heat removal system. The NRC reviewed the Unit 2 IST program and found it acceptable, as documented in IR 97-05.

b. Observations and Findings

The inspector found the IST program for the residual heat removal system to be complete and well documented. The safety function of each component was evaluated in program basis data sheets that referenced the applicable technical specification and UFSAR sections, and other design basis calculations and documents. Surveillance procedures met ASME Code requirements for test method, instrument accuracy, frequency, and acceptance criteria. The procedures also provided detailed instructions to operators when acceptance criteria were not met. The instructions were consistent with Code provisions. Cold shutdown justifications (for test deferral) were well documented.

c. Conclusions

The IST program for the Unit 1 residual heat removal system was implemented effectively and was acceptable for plant startup. Restart Issue II.16 is closed for Unit 1.

E2.8 (Closed) NRC Technical Restart Issue II.17: Main Condenser Steam Dumps Malfunction (Unit 1) and Inspector Followup Item (IFI) 50-311/96-18-04

a. Inspection Scope

The inspectors documented in NRC IR 96-18 that this issue was closed for Unit 2, with the exception of restart testing of the steam dumps. The inspector observed Unit 2 restart testing and reviewed the restart data with the Manager, System Engineering. He also reviewed the restart closure package for Unit 1 steam dump valves and performed a walkdown of the valves with the system engineer.

b. Observations and Findings

The licensee completed Design Change Package (DCP) 1EE-0117 on Unit 1 steam dump valves. This DCP included various valve upgrades such as new Bailey valve positioners and new stainless steel flexible metal hose connectors. It also incorporated lessons learned from DCP 2EE-0093 on the Unit 2 valves, including larger volume boosters for shorter valve stroke times. The Unit 1 valves will also be evaluated during restart testing. The inspector considered the DCP package to be a system enhancement.

The Unit 2 valves performed as designed during restart testing. The addition of volume boosters to the Masoneilan valves (TB10 and 20 valves) resulted in closure times less than or equal to five seconds, a significant improvement. Opening times were improved as well. Although the licensee does not take credit for these valves

in its accident analysis, their improved performance will enhance plant response to transients.

The licensee also implemented a revision to EOP-FRHS-1, "Response to Loss of Secondary Heat Sink." This procedure now makes provision for use of the steam dumps for steam generator depressurization when the main condenser is available. The inspector concluded that this Unit 1 revision completed corrective actions for an NRC-identified deficiency regarding technical adequacy of the Emergency Operating Procedures (EOPs).

c. Conclusions

The licensee completed a DCP which enhanced the Unit 1 steam dump valve performance and implemented related EOP changes to address the issue of EOP technical adequacy. The Unit 2 steam dump valves performed adequately during restart testing. The inspector concluded that licensee actions were comprehensive and sufficient to support Unit 1 restart. This restart issue and IFI 96-18-04 are closed.

E.2.9 (Closed) NRC Technical Restart Issue II.18: Poor Positive Displacement Pump (PDP) Reliability (Unit 1).

a. Inspection Scope

The Salem Unit 1 & 2 Positive Displacement Charging Pumps (PDPs) have had a history of maintenance and operating problems. In order to improve operational reliability, a root cause analysis was performed to identify the causes and to prescribe corrective actions for short and long term implementation. The analysis concluded that the failures resulted from numerous mechanisms including packing failures, pump valve cracking failures, pump valve seat cracks, PDP cylinder block cracking failures, and failure of the suction stabilizer. Resolution of this issue for Unit 2 was reviewed previously and found acceptable, as documented in IR 96-12. The scope of this inspection was to evaluate any differences between Unit 1 and Unit 2 and to verify proper resolution of this issue for Unit 1. In addition, the inspector reviewed the recent performance of the Unit 2 PDP to evaluate the effectiveness of the licensee's corrective actions.

b. Observations and Findings

The inspector reviewed the licensee's closure package for poor reliability of the Unit 1 and Unit 2 PDPs, which was updated to reflect the status of Salem Unit 1 PDP and accepted by the General Manager - Salem Operations on November 1, 1997. In addition, the inspector reviewed a sample of work orders and procedures for the Unit 1 PDP to verify implementation of corrective actions. Specifically, the inspector verified that work order (WO) 960422020, for inspection of the pump internals, and WO 951006064, for inspection of the suction stabilizer, were completed on November 4, 1997. Also the inspector verified that procedure S1.OP-PT.CVC-0001,

"13 Charging Pump Suction Stabilizer/Pulsation Dampener," was appropriately revised to include the correct suction stabilizer venting instructions.

The inspector discussed the condition of the Salem Unit 1 and Unit 2 PDPs with the Chemical and Volume Control System (CVCS) system manager and observed the physical condition of the PDPs through a field walkdown. In IR 96-12, the inspector had stated that the operating data for Unit 1 indicated that although one 3900 hour run was achieved between packing failures, two subsequent packing related problems indicated that the problem was not resolved. During this inspection, the system manager clarified that although the failures were documented as packing related, packing failure was not the root cause of the failures in the two subsequent cases. In addition, the subsequent runs were about 2000 hours each, which was an improvement over previous run times of 1200 - 1500 hours.

The inspector also noted that the Unit 2 PDP had been considered inoperable for the period November 10, 1997 through January 15, 1998. The system manager indicated that the pump failure on November 10 was related to a failed relief valve, and was not related to the pump packing. Part of the delay in returning the Unit 2 PDP to service, was attributed to inadequate initial understanding of conditions when the pump was taken out of service on November 10, and how the PDP maintenance activities were scheduled in the 12 week work schedule. The licensee intends to perform additional evaluation of the effectiveness of their root cause analysis and corrective actions by performing addition inspections of the Unit 2 PDP and performing a detailed examination of the Unit 2 PDP work orders and problem reports from July 1, 1996 through April 20, 1998 as documented in condition report (CR) 960113281.

c. Conclusions

The licensee has implemented appropriate corrective actions to address the longstanding reliability issues associated with the Unit 1 positive displacement charging pump. Restart Issue II.18 is closed for Unit 1.

E2.10 (Closed) NRC Technical Restart Issue II.19: Configuration Control Pipe Supports (Unit 1)

a. Inspection Scope

The scope of this inspection included a review of pipe stress analyses of as-built piping and pipe supports. Specifically, the inspector randomly selected two pipe stress calculation packages for detailed review: No. 267662, corresponding to the chemical and volume control system (CVCS), and No. 267172A, corresponding to the feedwater system. Further, the inspector walked down the piping and the supports of the two packages.

b. Observations and Findings

The resolution of a previous stress analysis documentation problem resulted in the generation of many discrepancies for both Salem Units 1 and 2, as documented in NRC IRs 95-06 and 97-08. These discrepancies were the result of unchecked calculations, modifications that were not carried out, unavailable calculations, incorrect thermal analyses, and unsupported engineering judgements. An evaluation of these discrepancies previously resulted in a non-cited violation.

The facility has since addressed the discrepancies for Salem Unit 1 and because of this effort, a total of 57 pipe support modifications in six safety-related piping systems were done. These modifications were in the CVCS, containment, containment spray, diesel oil, feedwater and main steam systems. The modifications generally consisted of adding structural members, higher capacity snubbers, straps, and base plate anchors.

The inspector reviewed the methodology used to perform stress calculations, in particular, the model representing the piping, the load combinations used in the analysis, the computer code, and the results of the analyses. The inspector found pipe stress calculations No. 267662 and 267172A complete and acceptable.

Within these two stress calculation packages, the pipe supports were either qualified in their present as-built configuration or they were modified to accommodate the results of the pipe stress analyses. The inspector reviewed the pipe support calculations of the modified pipe supports and found these calculations complete and acceptable. Further, the inspector walked down the piping and the supports of the two stress packages and determined that the as-built configuration was properly represented in the design documents.

During the field walkdown, the inspector observed that the pipe supports were well constructed and appeared to be structurally sound. The inspector also observed some corrosion at a snubber trunnion (No. MD H06 of feedwater system support No. S13FWSN15A & B). Subsequent to the onsite inspection, facility inservice inspection (ISI) personnel examined this support trunnion and found it to have no reduction in metal. They concluded that the support was in good condition. The inspector discussed the ISI examination with responsible personnel and judged their conclusions acceptable.

The inspector reviewed the facility's approach to assuring the quality of the pipe support modifications, and determined that it was acceptable. Post-modification walkdowns were performed in accordance with an approved procedure. The walkdown team consisted of members from the stress group, station system engineer and project installation group. The final acceptance of the package was evident in the quality control sign-off sheets testifying that the post-modification examinations were completed and properly documented.

c. Conclusions

The inspector concluded that the previously-identified pipe support concerns regarding six safety-related systems at Unit 1 had been properly resolved by a combination of reanalyses and modifications. Restart Issue II.19 is closed for Unit 1.

E2.11 (Closed) NRC Technical Restart Issue II.21: Wiring Separation and Redundancy Concerns with RG 1.97 Instruments and Cable Separation (Unit 1)

a. Inspection Scope

This item involve two issues, one pertaining to wiring separation and redundancy concerns with post-accident monitoring (RG 1.97) instruments and the other pertaining to cable separation in the plant. Both of these issues were reviewed previously. As documented in IR 97-02, the NRC reviewed and found acceptable the licensee's actions to address the RG 1.97 separation and redundancy issues. Regarding cable separation in the plant, as documented in IR 97-08, the NRC review of PSE&G's revised program and correction of the Unit 2 identified deviations concluded that they had acceptably addressed the separation issues originally identified by the integrated performance assessment team (IPAT) inspection. The NRC further concluded that the actions taken to correct the Unit 2 identified deviations were appropriate. The purpose of this inspection was to ensure that the separation program outlined for Unit 2 was also implemented for Unit 1 and that the Unit 1 deviations had been properly corrected.

b. Observations and Findings

The inspector's review of the separation program confirmed that the criteria delineated for Unit 2 were also implemented in Unit 1. The inspector also conducted walkdowns of several plant areas, including containment. He determined that the separation deviations identified by the licensee had been acceptably corrected by wrapping the cables with fire retardant materials. Two apparent uncorrected deviations observed by the inspector were acceptably justified by the licensee.

c. Conclusions

The inspector concluded that the licensee had acceptably addressed the IPAT-identified separation issues at Unit 1 and that deviations were acceptably corrected to conform to the revised criteria. Restart Issue II.21 is closed for Unit 1.

E2.12 (Closed) NRC Technical Restart Issue II.22: Power Operated Relief Valve (PORV) Seat Leakage (Unit 1)

a. Inspection Scope

This purpose of this restart inspection was to evaluate the actions taken by PSE&G to resolve PORV seat leakage problems that occurred after an inadvertent safety injection in April 1994. Aspects of this issue that relate to the reliability of the control air system were inspected under restart item II.2. The licensee's actions to address this problem for Salem Unit 2 were previously reviewed and closed in NRC IR 96-12.

b. Observations and Findings

In April 1994, a Salem Unit 1 plant transient resulted in multiple cycling of the primary PORVs. Subsequent to the transient, PSE&G performed inspections of the valve internals and found that the internals exhibited unexpected cracking, galling, and wear. As a result, PSE&G contracted with MPR Associates, Inc. (MPR) to perform a root cause evaluation to explain these observations. In their root cause report (MPR-1494, dated June 1994), MPR noted that factors, such as, differential thermal expansion, stem/plug torque and preload, actuator force, tight dimensional tolerances, and plug boss design contributed to the noted observations. These factors could be addressed by optimizing the selection of the materials used for the PORV internals. PSE&G contracted with Wyle laboratories to perform full pressure cyclic testing of four different combinations (trim sets) of PORV internal materials to determine the optimum material. Each material combination was subjected to a minimum of 2000 cycles of operation and then disassembled for inspection. After this testing, an optimum material combination was selected which included a 420 Stainless Steel (SS) plug, 316 SS stem with chrome plating, and a 420 SS cage, along with a 300 series SS roll plug pin and a 304 SS cage spacer. In addition, the boss will be redesigned to eliminate crack induced zones and the backseat will be eliminated. This trim set exhibited superior endurance results during the Wyle testing.

Design Change Package (DCP) 1EE-0104 was developed to replace the existing PORV internals with trim sets using these optimized materials. These new trim sets were installed in both PORVs (1PR1 and 1PR2) on November 21, 1997. These trim sets are awaiting final retest after the plant is fully pressurized.

The design basis of the PORVs was recently revised by The Salem Unit 1 Evaluation of the Pressurizer PORVs for an Inadvertent Safety Injection (SI), S-1-RC-MEE-272, Rev. 0, dated December 10, 1997, to require each PORV to provide a minimum of 110 cycles to cope with an Inadvertent SI. Since the Wyle testing required satisfactory performance after 2000 cycles, the new trim set exceeds the cyclic requirements contained in the design basis for an Inadvertent SI.

c. Conclusions

The inspector noted that the testing done at Wyle Labs cycled the PORV trim sets of various materials in excess of 2000 cycles. As a result of this testing, an optimum material combination was selected. The design basis of the PORVs requires each PORV to provide a minimum of 110 cycles to cope with an Inadvertent SI. Since the new PORV trim sets have been tested greatly in excess of their cyclic design requirements with no significant leakage, there is reasonable assurance that the previous leakage problems have been corrected. Based on the above, this restart item is closed.

E2.13 (Closed) NRC Technical Restart Issue II.23: Undersized Power Operated Relief Valve (PORV) Accumulators (Unit 1)

a. Inspection Scope

The inspector reviewed PSE&G's actions related to undersized PORV accumulator for Salem Unit 1. This review included discussion with PSE&G personnel, independent review of test results, and inspection of the Salem Unit 1 restart item closure package for this issue. A similar item was reviewed prior to Salem Unit 2 restart in NRC IRs 96-18 and 97-08. The lessons learned from the Salem Unit 2 review were incorporated in actions taken to address this issue for Salem Unit 1.

b. Observations and Findings

On December 17, 1997, the licensee completed their final review and sign-off of the Salem Unit 1 restart item closure package for the undersized PORV accumulators. This issue was raised because in the original Inadvertent Safety Injection (SI) Initiation (Condition II Event) analysis, the licensee assumed operators would act to terminate the event prior to the pressurizer completely filling with water. As a result of reanalysis, and since PSE&G had not qualified the code safety valves to operate with water flow, the licensee determined that the pressurizer PORVs would have to actuate automatically to control RCS pressure. A stuck open code safety valve resulting from water flowing through it would result in a small break loss of coolant accident (LOCA), a Condition III event. One design requirement for a Condition II event is that it should not propagate into or cause a more serious fault (e.g., a Condition III event). Thus, to cope with this event, PSE&G had to qualify the PORVs for safety related operation.

In the Salem Unit 1 design, there are two PORVs each with a motor operated block valves. Normally, both block valves are open and both PORVs are closed. When a high pressure condition exists the PORVs can be opened either manually or automatically. Previously, Technical Specification (TS) 3.4.3 allowed either or both PORVs to be inoperable as long as the associated block valve was closed. However, this TS became inconsistent with the new requirements for the PORVs in coping with an Inadvertent SI Initiation Event. Thus, the licensee processed a TS change to require both PORVs to be operable in Modes 1, 2, and 3. Additionally, since the PORVs had no previous requirement for accident mitigation, PSE&G had to

initiate action to upgrade the control circuitry to safety related status, including meeting single failure criteria. The licensee had completed this upgrade per Design Change 1EC-3696, and concurrently processed a TS amendment requiring that both PORVs be operable during hot conditions. Thus, both the physical hardware and the TS were upgraded to cope with an Inadvertent SI Initiation Event.

Another important consideration is the ability of the PORV accumulators to provide for PORV operation throughout the duration of the design basis event. The Salem Unit 1 Evaluation of the Pressurizer PORVs for an Inadvertent Safety Injection, S-1-RC-MEE-272, Rev. 0, dated December 10, 1997, describes this event in detail. Section 4.6 summarizes the event, and notes that up to 220 strokes of the PORVs may be needed to cope with this event under worst case conditions. Thus, it is imperative that the leakage of control air used to stroke the PORVs be limited. To consider this, a review of the basic design is appropriate. For the Salem Unit 1 design, there are two air accumulators per PORV that were installed to backup the normal supply from the control air system. There are two check valves for each set of PORV accumulators and they are located in control air system supply lines. If control air is lost, the check valves act to limit pressure decay in the system, thus assuring PORV operation. Thus, it is appropriate to limit leakage through these check valves.

To assess the impact of existing system leakage, the inspector reviewed the results from the most recent leakage tests performed on December 16 and December 18 per SC.RA-IS.PZR-0024(Q), Revision 4, "Leakage Test of PORV Accumulators." These tests required the establishment of two different sets of conditions, one which simulates a slow loss of air, and the other which simulates a sudden loss of air. An administrative limit of 147 sccm is provided for both tests. All four interfacing system check valves (1CA1768, 1CA1769, 1CA1770, 1CA1771) were tested and the worst case leakage was 110 sccm which was well within the 147 sccm administrative limit. This limit was also used as an assumption for the Salem Unit 1 Evaluation of the Pressurizer PORVs for an Inadvertent Safety Injection, S-1-RC-MEE-272. Thus, the inspector verified that the leakage limits for the PORV accumulators were acceptable and met design requirements.

c. Conclusions

The inspector noted that PSE&G installed a design change to upgrade the PORV control circuitry to safety related status, including meeting single failure criteria. Additionally, Technical Specification 3.4.3 was changed to require both PORVs to be operable in Modes 1, 2, and 3 which was needed to cope with an inadvertent safety injection initiation event. The inspector also confirmed that leakage through the PORV accumulator check valves was acceptably low providing additional assurance that the PORVs can fulfill their accident mitigation function for the duration of the event. Thus, based on the above, there is reasonable assurance that the current design, operation, and testing of the PORVs and their associated accumulators is adequate to ensure the ability of Salem Unit 1 to cope with an Inadvertent Safety Injection Initiation Event. Therefore, this restart item is closed.

E2.14 (Closed) NRC Restart Issue II.24: Gate Valves Identified Susceptible to Pressure Lock and Thermal Binding (Unit 1)

a. Inspection Scope

Concerns regarding pressure locking/thermal binding of gate valves were originally identified by the NRC in IR 93-26. Resolution of this concern was reviewed previously, as documented in IRs 96-07 and 96-20. In the latter report, some issues were left open pending licensee corrective actions. The purpose of this inspection was to evaluate the licensee's resolutions of the outstanding issues.

b. Observations and Findings

1PR6 and 1PR7 Motor Operator Valve (MOV) Assembly Modifications

To address this issue, the inspector confirmed that the installation and testing of the 1PR6 and 1PR7 modifications had been completed. He identified no discrepancies during his review of the design change package. He also determined that the motor operated valve baseline testing for the Valve Operation Test and Evaluation System (VOTES) had been completed. During his review of Work Order (W/O) 970313177 ACT 04 and 05, the inspector found that the maximum allowable thrust reading had been incorrectly recorded on Attachments 18 and 19 of the VOTES Data Acquisition for Motor Operated Valves procedure SC.MD-EU.ZZ-0012 (Q). To evaluate whether the discrepancies identified constituted an isolated case, the inspector reviewed additional work orders performed with the procedure. He found similar errors in most of the work orders reviewed. Examples of identified discrepancies follow.

1. The maximum allowable thrust reading calculation for valves 1PR6, 2PR6, and 12CC16 (W/Os 970424106, Act 5; 960619026, Act 4; and 971013153, Act 2, respectively) used incorrect values for Thrust Switch Repeatability on Attachment 15 of test procedure SC.MD-EU.ZZ-0012 (Q). Also, for valve 2PR6, the system accuracy calculation used an incorrect value for torque correction factor.

2. On Attachments 18 and 19 of the test procedure for valves 1PR6 and 1PR7 (W/O 970424128, Act 5), the maximum allowable thrust reading was recorded incorrectly.

3. On Attachment 19 of procedure SC.MD-EU.ZZ-0012 (Q) (W/O 971013153, Act 2), the maximum thrust (Closed) for valve 12CC16, as originally evaluated, was slightly greater than the maximum allowable thrust. This condition had not been flagged in the comments section of the procedure.

The inspector also noticed that when the errors in paragraph 1, above, are discounted, the results of the calculation for maximum allowable thrust reading were a few pounds off. Neither these errors or the errors described above impacted in any way the conclusion of the test because the

calculation errors amounted to only a few pounds and, in most cases, the measured values were well below the calculated allowable values. Even in the case of valve 12CC16 (paragraph 3), the difference between the two values was only 27 (out of 23754) pounds. However, the errors on Attachment 18 and 19 (paragraph 2) could have impacted the conclusion, because the difference between the calculated value and the value used on Attachments 18 and 19 was approximately 1500 pounds.

10 CFR 50, Appendix B, Criterion XI requires test results to be documented and evaluated to assure that the test requirements have been satisfied. Failure to identify and correct these deficiencies could result in the inability of a safety-related valve to accomplish its safety-related function and is a violation of this requirement. **(VIO 50-272&311/97-21-04)**

PR6 and PR7 Stroke Time Testing

The inspector reviewed S2.OP-ST.PZR-0002(Q) (W/O 95090121-01 and 96052202-06) and found that the stroke time testing of 2PR6 and 2PR7 for Unit 2 had been completed. Stroke time testing for 1PR6 and 1PR7 has been scheduled, but not completed at the time of the inspection.

11CS2 and 12CS2 Surveillance Procedure Revisions

The inspector found that the applicable procedures had been revised to incorporate steps to prevent pressure locking and thermal binding. No concerns were identified with these procedures.

c. Conclusions

The licensee generally took proper corrective actions to address the susceptibility of gate valves to pressure locking and thermal binding. Therefore, Restart Issue II.24 is closed for Unit 1. No concerns were identified with the modifications and stroke time testing of the valves within the scope of the review. However, less than acceptable review of the VOTES test results was identified as a violation.

E2.15 (Closed) NRC Technical Restart Issue II.26: Radiation Monitor Problems (Unit 1)

a. Inspection Scope

In 1994, the NRC expressed a concern regarding the quantity of corrective maintenance required by the radiation monitoring system (RMS) and the undue burden of this on the operators and maintenance staff of both Salem units. The NRC reviewed the licensee's corrective actions to resolve the various Unit 2 RMS issues previously. As documented in IR 97-05, for Unit 2, the inspector concluded that the licensee had made considerable progress in improving the reliability of the RMS and that the system was acceptable for the restart of Unit 2. The purpose of this inspection was to review the scope and status of the Unit 1 system enhancements.

b. Observations and Findings

As stated in the closure package for the subject issue, PSE&G agreed that the maintenance activities were a concern due to the distraction posed to the operation and maintenance staff. To address this concern, they reviewed all maintenance activities performed on the RMS between 1991 and 1996. They found that the Unit 2 monitors had experienced many more failures than those of Unit 1 and that for Unit 1, as for Unit 2, most failures involved only a few channels. Based on the results of their investigation, they developed a plan to resolve the system maladies.

The inspector's review of the activities scheduled to be completed prior to Unit 1 restart found that a large portion of the work was still ongoing. The work involved corrective and preventive maintenance as well as installation of modifications that had been designed to correct identified problems. By the end of the inspection, the licensee had installed all DCPs required for Mode 4 operation and had made substantial progress in reducing the maintenance activities. Of the planned work, only the DCPs associated with radiation monitors R46 had been postponed.

Main steam line radiation monitors 1RM46A through E experienced repeated short circuits. The problems were the result of excessive condensation, during high humidity days, and the required cooling. To resolve this issue the licensee initiated two DCPs, 1EE-0138 and 1EE-0185. These changes, involving the installation of hermetically sealed detectors and anti-sweat insulation, were effectively implemented for Unit 2 and were scheduled to be implemented for Unit 1, prior to restart. Apparently, the required detectors were lost and new detectors could not be secured prior to restart. Therefore, the changes were postponed until March or April 1998. Because condensation due to high humidity is mostly a summer time concern, the inspector considered the postponement acceptable. Regarding the loss of the detectors, the inspector determined that they contained low activity sources (below the reportability level) and were not a safety concern.

A review of PSE&G's actions to address past RMS deficiencies concluded that the resolution was reasonable. In addition, a review of selected safety evaluations for the DCPs developed identified no safety concerns. Lastly, the inspector discussed with licensee engineering the success of modifications performed on Unit 2 monitors. He determined that the performance of the Unit 2 system had been well above the targeted 85% availability.

As in the case of the Unit 2 RMS, the inspector determined that the licensee had included the Unit 1 RMS in the Maintenance Rule scope and had similarly established goals regarding system availability, failure rates, and RMS-related LERs.

c. Conclusions

The inspector concluded that the licensee has taken appropriate steps to improve the performance of the Unit 1 RMS. Where design was deficient, the licensee had implemented modifications to rectify the deficiencies. Although not all work was completed, most of the work pertained to components required to support Mode 2

operation, and the activities were scheduled and ongoing. Therefore, Restart Issue II.26 is closed.

E2.16 (Closed) NRC Technical Restart Issue II.33: Control Rod Stepping with No Temperature Error Signal (Unit 1)

a. Inspection Scope

NRC IR 94-19 described observations by the Salem Unit 2 operators regarding intermittent control rod movement without operator intervention. The licensee's review of this issue determined that the control rod stepping was due to process noise from the nuclear instrumentation. PSE&G's resolution of this issue for Unit 2 involved the installation of a design modification involving a revision of the Tavg lead/lag and filter time constants and of the error signal at the breakpoint of the nonlinear gain in the power mismatch channel. The Unit 2 modification was reviewed previously and found acceptable, as documented in IRs 96-10 and 97-08. The purpose of the current review was to evaluate the results of the Unit 2 modification and verify the implementation of the same design modifications for Unit 1.

b. Observations and Findings

The Unit 1 design modifications were detailed in design change package (DCP) 1EC-3323. The inspector's review of the status of these modifications confirmed that they had been implemented. At the time of the review, however, functional testing had not been completed.

To verify the effectiveness of the Unit 2 modifications the licensee intended to conduct a special test. This test, which entails the monitoring of the output signal of the modified rod control modules and compare it to that of the unmodified modules, was rescheduled several times and, at the completion of the inspection, had not been performed. However, discussions with plant operators and a review of plant records determined that spurious control rods stepping had occurred only twice, once in each direction, in approximately five months.

c. Conclusions

Although a confirmatory test of the effectiveness of the Unit 2 modifications had not been completed, based on the very small quantity of rod movements experienced by the operating staff, this restart issue is also closed for Unit 1. The NRC will review the results of the functional tests of the modified control modules during their review of the Unit 1 test program addressed by item III.a.22 of the restart plan.

E2.17 (Closed) NRC Technical Restart Issue II.34: Numerous Safety Injection Pump Deficiencies (Unit 1)

a. Inspection Scope

The inspector reviewed the closure package for restart issue II.34, which included the licensee's closure basis, and 11 and 12 safety injection (SI) pump in-service test data. The inspector also reviewed restart required work orders for the SI pumps. This issue was previously reviewed by the NRC in IRs 96-08 & 96-18, for Unit 2.

b. Observations and Findings

The corrective actions taken for Unit 1 were identical to those of Unit 2, with the addition of relocating a heating steam trap above 11 SI pump to prevent leakage onto the pump. The licensee demonstrated adequate pump performance through surveillance tests including pump curve testing and system flow balancing.

The inspector noted that 34 minor work items remained open. Many of the open work orders were post maintenance test items that require the plant to be in Mode 4 or 3. The inspector did not identify any items that would challenge SI pump performance and reliability, or prevent safe plant entry to Mode 4.

c. Conclusions

The corrective actions taken to correct Unit 1 safety injection pump deficiencies were effective. The licensee adequately demonstrated satisfactory safety injection pump performance. Restart issue II.34 is closed for Unit 1.

E2.18 (Closed) NRC Technical Restart Issue II.35: Verify Adequate Protection for Safety Injection Pump Runout (Unit 1)

a. Inspection Scope

Throttle valves SJ16, SJ143, and SJ138 provide Charging and Safety Injection (SI) pump runout protection. During certain accident conditions, a high pressure drop may exist across these valves, and the valves may experience cavitation and erosion. As a result, the valves may not restrict Charging and SI pump flows below their runout limits, and the pumps may not operate to provide long term core cooling. The licensee also determined that during the recirculation phase of a postulated accident, these throttle valves may not be opened sufficiently to prevent flow blockages from debris. This issue was reviewed previously by the NRC in IR 96-10 & 96-20.

The inspector reviewed the closure package for restart issue II.35, and design change package (DCP) 1EC-3530, "Cavitation Mitigation on Safety Injection Cold and Hot Legs."

b. Observations and Findings

DCP 1EC-3530 installed flow resistance orifices in the charging and intermediate head SI discharge piping to the cold and hot legs. These orifices produce the required pressure drop and allow the SJ16, SJ143, and SJ138 valves to be opened more, such that design flow rates are achieved without cavitation and SI pump runout damage.

The inspector performed a walkdown of the field work for DCP 1EC-3530. All flow orifices were found to be installed in the correct locations. Through review of post modification testing, the inspector noted that the cold leg throttle valves and one hot leg throttle valve did not meet their open acceptance criteria. Unlike Unit 2 post modification testing, the licensee did not perform acoustic monitoring to verify that no cavitation existed at the throttle valves or the orifice assemblies during charging and SI pump operation. Instead, an evaluation of the test data was performed by the architect engineer, Duke Engineering and Services. The evaluation determined that the as-left positions of the throttle valves are acceptable and no cavitation exists. Additionally, the as-left positions of the throttle valves were sufficiently open to prevent debris blockages.

c. Conclusions

The installation of the flow resistance orifices was effective in mitigating cavitation in the cold and hot leg injection lines, and providing pump runout protection for the charging and safety injection pumps. DCP 1EC-3530 had been properly implemented and the post modification testing was adequate. Restart issue II.35 is closed for Unit 1.

E2.19 (Closed) NRC Technical Restart Issue II.40: Verify Adequate Correction for Overhead Annunciator Failures (Unit 1)

a. Inspection Scope

This item was opened to track the licensee's followup and resolution of overhead annunciator (OHA) design concerns that were raised following annunciator failures in 1992, 1995, and 1996. The annunciator design and PSE&G's resolution of the identified design weaknesses for Unit 2 were reviewed in September 1996, as documented in IR 96-13. At that time, the inspector concluded that PSE&G had taken sufficient steps to correct the known Unit 2 OHA system failures. The inspector also concluded that, although future OHA system failures could not be precluded, the system design modifications and procedural changes implemented by PSE&G provided sufficient assurance that such failures would be detected and resolved in a timely manner.

The purpose of this inspection was to review the licensee's evaluation and resolution of OHA failures since September 1996, and to verify implementation of equivalent design modifications and procedural changes for Unit 1.

b. Observations and Findings

The inspector's review of OHA failures since September 1996 determined that the licensee had issued four Performance Improvement Requests (PIRs), as described below, to document system anomalies identified during the same period.

- PIR 961004139 described the loss of OHA window boxes for 15 seconds during the transfer of the OHA from the primary to the backup sequential event recorder (SER) to install a database change. The failure was the result of firmware coding errors in the Hathaway Model 4100R SER and Model 1500 distributed annunciator controller. This event had minor safety significance and, at no point, were the CRT or printer affected by the anomaly. The licensee replaced the Unit 1 firmware with upgraded versions of the same and planned to replace the Unit 2 firmware during the next refueling outage. The new firmware had undergone vendor validation and verification.

- PIR 961206279 documented an event involving flash photography that caused loss of configuration in a microprocessor and an OHA trouble alarm. Only one alarm window was involved. The licensee determined that the system is susceptible to electro-magnetic and radio-frequency interference (EMI/RFI). The system is installed in a radio-free zone and flash photography is now prohibited in the immediate vicinity of the system. No other EMI/RFI events were recorded by the licensee.

- PIR 970419136 reported the discovery of an anomaly in the port failure detection logic, during the installation of the enhanced firmware in Unit 1. Resolution of this issue involved the performance of minor system configuration changes to remove the console port 0 failure mechanism.

- PIR 970914106 describes a system architecture weakness that caused an alarm window to stay lit following a lamp test. The licensee's evaluation of this indicated that it did not affect an alarm coming in.

The inspector's review of the status of the Unit 1 system modifications determined that all changes previously implemented for Unit 2 were also implemented for Unit 1. In addition, the Unit 1 modifications were accomplished using the enhanced firmware as described under PIR 961004139.

In response to Violation No. 50-272 & 311/95-81-04, the licensee stated that they would pursue a design change that would replace the present OHA system with a new system, following the Unit restart. On December 11, 1997, PSE&G informed the NRC (letter No. LR-N970774) that they would no longer pursue a total system replacement. This decision was made "As a result of the success of the modifications and procedural changes" implemented for Unit 2.

The inspector confirmed that a variety of enhancements had been made both to the system design and to the system preventive maintenance program. In addition, the

licensee had added the system to the scope of the Maintenance Rule monitoring program. These physical and programmatic enhancements should improve the system reliability.

c. Conclusions

The overhead annunciator alarm system experienced several anomalies since the NRC review of the Unit 2 deficiencies resolution. These anomalies, however, appeared to be more nuisance and operator burdens than serious safety issues. Considering PSE&G's resolution of such anomalies, the system improvements developed, the success of such improvements, and the continuous monitoring of the system by the licensee, Restart Issue II.40 is closed for the Unit 1.

E2.20 (Closed) NRC Technical Restart Issue II.42: Auxiliary Feedwater Performance and Reliability (Unit 1)

a. Inspection Scope

The inspector reviewed the closure package for restart issue II.42 and all outstanding work orders for the Unit 1 auxiliary feed pumps (AFP). The inspector held discussions with system engineering personnel on auxiliary feedwater (AFW) system performance and readiness. The inspector also performed a field walkdown of the Unit 1 AFPs. This restart issue was previously reviewed by the NRC in IRs 96-17 and 96-18, for Unit 2.

b. Observations and Findings

The corrective actions taken for Unit 1 are the same as Unit 2. The only exception is that the turbine driven AFP (TDAFP) governor valve, 1MS53, has been modified with an upgraded valve stem and packing washers made of Inconel 718 and low sulfur content carbon spacers. This design modification was performed to eliminate governor valve stem corrosion. The Unit 2 MS53 valve will be modified during the next refueling outage. The inspector noted that the field work for the TDAFP governor design change had not been completed and is scheduled to be completed prior to entry into Mode 4. Several outstanding post maintenance tests remain to be performed and are scheduled for performance during system startup.

c. Conclusion

The corrective actions to resolve auxiliary feedwater performance issues are acceptable, and outstanding post maintenance testing has been scheduled for completion during system startup. Restart issue II.42 is considered closed for Unit 1.

E2.21 (Closed) NRC Technical Restart Item II.44: Emergency Core Cooling Switch over From Injection to Recirculation Mode (Unit 1)

a. Inspection Scope

The inspector reviewed the corrective actions taken by PSE&G to address NRC concerns regarding switch over of the Salem Unit 1 emergency core cooling systems from the injection to the sump recirculation mode of operation. These concerns were documented in NRC IR 97-11, and reported by the licensee in Licensee Event Report (LER) 97-09-01, "Past Operation of the Emergency Core Cooling System Outside the Plant Design Basis," dated June 27, 1997. While the reports focused on the semi-automatic switch over scheme at Salem Unit 2, similar concerns existed regarding the manual switch over at Unit 1. To address the Unit 1 concerns, the inspector reviewed applicable calculations and other PSE&G and Westinghouse documents.

b. Observations and Findings

Due to changes in postulated emergency core cooling system (ECCS) pump flow rates identified in NRC Information Notice 87-63, "Inadequate Net Positive Suction Head in Low Pressure Safety Systems," and other related issues (i.e., excessive residual heat removal pump flow during hot leg recirculation and excessive suction boost to high and intermediate head safety injection pumps), PSE&G changed the Unit 2 emergency operating procedures (EOPs) in 1994 such that a brief interruption of ECCS flow to the core was permitted to give the operators time to complete the switch over from the injection to the cold leg recirculation phase; that is, to switch pump suction from the refueling water storage tank (RWST) to the containment sump. In NRC IR 97-11, the NRC concluded that the EOP changes introduced an unreviewed safety question requiring NRC approval prior to implementation. The NRC also documented concerns regarding runout of RHR pumps beyond the limits shown in the vendor pump curves, and crediting containment overpressure in the calculations of available pump net positive suction head.

In response to IR 97-11 and in LER 97-09, the licensee committed to complete an RWST draindown analysis, and to take other corrective actions, to address the problem at Unit 1. The inspector verified that the following corrective actions had been taken by the licensee and that the associated 10 CFR 50.59 safety evaluations had been performed adequately:

- Revision of Technical Specification Section 3.5.2. This revision, described in License Amendment No. 200, clarified the hot leg recirculation flow paths required to be operable in operating modes 1 through 3.

- Revision of the RWST draindown analysis. This analysis calculated that plant operators will have 11.7 minutes (between the RWST Low and the Low-Low level alarms) to complete the switch over, assuming that: (a) both RHR pumps are stopped and their suction isolation valves (RH4) are shut, and (b) that operators immediately proceed to ensure that only one

containment spray pump is running. The inspector confirmed that procedure 1-EOP-LOCA-3 had been revised to incorporate these requirements. In addition, the inspector determined that EOP validation runs conducted in the plant simulator in November 1997 had shown that the operators had no trouble meeting the new time limits. The operator crews completed the LOCA scenario (which assumed a single failure of one RHR pump failing to stop) in 10 minutes or less.

- Revision of the Updated Final Safety Evaluation Report to incorporate the analysis and procedure changes described above.

- Revision of the RHR pump net positive suction head calculation. This revision removed the credit taken for containment overpressure, thereby conforming to the original plant design and licensing basis.

- Obtaining new RHR pump performance curves from the vendor. These curves show the net positive suction head requirements in higher flow regions and, thus, remove the need to extrapolate the requirements.

- Revision of operating mode 4 EOP procedure S1.OP-AB.LOCA-0001 to clarify the hot leg recirculation path through valve 1RH26.

- Placement of valve 1RH26 back into the licensee's Inservice Test (IST) and Generic Letter 89-10 motor-operated valve programs. The inspector verified the addition and reviewed the diagnostic test results and design-basis thrust requirements and concluded that the valve had adequate capability margin under the postulated accident conditions. In addition, the inspector verified that the licensee had added forward flow exercise tests of hot leg recirculation check valves 13/14RH27 to the IST program.

- Revision of procedure 1-EOP-LOCA-3 to resequence closure of valves 11/12SJ49. The inspector verified that the current torque switch settings of the valves were adequate for the new plant conditions under which they would be operated.

- Addition of the valve stroke time exercise tests to the IST program.

The inspector noted that the revised EOPs changed the treatment of a single failure of an RHR pump to stop. Previously, the operators were directed to shut the suction isolation valve of both pumps, which would have resulted in damaging the running pump. The revised procedure directs that the running ("failed") pump be used preferentially during the recirculation phase, thus "saving" the remaining pump should it be needed. The inspector concluded that the licensee's initiative demonstrated good sensitivity to optimizing the EOPs.

c. Conclusions

The licensee took effective action to correct deficiencies in the EOPs and plant design documents regarding switch over of ECCS pumps to cold and hot leg recirculation. The actions were acceptable for Unit 1 startup, and therefore, Restart Issue II.44 is closed.

E2.22 (Closed) NRC Technical Restart Issue II.45: Containment Fan Coil Unit Modification (Unit 1).

a. Inspection Scope

The licensee installed a modification to address potential water hammer and two phase flow conditions in the Containment Fan Coil Units (CFCUs), as identified in Generic Letter (GL) 96-06 and Licensee Event Report (LER) 50-272 & 311/96-020. In correspondence to the NRC staff dated January 28, March 27, April 24, June 3, and June 12, 1997, PSE&G described the modification being made to the Salem Unit 1 and 2 Service Water (SW) systems to address the GL issues. The modifications were reviewed in the NRC Safety Evaluation Report (SER) issued with Amendments 196 and 179 for Salem Units 1 and 2 Technical Specifications, dated June 19, 1997. The scope of this inspection was to review the changes made to the Salem Unit 1 design that differ from the modifications described in the previous PSE&G submittals and the NRC SER, to verify implementation and testing of the modification for Salem Unit 1, and to verify completion of the implementation of measures to ensure freeze protection for the Unit 2 CFCU modification.

b. Observations and Findings

The inspector reviewed the licensee's restart package for this technical issue which was accepted by the General Manager - Salem Operations on December 3, 1997, and the changes related to the Unit 1 CFCU modification, as documented in a letter from PSE&G to the NRC staff dated December 5, 1997. The changes made to the Salem Unit 1 modifications included: the elimination of system integrated testing; the use of constant flow bypass lines around the CFCU outlet valves instead of the installation of relief valves on CFCU piping for overpressure protection; and not installing volume boosters on the no. 12 component cooling water (CCW) heat exchanger SW flow control valves. The inspector discussed these changes with NRC Office of Nuclear Reactor Regulation (NRR) staff and determined that they were acceptable.

The inspector discussed the status of the implementation of the CFCU modification with the system manager and walked down portions of the Unit 1 and 2 modifications accompanied by the system manager. The inspector found that the installation and testing of the modification was essentially complete. In addition, installation of storage tank enclosures and building air handling units for both the Unit 1 and 2 modifications was completed and provided adequate measures to ensure freeze protection.

c. Conclusions

The licensee adequately completed the modification installation and testing of the Unit 1 containment fan coil units to address potential water hammer and two phase flow conditions. In addition, adequate measures to ensure freeze protection have been taken. Restart Issue II.45 for Unit 1 is closed.

E2.23 (Closed) NRC Programmatic Restart Issue III.a.4.1: Management of Engineering Backlog (Unit 1)

a. Inspection Scope

PSE&G's methods for managing the backlog size and assessing the significance of backlogged items on plant operation and safety was evaluated previously, as described in NRC IR 97-18. At that time the NRC concluded that the engineering backlog was being properly managed and that engineering management actively participated in the prioritization of emergent issues and, in so doing, remained aware of the content of the backlog.

The purpose of the current review was to evaluate the current backlog volume and the criteria used by PSE&G to categorize the Unit 1 items as post-restart. In addition, the inspector reviewed a sample of the post-restart items to ensure that they had been properly classified.

b. Observations and Findings

The backlog of engineering activities requiring closure at the time of the inspection consisted of approximately 8800 items in the corrective action and business process tracking system and approximately 2700 in the design change process. The backlog list included items from Hope Creek and Salem Unit 2 as well as Salem Unit 1.

To reduce the burden of the large backlog of engineering activities in the corrective action program, in November 1997, the licensee developed a plan to review the outstanding items and categorize them in related groups so that they could better prioritize the required work and more effectively reduce the backlog. Two teams of personnel from different disciplines were selected for this effort. The results of this screening was reviewed by Quality Assurance. Only a few misclassifications were found. In another effort, all design change requests (DCRs) and design change packages (DCPs) were reviewed to close item numbers that had been reserved but never used. The backlog identified above is the result of such screening efforts. PSE&G plans to reduce the backlog to only items less than 180 days old by the end of March 1999.

To address the correct classification of several items as post-restart, the inspector reviewed the list of Unit 1 DCRs and DCPs in the category designated by the licensee as "configuration" (approximately 300 items). The inspector found that almost all of the items had a 4BA status, indicating that the DCPs were in the

documentation closure phase. The inspector also reviewed, on a sampling basis, the DCR and DCP problem descriptions. No concerns were identified in this area.

In the corrective action program, the inspector reviewed the list of the Unit 1 items classified as "corrective actions for condition adverse to quality." From this list, the inspector selected six potentially safety-significant performance improvement requests (PIRs). Except as described below, an evaluation of the PIRs identified no Unit 1 issues that required addressing prior to restart.

PIR No. 970916253

As described in PIR No. 970916253, dated September 16, 1997, the licensee discovered an apparent test discrepancy between two breakers in panels 97-1 (Unit 1) and 97-2 (Unit 2). The licensee's review of the PIR determined that each panel contained three breakers. Two of the three breakers provided containment penetration protection and were being tested according to specified plans. The third breaker, however, was not shown on drawings and historically had not been tested or maintained. In the PIR the licensee recognized the possibility of the third breaker providing penetration protection. Therefore, to determine its function they planned to trace the circuit. Two action requests resulted, one for each unit.

Based on discussions with the licensee, in preparation for Unit 1 restart, the two penetration protection breakers in Unit 1 panel 97-1 were tested; the third breaker was conservatively tested. For Unit 2, as a result of the NRC questions regarding the subject PIR, the licensee traced the circuit from the third breaker and found that it fed through a containment penetration and provided power to three humidifiers. The breaker was not on the list of breakers requiring operability verification through periodic testing and had not undergone periodic inspection and preventive maintenance, as required by the Salem Technical Specifications. A new PIR (No. 980130176) was written and the breaker was subsequently opened, pending completion of appropriate surveillance testing.

Failure to perform surveillance testing of the breaker is a violation of penetration protection breaker surveillance requirements described in Sections 4.8.3.1.a.2 and 4.8.3.1.b of the Salem Technical Specifications. **(VIO 50-311/97-21-05)**

c. Conclusions

Although the quantity of backlogged engineering activities is large, the inspector found that activities are properly managed and prioritized. A sample review of the Unit 1 post-restart engineering backlog activities identified no issues that needed licensee resolution prior to Unit 1 restart. Therefore, Restart Issue III.a.4.1 is closed. However, in conjunction with this review, the inspector found the licensee had failed to perform required surveillance testing of a penetration protection breaker for Unit 2.

E2.24 (Closed) NRC Programmatic Restart Issue III.a.25: Vendor Manual Program (Unit 1)

a. Inspection Scope

The NRC's Readiness Assessment Team Inspection (RATI) for Unit 2 identified that a number of elements of the licensee's vendor document control program were weak as documented in RATI IR 97-80. The most significant of these weaknesses included: a large number of vendor recontacts remained to be completed; the backlog of vendor manual documents on site that had not been processed was significant; and there were no performance indicators developed and tracked to manage the backlog. During this inspection, the inspector reviewed the actions the licensee has taken to address these weaknesses.

b. Observations and Findings

The inspector reviewed the licensee's restart issue closure package for the Vendor Manual Program, which was reviewed by the Management Review Committee on November 20, 1997, and was approved by the General Manager- Salem Operations on November 25, 1997. In addition, the inspector reviewed licensee procedure NC.DE-AP.ZZ-0006, "Vendor Technical Document Control Program," Revision 11, and discussed the program with licensee staff.

The inspector verified that the licensee took action to address all the weaknesses identified during the RATI. Most significantly, to improve the quality and usefulness of the vendor contact process, the licensee has changed to a more rigorous contact on a three year cycle that is reflective of industry practice. The previous contact process yielded a vendor response rate of less than 3%, whereas the new process has yielded response rates greater than 95%. The number of vendors that were contacted in the previous program amounted to 254. With the new process, the licensee contacted 284 vendors in 1997, and identified another 170 "key vendors" to contact in 1998. These 454 "key" vendors will be assessed in 1999 to identify those that should remain in the vendor contact program. The remaining vendors will be scheduled in a three year recontact cycle with approximately 1/3 contacted in a calendar year.

The licensee is currently tracking the backlog of individual vendor documents (IVD) awaiting processing within the Vendor Engineering Group (VEG) and has developed a Vendor Document Performance Indicator (PI). As of December 1997, the PI showed that there were 540 IVDs (Salem and Hope Creek combined) in the backlog and that the backlog was projected to continue to rise through 1998 as the remaining 170 vendors are contacted. The inspector noted that this was significantly less than the 2710 vendor documents in backlog at the time of the RATI. The licensee indicated that none of the 540 IVDs contained technical changes classified as safety related or significant issues. The Vendor Document Group (VDG) supervisor indicated that he has been provided extra staff to support working off the backlog by the end of 1999. Procedure NC.DE-AP.ZZ-0006 requires that the IVDs be screened within 15 calendar days of receipt by the VEG in order to determine if an expedited evaluation is required. As of January 30, 1998,

the VDG supervisor indicated that all IVDs awaiting processing had been screened within the required 15 days. The supervisor indicated that this was an area they needed to closely continue to monitor and they were evaluating the need to maintain additional PIs for this area.

c. Conclusions

The inspector determined that the licensee has taken appropriate actions to address weaknesses previously identified in the Vendor Manual Program. Specifically, the licensee has implemented a more rigorous vendor recontact program, they have significantly reduced the backlog of vendor documents onsite requiring processing, and they have developed a performance indicator to track and manage the backlog and are evaluating the need for additional performance indicators.

E7 Quality Assurance in Engineering Activities

E7.1 (Closed) NRC Technical Restart Item II.16: NRC and QA Identified Numerous Inservice Testing Program Deficiencies - Quality Assurance of IST Program (Unit 1) (See also Sections E7.2 and E2.7)

a. Inspection Scope

The inspector reviewed PSE&G Quality Assurance Inservice Testing Program (IST) Audit that was performed from August 4 - 15, 1997, and interviewed IST program personnel. The purpose of the review was to assess the quality of the licensee's independent evaluation of the Salem IST program and to verify that the licensee's corrective actions were acceptable for startup of Unit 1.

b. Observations and Findings

The audit was performed by four QA auditors and two technical specialists independent of the PSE&G organization. The audit team evaluated IST program administration and documentation, procedures and test methods, data analysis and trending, scope, and corrective actions. Strengths were identified in the areas of tracking and trending of test data and component performance, program ownership, and administration. The licensee's findings in these areas were consistent with the inspector's observations as documented previously in NRC IR 96-20. Administrative procedures were maintained as controlled documents under the licensee's 10 CFR 50, Appendix B, Quality assurance program and were reviewed biennially. This centralized program document and the program basis data sheets that document the design and licensing basis of each component in the IST program exceeded ASME Code requirements and were considered to be a strength in PSE&G's program. The licensee demonstrated its computerized tracking and trending database to the inspector. The database was an effective means of monitoring component condition, and IST personnel were knowledgeable of current performance trends. The inspector found the licensee's threshold for initiating corrective action for degrading trends often exceeded Code requirements.

The inspector reviewed the corrective actions for eight audit findings. In each case the inspector found the licensee's corrective actions to be acceptable.

c. Conclusions

The licensee performed a broadly based and probing assessment of the Salem inservice test program. The licensee's corrective actions for the audit findings were prompt and effective. Tracking and trending of component performance were considered to be a program strength. This review supports closure of Restart Issue II.16.

E7.2 (Closed) NRC Technical Restart Item II.16: QA Identified Inservice Test Program Restart Items (Unit 1) (See also Sections E7.1 and E2.7)

a. Inspection Scope

The inspector reviewed the findings of an audit performed by Quality Assurance in 1995. These findings were described in PSE&G's closure package for Restart Issue II.16. The inspector also reviewed the licensee's corrective actions.

b. Observations and Findings

The inspector's review of the 1995 QA audit determined that nine findings were Unit 1 restart items. The inspector verified through review of IST program documents and procedures that the nine items had been completed satisfactorily for Unit 1 restart. Two of the findings are described below:

- PR 950807318 identified an inadequate test of "dual-clapper" check valves. The licensee had been checking closure of certain check valves by verifying a "clapping" sound as the disk hit the seat. However, since the valves had two disks, the potential existed that only one of the disks actually had shut. The procedures were revised to provide better methods of verifying valve closure.

- PR 960621158 identified an inadequate test of safety injection check valve SJ34 with Tavg less than 350 degrees Fahrenheit. Due to a procedure error, an upstream isolation valve (SJ134) was shut when the differential pressure across valve SJ34 was measured to verify closure. As a result, the observed differential pressure actually was occurring across the isolation valve rather than the check valve. The licensee revised the test procedure to correct the error.

c. Conclusions

Subsequent testing of the above valves confirmed their operability. The licensee's closure of the 1995 QA audit restart items was acceptable for Unit 1 restart. However, failure to test certain safety injection and service water check valves adequately (PRs 950807318 and 960621158) was a violation of Code

requirements. This licensee-identified and corrected violation is being treated as a Non-Cited Violation consistent with Section VII.B.1 of the NRC Enforcement Policy. **(NCV 50-272/97-21-06)**

E8 Miscellaneous Engineering Issues

E8.1 (Closed) Unresolved Item 50-272/90-81-13:Cable Separation

During a 1990 integrated performance assessment team (IPAT) inspection, the NRC identified approximately 40 cables (in both units) that did not meet the FSAR separation criteria of 18 inches vertically and 12 inches horizontally. NRC issued a 10 CFR 50.59 violation in IR 97-05. As further documented in IR 97-08 and Section E2.11 of this report, the licensee revised the separation criteria stated in the UFSAR and took appropriate actions to correct the deviations in both Units. This item is closed.

E8.2 (Closed) Unresolved Item 50-272/93-19-03:2R15 Radiation Monitor System Inoperability

The condenser exhaust noble gas effluent process monitor, 2RM15, was declared inoperable because of observed water in the sample line. Originally, the licensee attributed the problem to condenser shell ball check float valves that stuck open and allowed water and debris to enter the system. Subsequently, their evaluation found that original design weaknesses had rendered the reliability of the 2RM15 monitor less than acceptable. As a result, even when clean, the valves would not prevent water from entering the sample line.

To resolve the reliability issue, PSE&G redesigned the system, replacing the ball check valves with loop seals and the vacuum pump with a vacuum limited pump (DCP 1SC-2300). A review of the status of this DCP determined that all activities had been completed. Resolution of the Unit 1 radiation monitoring issues in general was evaluated in Section E2.15 of this report.

The inspector did not identify any violations of NRC requirements. This item is closed.

E8.3 (Closed) Unresolved Item 50-272/93-21-02:Containment Isolation - 1R11A Radiation Monitor Alarms

This item was open to followup on the licensee's resolution of several 1R11A malfunctions that once resulted in an engineered safety feature (ESF) actuation and isolation of the containment vent valves. Subsequent trouble shooting by the licensee determined that spikes were induced on the cable by the paper tear switch and time-delay relays in the MX-2A assembly. Replacement of the circuit assembly eliminated the spikes. This work was completed in 1993.

Failure by the licensee to thoroughly evaluate and correct the 1R11A malfunctions is a violation of the 10 CFR 50, Appendix B, Criterion XVI requirements. Since the

NRC took significant enforcement actions for Salem failure to identify and correct conditions adverse to quality, and since PSE&G voluntarily maintained both Salem units shut down to address equipment and enforcement deficiencies, this self-identified and corrected violation, involving past performance deficiencies, is being treated as a Non-Cited Violation consistent with Section VII.B.1 of the NRC Enforcement Policy. **(NCV 50-272/97-21-07)**

Resolution of the Unit 1 radiation monitoring issues in general was evaluated in Section E2.15 of this report. This item is closed.

E8.4 (Closed) Unresolved Item 50-272/93-26-01: Evaluation of Pressure Locking and Thermal Binding of Gate Valves

Pressure locking and thermal binding of wedge-type gate valves concerns were originally expressed in IR 93-26. The status of the licensee's action to address those concerns was reviewed and updated in IR 96-07. At that time, some of the valve-related issues were closed. The remaining issues pertaining to this unresolved item were evaluated and found acceptable in IR 96-20 for Unit 2 and Section E2.14 of this report for Unit 1. Because the pressure locking and thermal binding issues were identified during the licensee's review of valve susceptibility under the GL-89-10 program, this already corrected violation is being treated as a Non-Cited Violation, consistent with Section VII.B.1 of the NRC Enforcement Policy. **(NCV 50-272/97-21-08)** This item is closed.

E8.5 (Closed) Unresolved Item 50-272 & 311/94-04-01: Power Range Neutron Detectors

Each Salem unit uses four power range neutron detector assemblies supplied by Westinghouse. Each assembly, consisting of two neutron detectors (top and bottom detectors), has three electrical connections: one for the power supplies; one for the top detector signal; and one for the bottom detector signal. During a 1993 Quality Assurance (QA) audit (Report 93-101), the PSE&G QA auditor raised a concern regarding the qualification of the detectors. His concern was that, following a small size steam line break (0.1 ft^2 to 0.25 ft^2) inside the reactor containment, the harsh environment in the containment could cause the power range neutron detectors to malfunction and the control rod to move in an outward direction, before the reactor trip.

The NRC reviewed the functional capabilities of the neutron detector assemblies, interconnecting cables, and terminations, following a postulated small size steam line break, in December 1994 (IR 94-33) and again in January 1997 (IR 97-02). In this latter report the inspector concluded that the qualification of the field cables and Raychem seals had been acceptably demonstrated and that the design life of the power range neutron detectors was sufficient to cover 40 years of normal plant operation. The inspector also concluded that the licensee had provided sufficient additional information to show that a potential malfunction of the detectors during a small steam line break would not occur. However, the detectors were not included in the Salem Master List of Electrical Equipment for Environmental Qualification. Apparently, this was based on an exemption considered acceptable by an NRC contractor in 1984.

Qualification requirements were also discussed in a conference call between the NRC and PSE&G management personnel on September 4, 1997. PSE&G stated that they would either add the item to the Master List or demonstrate that the equipment did not require qualification.

During the current review, the inspector determined that the licensee had evaluated the environmental qualification of the detectors under the postulated accident and added them to the Master List. This analysis, titled "Nuclear Instrumentation System (NIS) Power Range Neutron Detector System Operability and Equipment Qualification Determination - Salem Generating Station," evaluated the maximum environmental conditions that could be attained during a small steam line break and showed that the detector assemblies and interconnecting cables were qualified as installed and would not malfunction during the stated event. This item is closed. However, the licensee's failure to include the neutron detectors in the Salem Master List of equipment requiring environmental qualification is a violation of 10 CFR 50.49. **(VIO 50-272 &311/97-21-09)**

E8.6 (Closed) Unresolved Item 50-272/95-17-04: Adequacy of EDG Loading Margin

Following the electrical distribution system functional inspection, the Salem emergency diesel generator (EDG) load margin and correctness of the loads used in the EDG calculations was questioned by the NRC during various system reviews, including the subject inspection. The NRC has reviewed the EDG load calculations and concluded that the EDGs of both Units have a small but sufficient margin (IR 97-10 and section E2.3 of this report). Because the unresolved issue involved the adequacy of the EDG load margin and the inspection concluded that sufficient margin existed, no violation of NRC requirements occurred. This item is closed.

E8.7 (Closed) Unresolved Item 50-272 & 311/96-01-09: CR205 Relay Application in Safety-Related Applications.

This item was opened as a result of Hope Creek engineering personnel identifying two issues with Model CR205 machine tool relays manufactured by General Electric. The two issues involved the use of no. 16 AWG wires with terminal lugs designed for no. 14 AWG minimum wire, and the chattering and hanging-up of the relay auxiliary contacts. As stated in IR 96-01, the licensee had determined that some CR205 relays were being used in safety-related applications. Therefore, they had initiated a detailed review.

During the current review, the inspector discussed the status of the licensee's investigation. He determined that the CR205 relays were being used extensively in safety-related motor control centers. The licensee, however, provided evidence that the offset auxiliary contacts susceptible to chattering and hanging up were not being used at Salem. The inspector also confirmed that the mismatch between wire and lug size did not exist at the Salem plant. Because the NRC concerns regarding the relay were not applicable to Salem, no violation of NRC requirements existed. This item is closed.

E8.8 (Closed) Unresolved Item 50-272 & 311/96-13-03: EDG Load Fluctuations

Emergency Diesel Generator load fluctuations was the subject of item II.11 of the NRC Restart Plan for Salem. The NRC reviewed the issues associated with the load fluctuations experienced by the licensee, the subsequent evaluation and the actions that were taken to prevent recurrence. The NRC found those actions acceptable, as specified in inspection report 96-13.

At the time of the restart item closure, the inspector determined that some of the corrective actions that had been planned were still incomplete. An item was open to monitor closure of those actions and to evaluate their outcome. A review of those items during the current inspection period determined that all actions but one remained open. No concerns were identified with the licensee's closure of the items. The remaining item pertaining to future evaluations by the licensee of the governor control system potential upgrade alternatives, is a long term item. Because the unresolved item involved solely the NRC followup of planned PSE&G actions to prevent potential EDG load fluctuations in the future, no violation of NRC requirements existed. This issue is closed.

E8.9 (Closed) Unresolved Item 50-272 & 311/96-16-03: Followup of Fuse-Related Discrepancies

While reviewing the fuse control program, the inspector determined that a licensee contractor had performed an assessment of fuse and breaker coordination at the Salem station, Report SA96-011, dated April 25, 1996. This assessment had addressed short circuit and coordination studies for the vital ac and dc systems, including Appendix R equipment and penetration protection. The objective of the assessment was to compare the Salem design and calculations with the information and guidance provided in applicable standards and licensing documents. This assessment identified several coordination discrepancies. The licensee evaluated the assessment results and provided justifications for the current plant conditions. They had, nonetheless, made plans to reevaluate and update the old calculations by June 30, 1997, as documented in PIRs 960425091 and 99.

As a followup to the original observations, the inspector reviewed, again, Report No. SA96-011 and the licensee's resolution of the observations stated therein. The inspector reviewed in detail three of the eight issues regarding: (1) breaker lineups that were not prevented by operating procedures, but that could result in higher short circuit current than had been calculated with the analyzed lineups; (2) lack of coordination between various breakers; and (3) the use of one-second motor starting time in the breaker and relay coordination studies.

The licensee's original review of the first issue concluded that the lineups suggested by the study were either unreasonable or they were not a concern with a single-unit operation (only Unit 2 was undergoing startup process at that time). Also, based on their conclusion that the short circuit ratings appeared to not be impacted, they deferred their detailed review until March 31, 1998. The inspector's review of the examples provided in the report determined that the lineup identified as, "Both Units

have their Group Busses on the Station Power Transformer" (SPT), was more probable with single-unit operation than with both units at 100%. PSE&G engineering continued to believe that the short circuit rating of the equipment would not be impacted. They, nonetheless, prepared an Action Request (980129154) to instruct the operating staff to restrain from running turbine generator TG3 with both units aligned to the respective SPT and to revise operating procedure S3.OP-SO.JET-0001(Q) accordingly. PSE&G considered this to be a temporary resolution of the issue while they evaluate the impact of the lineup on the available maximum short circuit current previously calculated.

Regarding the second issue, the licensee's evaluation determined that breaker miscoordinations existed only in the instantaneous (short circuit) area. Because the short circuit calculation (ES-13.006) had conservatively assumed that all breakers would be affected by motor contribution to the fault, the licensee reevaluated, as applicable, available short circuit currents without motor contribution. Several breaker settings remained uncoordinated. For the purpose of updating the calculation the licensee issued a performance improvement request (980115218). This PIR also concluded that the miscoordination had no safety impact because the cable separation criteria used ensured that an internal fault in one channel would not propagate to the redundant channel.

To address the third issue, PSE&G evaluated the vendor-supplied motor starting curves and determined that in all cases the motor would reach full speed in advance of the breaker trip device actuating. Only in one case was the motor starting time-current curve, at 80% voltage, just below the time-current curve of the breaker trip device.

The first two issues relate to short circuit availability and to the ability of the breaker closest to the fault to interrupt the fault current. In most cases, short circuits are not a nuclear safety concern because of the redundancy provided in the design of electrical systems. However, a properly designed electrical system also assures that plant transients are prevented. In the case of circuit breakers supplying nonsafety-related loads from safety related buses, upstream-downstream coordination of circuit protectors is used as a means to isolate safety from nonsafety-related circuits. Although the PIRs that PSE&G prepared properly addressed the inspector's questions with these issues, PSE&G's actions, when these issues were originally identified, were narrowly focused.

Regarding the third item, the licensee showed that although they had not specifically compared individual motor starting times to the breaker trip characteristic, in calculation No. ES-E15-014, Revision 1, they had compared them generically by motor and breaker type and found that the breaker trip settings were sufficiently high to prevent a spurious breaker trip, during a motor start at degraded voltage conditions.

Based on the results of the above review, no violation of NRC requirements occurred. This item is closed.

E8.10 (Closed) Violation 50-272/97-02-02: Failure to Test MCCBs in Instantaneous Region

The NRC review of the results of molded-case circuit breaker testing determined that several electrical penetration protection circuit breakers (e.g., 2GP14X and 10X and 2EP2X and 3X) had not been tested in the instantaneous region as required by Test Procedure SC.MD-ST.ZZ-0004(Q). The NRC reviewed PSE&G's response to the violation, letter No. LR-N970300, dated May 28, 1997, and actions to correct the Unit 2 circuit breaker testing deficiencies previously, as documented in IR 97-16. This item remained open, however, pending confirmation that the Unit 1 MCCBs have been tested.

As stated in Section E2.4 of this report, the inspector confirmed that the Unit 1 molded-case circuit breakers requiring testing had been properly tested. This item is closed.

E8.11 (Closed) Violation 50-272 & 311/97-05-01: Inadequate Implementation of 10 CFR 50.59 Requirements

On June 3, 1997, the NRC issued a Notice of Violation for failure to provide adequate bases for plant design configurations that differed from the FSAR description. The NOV cited two examples. In the first example, PSE&G revised the UFSAR to allow cables of redundant channels to be separated by a distance less than that previously accepted by the NRC. In the second example, PSE&G failed to prepare a 10 CFR 50.59 safety evaluation for UFSAR revisions that permitted cable separation configurations not allowed or not specifically allowed by the previous UFSAR revision.

The NRC documented their review of the licensee's response to the NOV, Letter No. LR-N970402, dated June 27, 1997, in IR 97-16. In this report the inspector concluded that PSE&G had taken acceptable actions to improve the quality and accuracy of safety evaluations. However, the item was left open because walkdowns to address the Unit 1 cable separation and the implementation of the root cause analysis recommendations were still ongoing.

As stated in Section E2.11, above, the corrective actions to address cable separation deviations were completed. In addition, the inspector confirmed that the planned enhancements to the safety evaluation review and feedback process had been implemented. This item is closed.

E8.12 (Closed) Unresolved Item 50-272 & 311/97-16-02: Cable Separation Within Panels and Cabinets

During walkdowns to address NRC Restart Item II.21, Wiring Separation & Redundancy Concerns with RG 1.97 Instruments and Cable Separation, the inspector observed apparent cable separation deviations inside relay cabinets. These deviations involved the bundling together of safety-related cables in one channel with nonsafety-related cables associated with the other redundant channels.

To address the NRC observations, PSE&G provided an analysis, No. S-C-VAR-CEE-0389, Revision 0, dated June 1990, that evaluated the design bases and licensing commitments of the plant relative to cable separation and electrical isolation and provided the criteria to be used in the development of a Salem-specific technical standard. PSE&G also provided engineering evaluation No. S-2-VAR-EEE-1228, Revision 0, "Cable Separation Evaluation inside the Cabinets TP 25-1 and TP 28-1." to address the specific deviations identified by the inspector.

The inspector's original review of the first analysis (No. S-C-VAR-CEE-0389) identified no areas of concern. However, his review of analysis No. S-2-VAR-EEE-1228 concluded that, although it had sufficiently proven that the functions of the cables in question were nonredundant, the analysis was incomplete, in that it had not specifically addressed failure modes of affected circuits and components. This analysis should have been performed "to assure that the single failure criterion is not violated," as recommended in analysis No. S-C-VAR-CEE-0389.

Following a series of meetings that included PSE&G and NRC management personnel, PSE&G evaluated all the circuits in the Bailey system termination cabinets, including those termination cabinets that had been questioned by the NRC, and concluded that faults affecting nonsafety-related cables could not damage two or more redundant channels. This was demonstrated by showing that acceptable coordination existed between the circuit protector of the nonsafety-related equipment and cables and the upstream circuit protectors. The inspector reached the same conclusion by independently verifying functions, voltages and protection of the circuits originally questioned.

The inspector reviewed Revision 2 of engineering evaluation S-2-VAR-EEE-1228 and confirmed the comprehensiveness of the analysis. As specifically requested by the NRC, in the analysis, the licensee confirmed that the Bailey system cabinets were the only place where the condition existed and, therefore, the results of the analysis were bounding of all cabinets at Salem. Based on the above review, no violation of NRC requirements occurred. This item is closed.

E8.13 (Closed) LER 50-272/95-012: adequacy of turbine driven auxiliary feed water pump enclosures. In early November 1995, the licensee discovered that assumptions in the high energy line break (HELB) analysis for the turbine driven auxiliary feed water pump (TDAFP) enclosure did not match as-built conditions. In particular, the HELB analysis assumed that the ABS-6 backdraft damper for the TDAFP enclosure would open instantaneously upon an HELB, and that the full open position of the ABS-6 damper would provide 100 percent of the damper opening area for pressure relief. Time delays exist between the pressure reaching the ABS-6 opening setpoint and the damper reaching the full open position. Additionally, the full open position area of the ABS-6 damper is less than 100 percent of the available area. These discrepancies could allow pressure in the enclosure to exceed design pressure during a HELB.

The inspector reviewed the corrective actions taken by the licensee, as detailed in the LER. A design modification to the Unit 1 and Unit 2 TDAFP enclosures has

been installed under the design change packages (DCP) 1EC-3595 and 2EC-3522, respectively. These DCPs replaced the ABS-6 dampers with spring loaded blow out panels, and sealed the TDAFP enclosure floor drains to eliminate alternate paths to adjacent spaces. Through field inspections of the TDAFP enclosures, the inspector verified that these DCPs had been properly implemented. The licensee has also evaluated the HELB analyses for all spaces containing air operated backdraft dampers to ensure that no other over pressurization possibilities exist. The inspector concluded that these corrective actions were adequate, and this LER is closed. This licensee identified and corrected violation of 10 CFR 50, Appendix B, Criterion III is being treated as a Non-Cited Violation consistent with Section VII.B.1 of the NRC Enforcement Policy. **(NCV 50-272&311/97-21-10)**

E8.14 (Closed) LER 50-272/95-023-01: Failure to Plug Steam Generator Tubes due to Missed Eddy Current Indications. This supplement to LER 95-023 was submitted to discuss the cause and safety significance of the event. Because this issue was previously reviewed and discussed in NRC Inspection Reports 95-17, 96-10, and 97-05, and LER 95-023 was closed in IR 95-19, the inspector performed an in-office review of the information provided in this LER supplement. The inspector found that no new information was provided in the supplement, and that no additional inspection effort was warranted. Therefore, this LER supplement is closed.

E8.15 (Closed) LER 50-272/96-020: Containment Fan Coil Units Outside Plant Design Basis. On August 20, 1996, engineering personnel concluded that both of the Salem units had the potential to operate outside the design basis. This condition resulted from a 1976 startup test modification that added approximately thirty seconds of time delay in the isolation of non-essential service water loads. As a result of the delay in isolating non-essential portions of the service water system, design basis service water flows to the CFCUs in certain single failure accident scenarios could not be achieved in the Technical Specification limit of less than or equal to 45 seconds for accidents. This is a violation of 10 CFR 50 Appendix B, Criterion III, Design Control. Also, in examining the impact of Westinghouse Nuclear Safety Advisory Letter 96-003, an engineering review identified that as service water was being restored to the CFCU, water trapped in the CFCU would be subject to significant thermal expansion due to the delay in opening the CFCU flow control valves. Significant thermal expansion could result in pressurization of CFCU components and associated SW piping beyond design limits.

As discussed in Section E2.22 of this report, the licensee has implemented adequate modifications to the Unit 1 and 2 CFCUs to address the concerns identified in this LER, as well as GL 96-06. Therefore, this licensee-identified and corrected violation of 10 CFR 50 Appendix B, Criterion III, involving past design deficiencies, is being treated as a Non-Cited Violation, consistent with Section VII.B.3 of the NRC Enforcement Policy. **(NCV 50-272 & 311/97-21-11)**

E8.16 (Closed) LER 50-272/96-030: Alignment of Back-Up Pressurizer Heaters for Emergency Power Does Not Meet Separation Criteria

In September 1996, PSE&G completed their review of the separation of the cables supplying power to the Salem pressurizer heaters. They found that, when the cables supplying power to the back-up pressurizer heaters left the cable tray in their free air route to the heaters, they did not meet the required physical separation stated in the UFSAR. Separation was a concern when the back-up heaters were aligned to receive power from the vital buses. The purpose of the on-site review of this item was to evaluate the licensee's corrective actions to address the identified separation deviation.

Cable separation, in general, was the subject of item II.21 of the NRC Restart Plan for Salem. As stated in IR 97-08 and section E2.11 of this report, known deviations in Unit 1 and Unit 2 were addressed and properly corrected by PSE&G. For this specific issue, the inspector determined that, since cable separation became an issue only in the emergency mode, PSE&G achieved compliance with the FSAR statements by revising the operating procedure to ensure that two channels would not be energized at the same time. The inspector verified that the applicable procedure had been revised. The inspector concluded that the licensee had properly addressed the separation issue. This item is closed.

This violation of the plant cable separation requirements was identified by the licensee and corrected when identified. Based on the above this violation is being treated as a non-cited violation, consistent with Section VII.B.1 of the NRC Enforcement Policy. **(NCV 50-272&311/97-21-12)**

E8.17 (Closed) LER 50-272/96-036: 28 Vdc Battery Capacity Exceeded

On November 6, 1996, during a review of work order 941026182, dated November 10, 1994, for the replacement of Bailey Type RZ pushbutton stations for Unit 2 control room consoles, the licensee identified that the replacement lamps listed on the work order were different than those listed in the vendor manual and applicable drawing. The difference between these documents was that the work order specified lamps rated 60 milliamperes (mA), whereas the other documents specified lamps that were rated 40 mA. The purpose of the on-site review of this LER was to evaluate the adequacy of PSE&G's action to correct their identified discrepancy.

The inspector's review of this issue determined that the licensee had reviewed it and concluded that, with the increased load, the 28 Vdc battery would not be able to provide the required voltage to all the loads, during a loss of coolant accident with loss of offsite power. The inspector's review also determined that incorrect (60 mA) bulbs had been used in lieu of the 40 mA bulbs. PSE&G promptly rectified the deficiency by replacing the oversized lamps with correct ones. Also, PSE&G revised the applicable procedures to specify 40 mA bulbs. Based on the inspector's confirmation that the appropriate actions had been completed, this item is closed. However, this licensee-identified and corrected violation of the Salem Appendix B

program is being treated as a Non-Cited Violation, consistent with Section VII.B.1 of the NRC Enforcement Policy. **(NCV 50-272 & 311/97-21-13)**

E8.18 (Closed) LER 50-272/97-004: Inadequate Surveillance Testing of Molded Case Circuit Breakers

This licensee event report stems from an NRC-identified issue regarding surveillance testing of molded-case circuit breakers used for containment penetration conductor overcurrent protection. The NRC finding resulted in a violation of the NRC requirements, as documented in IR 97-02. The NRC on-site verification that appropriate actions had been taken by the licensee to address this violation and testing of molded-case circuit breakers, in general, is documented in sections E8.10 and E2.4 of this report, respectively. The inspector's verification also confirmed that the molded-case circuit breakers involved with the subject LER had been properly tested. This item is closed.

IV. Plant Support

R1 Radiological Protection and Chemistry (RP&C) Controls (71750, 83750 & 92904)

R1.1 As Low As Is Reasonably Achievable (ALARA)

a. Inspection Scope

The inspector reviewed the licensee's program for tracking and controlling individual and collective exposure to ensure exposures are as low as reasonably achievable. Document reviews and interviews were conducted for this assessment.

b. Observations and Findings

The licensee has an exposure control program designed to limit individual exposures per entry to low levels typically 15-20 mrem for all areas including high radiation area entries. Electronic dosimeter alarms are utilized to control the individual exposure entry limits. For entries that are expected to require more exposure, an ALARA Planning Checklist must be completed and a specific staytime and exposure estimate is determined before each entry with a specific electronic dosimeter alarm setpoint provided. This exposure control method has proved effective in emphasizing exposure minimization with the individual workers and has provided effective control of individual doses.

Notwithstanding, collective exposure is not as well managed. Collective exposure estimating is based on historical values (exposure per day during operations or outages multiplied by the number of days). This top-down exposure estimating method does not incorporate details of work planning and is not integrated with the licensee's work week management program.

At Salem, work planning is organized into work weeks, however, ALARA planning does not provide planned work week exposure estimates as a performance indicator. The licensee indicated that 99% of collective dose is accrued by individual exposures below the ALARA planning threshold level. Estimates of collective exposures for work orders are provided to the maintenance work order computer data base. For work management control, a different scheduling software is utilized that does not provide the exposure information and therefore the value of estimated exposure for each work week has not been made available for performance tracking purposes. The licensee indicated that in 1998 a new company-wide relational database will replace all current network computer software systems. The ALARA group plans on utilizing the new computer platform to assess the scheduled work order exposure estimates to develop better exposure information and ALARA performance data.

The collective exposure goal for 1997 was 85 person-rem, based on both units being returned to operation and did not include carryover of steam generator replacement exposures. By mid-December the Salem 1997 collective exposure was 79 person-rem. Assuming an early 1998 startup of Unit 1, the licensee estimates approximately 42.5 person-rem for 1998.

c. Conclusions

The licensee's exposure control program continues to emphasize the control of individual exposures, which provides workers with very good attention and involvement in minimizing individual exposures. Better integration of the ALARA program with the work week management program could enhance overall ALARA performance.

R1.2 Dosimetry Discrepancies

a. Inspection Scope

The inspector reviewed the handling of personnel exposure result discrepancies through a review of documents and interviews with the dosimetry staff.

b. Observations and Findings

The inspector reviewed the licensee's handling of exposure discrepancies for the second quarter of 1997. Discrepancies between thermoluminescent dosimeter (TLD) and electronic dosimeter readings are defined by licensee procedure to be investigated when the dosimeter results for any individual are greater than 100 mrem per quarter and the dosimetry comparisons differ by greater than 20%. Nineteen individuals were identified by the licensee in this category for the second quarter of 1997. The inspector reviewed the investigation and disposition of these dosimetry discrepancies. Sixteen out of nineteen cases indicated electronic dosimeter results higher than TLD results by greater than 20%. The licensee makes comparisons of collective exposure by dosimeter type which indicates a very close correlation between TLDs and electronic dosimeters of less than 5% overall. The TLD National Voluntary Laboratory Accreditation Program (NVLAP) requirements

specify ±35% accuracy and the electronic dosimeters are calibrated onsite to read within ±10% accuracy. The inspector noted that for the sixteen cases where the electronic dosimeter read >20% higher than the TLD, the licensee assigned the lower TLD result in 15 of the cases cited based on a reverification of the TLD read analysis. No further investigation of the electronic dosimeter results were conducted to discount the validity of this dose information.

The inspector further noted that procedure no. NC.RP-TI.ZZ-0304(Q), Rev. 2, "Dosimetry Action Reports" required station RP supervision to evaluate dose discrepancies greater than 300 mrem, which would involve a review of worker time and dose rate evaluations as an evaluation tool to assign doses appropriately.

c. Conclusions

Dosimetry discrepancies were, in some cases, non-conservatively dispositioned for personnel exposure record purposes. In all these cases, only minor exposures were effected. The lack of exposure discrepancy investigation guidance is being addressed by the licensee to strengthen this program area.

R1.3 Internal Exposure Program

a. Inspection Scope

The inspector reviewed recent whole body count results, reviewed the whole body counter operator training and qualifications, and reviewed the status of the internal exposure program. This evaluation consisted of a review of documents and interviews with the RP staff.

b. Observations and Findings

A review of positive whole body counts since April 1997, indicated that there has been no reportable internal exposures for Salem or Hope Creek during this time period. Only one individual had a recorded internal exposure of 15 mrem which was below the licensee's reporting threshold of 50 mrem. Effective contamination control programs at Salem and Hope Creek stations have eliminated measurable internal exposures to personnel.

Internal exposure measurement and exposure calculation program capability has been weak and revisited regularly over the last three years. During this inspection, the licensee indicated plans for correcting the previously identified weaknesses in investigative whole body counting and in internal dose assessment procedures. During this year, the licensee reestablished calibration of the germanium detector whole body counter for investigative whole body counting to ensure the capability for accurate bioassay measurements when needed. However, the germanium whole body counter utilizes outdated software that calculates MPC-hours and maximum percent body burden, both outdated units and limits since 10 CFR 20 was revised in January 1994. The licensee indicated that during December 1997 and January 1998, the software would be updated to be consistent with the current

regulations, and that the nimbin electronics package would be replaced with a computer driven electronics package.

The inspector reviewed the whole body counter operator training qualifications and reviewed the training lesson plan material. The current whole body counter operator was observed by the inspector to exhibit weaknesses in utilizing the whole body counter to obtain a fine gain adjustment during daily whole body counter calibration checks. The inspector verified that the operator had been trained in whole body counter operations in March of 1993. The inspector reviewed lesson plan 04703 for whole body counter training and noted that basic gamma spectroscopy theory and instrument descriptions were provided but very little training was provided in how to operate the equipment. For example, no instruction was provided for a fine gain adjustment or instruction in how to perform a spectrum review of regions of interest. Also, the lesson plan was outdated utilizing MPC-hours and MPBB units. Since the current whole body counter operator was trained before the regulations changed, and there have not been any reported internal exposures for Hope Creek or Salem stations during the intervening time, there is no significance to this finding. However, the licensee indicated that after the germanium whole body counter hardware and software upgrades are completed, the whole body counter operation lesson plan will be revised and the current operator will be retrained by the end of second quarter 1998.

c. Conclusions

Excellent contamination control practices at Salem and Hope Creek stations have resulted in no reported internal exposures. The internal exposure program capability has been reported to be weak over the last three years and has begun to improve. Further hardware and software upgrades are planned for early 1998, which will include personnel training on program revisions and implementing procedures.

R2 Status of RP&C Facilities and Equipment

R2.1 Plant Tours

a. Inspection Scope

During this inspection, the inspector conducted numerous tours of the plant during operating conditions for Unit 2 and extended outage conditions for Unit 1.

b. Observations and Findings

In the outside plant areas within the protected area, several large radioactive material containers containing cranes were minimally posted (one or two sides) and many of the postings were coming loose due to weather deterioration. In Unit 1 Auxiliary Building 84-foot elevation, a charging pump tool box was posted with a contamination area sign on one end while the other end was not posted. In the Unit 2 Auxiliary Building, 84-foot elevation dose rates were generally less than 0.5 mrem/hr, however, while entering the Letdown Heat Exchanger Control Panel

labyrinth, dose rates increased to 10-25 mrem/hr general area with no radiological postings to inform workers of the elevated dose rates. None of the mentioned radiological posting discrepancies were violations of regulatory requirements.

c. Conclusions

The inspector noted that all required radiological postings and locked areas were within regulatory requirements and that the areas were clear of unnecessary equipment and free of safety hazards. Several minor posting weaknesses were observed indicating the need for continued diligence in this area.

R2.2 Electronic Dosimetry Calibrations

a. Inspection Scope

The inspector reviewed the licensee's electronic dosimeter calibration facility, dosimeter calibration records, and conducted interviews with cognizant personnel.

b. Observations and Findings

The ALNOR electronic dosimeters are calibrated every six months at an onsite instrument calibration facility utilizing a controlled calibrated cesium-137 source to calibrate each dosimeter to two integrated dose values with an acceptance criteria of ±10%. Alarm testing was also included in the calibrations. Appropriate calibration geometries and source calibration data were utilized, and selected dosimeter calibration records were on file as required.

c. Conclusions

The licensee's electronic dosimeter calibration program was effectively implemented in accordance with station procedures and regulatory requirements.

R5 Staff Training and Qualification in RP&C

R5.1 RP Technician Training

a. Inspection Scope

In a previous Hope Creek inspection report (50-354/96-09), it was noted that the licensee's continuing training program for RP technicians did not provide for periodic review of RP fundamentals. The RP technician training program is common to both Hope Creek and Salem and therefore, the earlier finding was also applicable to Salem. The inspector reviewed the licensee's actions to address this concern during this inspection through interviews and review of RP fundamentals examination results.

b. Observations and Findings

During the most recent Salem RP technician continuing training cycle that ended in early December 1997, the licensee administered the Mid-Atlantic Nuclear Training Group (MANTG) generic RP technician examination to the Salem RP technicians to assess their RP knowledge level. An 80% or higher grade is considered passing as applied to contractor RP technician applicants to the Station. The results of this examination indicated that 90% of the Salem RP technicians received a grade below 80% for one or more of the five subject areas. One on one remediation training was conducted to recover the revealed deficient areas. Similar results were obtained when the MANTG exam was administered to the Hope Creek RP technicians during continuing training in the Spring of 1997.

During this inspection, the licensee developed a corrective action plan that consisted of review and testing of all Hope Creek and Salem RP technicians in all RP technician initial qualification areas through a combination of classroom training and on the job evaluations. The inspector determined that the plan was comprehensive. The licensee estimates that all classroom training should be completed by the end of 1998. Revisions to the on the job evaluations should be complete by the end of July 1998, with the station RP organizations completing the skill requalifications by the end of 1998.

c. Conclusions

The licensee has self-identified significant weaknesses in the RP technician continuing training program. Both Salem and Hope Creek RP technicians scored poorly on a test of RP fundamentals. Appropriate short term corrective actions and long term plans are in place to correct the identified deficiencies. This issue was licensee identified with appropriate corrective actions taken or planned.

R7 Quality Assurance in RP&C Activities

R7.1 RP Program Oversight

a. Inspection Scope

The inspector reviewed the licensee's quality assurance audits and surveillances, RP problem reporting and corrective action program, and the RP self-assessment program to assess the adequacy of the RP program oversight. This review consisted of a review of reports and interviews with licensee personnel.

b. Observations and Findings

The licensee conducted a combined Salem/Hope Creek RP program audit (no. 97-150) on April 21 - May 2, 1997. This audit was performed with four technical specialists which included two individuals from other utilities. The audit was very detailed and included various RP subject areas, however, it did not cover all RP areas. A few weaknesses were identified in RP instrument records and in design

control of long-term shielding locations. These issues were tracked and dispositioned appropriately.

The licensee also conducted independent surveillances of RP activities. The inspector reviewed the surveillance reports from April through November 1997. These reports indicated a good level of independent performance evaluation of RP program implementation that included evaluation of station-wide TLD self-issuance and departmental representation at the exposure reduction committee meetings. The RP surveillances provided valuable program implementation feedback.

The radiological occurrence reports (RORs) for 1997 indicated low threshold for reporting with relatively few incidents reported. The incidents were determined to be of minor safety consequence and were thoroughly investigated with good emphasis on corrective actions (a previous weakness). The RORs generally required long periods for closure from several months to over a year.

RP program self-assessments for 1997 were reviewed. They consisted of quarterly planned assessments and a plethora of peer observations. Although both the planned assessments and the peer observations varied in quality from poor to excellent, in general, the RP self-assessment area has on average, improved with value added for RP program improvement.

c. Conclusions

The RP program oversight consisted of a combination of a good QA audit and surveillance program, effective radiological problem correction program, and RP self-assessment program that has begun to mature and provide meaningful input to the RP program. The licensee has a very good combination of program review processes in place to ensure quality RP performance is maintained.

P3 EP Procedures and Documentation (71750, 82301 & 92904)

P3.1 Loss of Emergency Notification System (ENS) One-Hour Report

a. Inspection Scope

The inspector followed up on the January 12, 1998 loss of the Control Room ENS, and resulting licensee one-hour report.

b. Observations and Findings

The licensee discovered on January 12, 1998, at about 10:00 p.m., that the Control Room ENS phone for Salem and Hope Creek was inoperable. The Salem Operations Superintendent (OS) made a common site one-hour report to the NRC at 11:53 p.m. in accordance with the Event Classification Guide (ECG), Section 11.7.1.b. The inspector questioned the timeliness of this report since 10 CFR 50.72(b)(1)(v) states that licensees shall report a major loss of communications capability (i.e., loss of ENS) as soon as practical, and in all cases within one hour.

The ECG states, in part, that a loss of the ENS for greater than one hour in the Control Room necessitates a one-hour report in accordance with Attachment 25. The attachment directs that the OS inform the NRC of the event within one hour, after the one-hour waiting period.

Licensee representatives stated that they used the guidance in NUREG-1022, Event Reporting Guidelines 10 CFR 50.72 and 50.73, as the basis for the one-hour waiting period. The first draft of revision 1, dated September 1991, states that a one-hour report should be made for a major loss of communications capability for other than a short period, i.e., less than one hour. Draft two of revision 1, dated February 1994, does not specify this short period exception for loss of ENS, but it does for other losses such as the alert sirens. It also states that the licensee should use engineering judgement in determining reportability. The licensee stated that based on the guidance available, its engineering judgement is that a loss for greater than one hour is a major loss of the ENS, and that the one-hour report will be made after that determination. A major factor in that judgement is the multiple redundant phone lines available in the event of an ENS failure (i.e., commercial telephone, dedicated telephone, microwave).

The inspector questioned the OS concerning the timeliness of the one-hour report after the one-hour waiting period had elapsed. He stated that he was busy talking with the load dispatcher and the NRC Operations Officer, as well as seeking support to correct the problem. The inspector concluded that since the NRC was aware of the loss before the report was made, the licensee had multiple redundant phone lines, and that the OS followed his procedure, that the one-hour report was sufficiently timely.

c. Conclusions

The licensee had a sound basis for the one-hour waiting period specified in the ECG before initiating a one-hour report. Since the NRC was aware of the ENS failure before the one-hour report was made, there were multiple redundant phone lines available while the ENS was inoperable, and the OS made the one-hour report within the time required by the ECG, the timeliness of the one-hour report was acceptable.

P4 Staff Knowledge and Performance in EP

a. Inspection Scope

On December 15, 1997, the licensee held an off-hours unannounced emergency call out drill. An Alert was declared at 7:47 p.m. and the Emergency Response Organization was notified by electronic pager at 7:57 p.m. The resident inspector and an emergency preparedness specialist observed the activities in the Control Room, Technical Support Center (TSC) and the Emergency Operations Facility (EOF) to evaluate the licensee's ability to respond to an off-hours emergency drill in a timely and professional manner.

b. Observations and Findings

In the TSC and EOF, all essential positions were filled within 60 to 65 minutes from the Alert declaration, meeting the licensee's goal. However, in the TSC there appeared to be some confusion between official activation and the turn over from the control room to the TSC. The licensee also identified this observation and plans to review this concern for resolution.

During the last NRC-observed unannounced call out drill in mid-1996, the licensee's response was very poor and the emergency response staff was not able to operate the facilities without excessive EP staff intervention. However, during this drill, the inspectors noted that command and control was very good, drillmanship was excellent, the engineering support group was proactive in performing real-time and "what if" assessments and the EP coaches provided very little guidance to the players.

c. Conclusions

In the past year, the licensee has made a concerted effort to improve their emergency drill response performance. This included conducting 12 drills, weekly table top workshops and four additional unannounced callout drills. The inspector concluded that the Emergency Preparedness staffs' dedication, training and management support of the program has lent to the significant improvements noted in this drill.

F8 Miscellaneous Fire Protection Issues (64150 & 92903)

F8.1 (Closed) NRC Technical Restart Issue II.27: Reactor Coolant Pump Oil Collection System (Unit 1)

a. Inspection Scope

As discussed in NRC IRs 94-33, 96-10, and 96-20, this issue remained open pending the completion for Unit 1 of design change package (DCP) 1EC-3437 to resolve reactor coolant pump (RCP) oil collection system hardware deficiencies and NRC walkdown of all four RCPs to verify the adequacy of the installed oil collection systems. The original design inadequacy of the oil collection systems was dispositioned as a non-cited violation in inspection report 96-20.

b. Observations and Findings

The inspector performed a walkdown of each of the four Unit 1 RCP oil collection systems and found that the changes designated by the design change had been appropriately implemented. The inspector determined that the installed configurations were well-designed to ensure that all potential leakage sites were protected and any oil would be collected and drained appropriately, as required by 10 CFR Part 50, Appendix R, section III.O.

The inspector reviewed the drawings and instructions established for personnel tasked with reassembly and inspection of the oil collection components and determined that such documentation clearly presented the requirements to verify the installed configuration met NRC requirements.

c. Conclusions

The inspector concluded that the licensee had improved the oil collection capabilities of the Unit 1 reactor coolant pump motors and provided reasonable assurance that a fire would not occur. The inspector verified that the installed oil collection system configurations met the NRC requirements. This restart issue is closed.

F8.2 (Closed) Unresolved Item 50-272/94-33-01:Reactor Coolant Pump Oil Collection System

Resolution of reactor coolant pump oil collection system deficiencies were originally reviewed in August 1996. At that time, the NRC found the program for addressing the identified deficiencies acceptable. As stated in IR 96-20 the NRC also found acceptable the changes that had been implemented previously for Unit 2.

As stated in Section F.8.1 of this report, the required Unit 1 modifications have now been completed and the NRC has found the installation of the plant changes acceptable. This item is closed.

F8.3 (Updated) EEI 50-272 & 311/97-257-03014: Post-fire Alternative Shutdown

a. Inspection Scope

This item is associated with Restart Issue III.a.1: Appendix R Safe Shutdown Concerns, which is discussed in section F8.8 of this report. The inspector reviewed the adequacy of the licensee's corrective actions taken to satisfy 10 CFR Part 50, Appendix R, section III.G and III.L requirements and to provide post-fire alternative shutdown system electrically independent and isolated from associated circuits in the fire area of concern so that hot shorts, shorts-to-ground, or open circuits would not prevent the operation of safe shutdown equipment. As documented in IRs 93-80 and 97-09 and in the licensee's response, dated May 19, 1997, the licensee's corrective actions were detailed regarding the installation of isolation transfer switches and rewiring of torque and limit switches for motor-operated valve control circuits to alleviate the above concerns. NRC review and acceptability of the licensee's corrective actions taken for Unit 2 and planned for Unit 1 were documented in IR 97-09, section F8.1.

Further, the acceptability of such corrective actions were discussed at an enforcement conference held on July 10, 1997. As documented in NRC letter dated October 8, 1997, enforcement discretion was exercised for PSE&G's failure to meet electrical independence requirements for the post-fire alternative shutdown system design. The scope of this inspection was to verify that the corrective

actions taken by the licensee to provide a post-fire alternative shutdown in Unit 1 were properly implemented.

b. Observations and Findings

The inspector reviewed design change package (DCP) 1EC-3486 that described the modifications to motor control centers and control panel circuits for providing electrical isolation and verified there were no differences in scope between Units 1 and 2. DCP 1EC-3486 modified the circuits for valves required for alternative shutdown as done in Unit 2 DCP 2EC-3546. The inspector noted that the assumptions made for multiple spurious operation of equipment had been incorporated into the Appendix R Safe Shutdown Analysis appropriately.

The inspector walked down selected motor control centers within the auxiliary building and verified field installation of the above modifications.

c. Conclusions

The inspector concluded that the licensee had properly completed the Unit 1 modifications for electrical independence and isolation and that the licensee's corrective actions were appropriate for providing reasonable assurance that alternative post-fire safe shutdown valves and components, needed to achieve and maintain hot shutdown, would perform their intended safety function.

This item will remain open for PSE&G's final resolution for the electrical raceway fire barrier system issue (see section F8.8 for acceptability for restart) and subsequent NRC review.

F8.4 (Closed) IFI 50-272 & 311/ 97-09-07: Appendix R Emergency Lighting

a. Inspection Scope

As discussed in NRC IR 97-09, this issue documented the discovery of loose emergency light lamp heads encountered during a plant tour and the appearance that such lights were improperly aimed for providing light to routes and equipment needed for fire safe shutdown. The licensee initiated action request (AR) 970416395 to resolve these concerns. The inspector reviewed the adequacy of the licensee's corrective actions to resolve this issue.

b. Observations and Findings

The inspector performed a walkdown throughout several plant areas within the auxiliary, control, and service buildings where plant operators would travel to equipment needed for safe shutdown of the plant. The inspector found that matching marks had been applied to the emergency light lamp heads allowing for ready visual verification of correct lamp head position. The inspector did not identify any unaimed or loose lamp heads and verified that the AR included corrective actions to revise the fire protection surveillance procedures to check the

position of the lights against the match marks. Additionally, the inspector determined that the licensee had not identified any improperly aimed emergency lights relied upon for fire safe shutdown.

c. Conclusions

The inspector concluded that the licensee had taken appropriate corrective action to ensure loose lamp heads were tightened and light is provided to routes and equipment needed for fire safe shutdown. This item is closed.

F8.5 (Closed) URI 50-272 & 311/97-09-02: Fire Door Hinges

a. Inspection Scope

As discussed in NRC IR 97-09, this issue documented the appearance of brass or bronze hinges being installed on fire doors. The licensee initiated AR 970416410 to further evaluate and resolve this issue. The inspector reviewed the adequacy of the licensee's actions to resolve this issue.

b. Observations and Findings

The licensee inspected all Salem Class 1 fire doors and hardware and determined that all but one fire door had the appropriate steel hinge material installed. Although fire door 112-2 hinge material was stamped "solid bronze," the licensee determined that this door was a non-Class 1 fire door used only for separation of the stairwell between the 84 foot elevation and 100 foot elevation within the Unit 2 auxiliary building and had no Appendix R function. The licensee appropriately replaced the hinge material for fire door 112-2 with steel material.

c. Conclusions

The inspector concluded that the use of a bronze hinge material on door 112-2 was an isolated event and the licensee's corrective actions were appropriate to ensure no other fire door deficiencies of this type existed that could affect the fire rating of the door assembly. This item is not a violation and is closed.

F8.6 (Closed) URI 50-272 & 311/97-09-03: Standpipe Hose Lengths

a. Inspection Scope

As discussed in NRC IR 97-09, the hydraulic adequacy of the fire protection system was questioned when additional hose lengths were needed for standpipe hose station 2-FP230, subsequently increasing friction and reducing the fire suppression system ability to develop design basis flows at its most remote location. The licensee initiated AR 970417429 to address this issue.

b. Observations and Findings

The licensee completed hydraulic analysis S-2-FP-MEE-1230, Revision 0, for standpipe 2-FP230 and determined that adequate pressure was available at the hose nozzle under conditions typical during fire fighting operations in the plant when connected to 150 feet of additional 1-1/2" fire hose. The inspector reviewed this analysis and determined that appropriate design input were used to calculate the resulting 140 psig of water pressure for fire fighting purposes.

c. Conclusions

The inspector concluded that the licensee appropriately analyzed the hydraulic adequacy of the standpipe in question with two additional hose lengths of 75 feet attached, if needed. This item is not a violation and is closed.

F8.7 Flow Control Valve Indication

a. Inspection Scope

As discussed in NRC IR 97-09, this issue documented the identification of fire protection deluge system pressure flow control valve 2FP301 indicating a pressure greater than the maximum suppression system design pressure. The licensee initiated AR 970416418 to address this minor discrepancy.

b. Observations and Findings

The licensee determined that this flow control valve pressure gauge indicated prime water pressure on top to the deluge valve clapper and not system pressure. This suppression system is primed when placed in service and then the priming line is closed with system pressure being measured downstream of this flow control valve. The licensee removed 2FP301 from service and found that the gauge was properly calibrated and hydrostatically tested to a pressure twice that of system design pressure.

c. Conclusions

The inspector concluded that the flow control valve in question was properly sized and calibrated for its installed use.

F8.8 (Closed) NRC Programmatic Restart Issue III.a.1: Appendix R Safe Shutdown Analysis (Unit 1)

a. Inspection Scope

As discussed in NRC IRs 93-80 and 97-09, several 10 CFR Part 50, Appendix R concerns were identified as addressed in this report, sections F8.1 through F8.7. In addition to these concerns, the NRC performed a follow-up of the compensatory measures implemented while the fire resistive capabilities remain indeterminate for electrical raceway fire barrier systems (ERFBS). The licensee committed to maintain

such compensatory measures as identified in their Cable Raceway Fire Wrap Resolution Plan, as described in their letters to the NRC dated May 19, 1997 and June 6, 1997. The scope of this inspection was to verify that such compensatory measures remained in effect and provided adequate monitoring of assigned plant locations.

b. Observations and Findings

The inspector toured Unit 1 plant areas containing ERFBS and interviewed fire department fire watches utilized as compensatory measures to rove these areas on an hourly basis. The inspector determined that fire watches were knowledgeable of their responsibilities to monitor such areas for any changes that could increase the likelihood of a fire and to inform the control room of any fire symptoms or fire that may occur.

The inspector reviewed several completed logs for firewatch patrols associated with ERFBS and did not identify any discrepancies where any roving patrols were missed. The inspector reviewed records for May through December 1997.

c. Conclusions

The inspector concluded that compensatory measure fire watches were knowledgeable of their duties and provided effective monitoring of assigned Unit 1 plant locations containing ERFBS. The inspector noted that in PSE&G's letter to the NRC, dated June 6, 1997, the licensee committed to provide periodic updates on the progress of their Cable Raceway Fire Wrap Resolution Plan. Based on the corrective actions taken by the licensee to resolve Appendix R concerns, as discussed in report sections F8.1 through F8.7, including the maintenance of compensatory measures pending completion of the Fire Wrap Resolution Plan, this restart item regarding Unit 1's Appendix R Safe Shutdown Analysis is closed.

F8.9 (Open) IFI 50-272 & 311/97-09-01: Penetration Seals

a. Inspection Scope

As discussed in NRC IR 97-09, the thermal mass of the items that penetrate as-built penetration seals and the maximum free area of unsupported penetration seal material installed could not be readily determined for each penetration. Although the inspectors believed the as-built drawings were bound by the tested configurations for the seals, this could not be verified because the as-built drawings did not identify cable size and cable fill for each penetration. The inspector reviewed the licensee's actions to evaluate the thermal impact of a large mass on penetration seal performance.

b. Observations and Findings

The inspector found that the licensee's review was not complete. The licensee had reviewed approximately 12,200 penetration seals and identified approximately

1000 seals that required additional review and analysis to verify that they were bound by the tested configurations.

At the time of this inspection, the licensee was considering performing a generic bounding test using a 300 MCM size cable and was reviewing test results completed for Watts Bar Nuclear Power Plant. The inspector did not identify any additional concerns that would have changed the previous interpretation that the as-built drawings were bound by the tested configurations for the seals.

c. Conclusions

The inspector determined that the licensee needed further review and analysis to verify the as-built drawings were bound by the tested configurations for penetration seals. However, the inspector judged that the thermal impact of masses penetrating seals would not reduce the effectiveness of the seals to an unacceptable level of performance. This item remains open pending NRC review and acceptance of the licensee's comparison and analysis results that the thermal mass of as-built penetration seals is less than the thermal mass of tested configurations or that seal performance would not be degraded if the thermal mass of the installed penetrations was greater.

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 February 9, 1998. The licensee acknowledged the findings presented and did not indicate that any proprietary information was identified.

X2 INPO Report Review

During this report period, the inspector reviewed the INPO Report for the evaluation conducted in November 1997. The results were generally consistent with the most recent NRC assessment of the licensee's performance. No additional regional follow-up inspection is planned.

X3 Pre-Decisional Enforcement Conference Summary

On December 9, 1997, two pre-decisional enforcement conferences were held at the NRC Region I office. The first was held to discuss an apparent violation of 10 CFR 50.7 (employee Protection) for discrimination against a security officer for her involvement in raising security concerns. The second was held to discuss an apparent violation of 10 CFR 50.9 (completeness and accuracy of information) for false documentation that compensatory measures were implemented within the required time by security personnel. Overheads used in the licensee's presentation at this meeting have been included as Attachment 1 to this report.

X4 Management Meeting Summary

On December 4, 1997, a meeting was held between the management of PSE&G and NRC Region I and the Office of Nuclear Reactor Regulation (NRR), at the Salem Units 1 & 2 Nuclear Generating Station. The purpose of the meeting was to review the lessons learned during the restart of Salem Unit 2 and to discuss how these lessons learned have been and will be applied to the Salem Unit 1 restart. The meeting was held to satisfy the remaining Confirmatory Action Letter (CAL) 1-95-009 requirement for Salem Unit 2. Overheads used in the licensee's presentation at this meeting have been included as Attachment 2 to this report.

INSPECTION PROCEDURES USED

IP 37550:	Engineering
IP 37551:	Onsite Engineering
IP 40500:	Effectiveness of Licensee Controls in Identifying, Resolving, and Preventing Problems
IP 50001:	Steam Generator Replacement Inspection
IP 60710:	Refueling Activities
IP 61726:	Surveillance Observations
IP 62707:	Maintenance Observations
IP 71707:	Plant Operations
IP 71750:	Plant Support Activities
IP 82301:	Evaluation of Exercises for Power Reactors
IP 83750:	Occupational Radiation Exposure
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

Opened

50-311/97-21-01	VIO	Failure to comply with procedures for configuration control
50-272 & 311/97-21-03	IFI	Guidelines for instrument loop design loading
50-272 & 311/97-21-04	VIO	Inadequate evaluation of VOTES test result
50-311/97-21-05	VIO	Failure to include a containment penetration breaker in the TS-required surveillance program.

Opened/Closed

50-272/97-21-02	NCV	Failure to meet time requirements for reporting a violation of minor significance
50-272/97-21-06	NCV	Inadequate test of certain safety injection and service water check valves
50-272/97-21-07	NCV	Radiation monitor 1R11A deficiencies.
50-272/97-21-08	NCV	Pressure locking thermal binding valve deficiencies
50-272&311/97-21-09	VIO	Lack of power range neutron detector environmental qualification
50-272&311/97-21-10	NCV	Adequacy of TDAFP enclosures
50-272&311/97-21-11	NCV	CFCUs outside plant design basis
50-272 & 311/97-21-12	NCV	Inadequate pressurizer heater cable separation
50-272 & 311/97-21-13	NCV	28 Vdc battery capacity exceeded

Closed

50-272/90-81-13	URI	Cable Separation
50-272/93-19-03	URI	2R15 Radiation Monitor System Inoperability
50-272/93-21-02	URI	Containment Isolation - 1R11A Radiation Monitor Alarms.
50-272/93-26-01	URI	Evaluation of Pressure Locking and Thermal Binding of Gate Valves
50-272 & 311/94-04-01	URI	Power Range Neutron Detectors
50-272/94-33-01	URI	Reactor Coolant Pump Oil Collection System
50-272/95-17-04	URI	Adequacy of EDG Loading Margin.
50-272 & 311/96-01-09	URI	CR205 Relay Application in Safety Related Applications.
50-272 & 311/96-13-03	URI	EDG Load Fluctuations
50-272 & 311/96-16-03	URI	Followup of Fuse-Related Discrepancies
50-311/96-18-04	IFI	Main condenser steam dumps malfunction
50-272/97-02-02	VIO	Failure to Test MCCBs in Instantaneous Region
50-272 & 311/97-05-01	VIO	Inadequate Implementation of 10 CFR 50.59 requirements
50-272&311/97-08-02	IFI	Control air system reliability
50-272&311/97-09-02	URI	Fire door hinges
50-272&311/97-09-03	URI	Standpipe hose lengths
50-272&311/97-09-07	IFI	Appendix R emergency lighting
50-272 & 311/97-16-02	URI	Cable Separation Within Panels and Cabinets
50-272/95-012	LER	Adequacy of turbine driven auxiliary feed water pump enclosures
50-272/95-023-01	LER	Failure to plug steam generator tubes due to missed eddy current indications
50-272/96-020	LER	CFCUs outside plant design basis
50-272/96-030	LER	Alignment of Back-Up Pressurizer Heaters for Emergency Power Does Not Meet Separation Criteria.
50-272/96-036	LER	28 Vdc Battery Capacity Exceeded
50-272/97-004	LER	Inadequate Surveillance Testing of Molded case Circuit Breakers.
50-311/97-010-01	LER	TS required shutdown due to position indication system anomalies
50-311/97-017	LER	Failure to comply with Technical Specification for Unit 2 Chiller

Discussed

50-272&311/97-09-01	IFI	Penetration seals
50-272&311/97-257-03014	VIO	Post-fire alternative shutdown

LIST OF ACRONYMS USED

ABV	Auxiliary Building Ventilation
AFP	Auxiliary Feed Pump
AFW	Auxiliary Feedwater
ALARA	As Low As Reasonably Achievable
AR	Action Request
CAL	Confirmation Action Letter
CAV	Control Area Ventilation
CCW	Component Cooling Water
CFCUs	Containment Fan Coil Units
CM	Corrective Maintenance
CP	Charging Pump
CR	Condition Report
CVCS	Chemical and Volume Control System
DCP	Design Change Package
DCRs	Design Change Requests
ECCS	Emergency Core Cooling System
ECG	Event Classification Guide
EDG	Emergency Diesel Generator
EDSFI	Electrical Distribution System Functional Inspection
EMI/RFI	Electromagnetic/Radio Frequency Interference
ENS	Emergency Notification System
EOF	Emergency Operations Facility
EOPs	Emergency Operating Procedures
ERFBS	Electrical Raceway Fire Barrier Systems
ESF	Engineered Safety Feature
GL	Generic Letter
HELB	High Energy Line Break
HEPA	High Efficiency Particulate Air
IFI	Inspector Followup Item
IPAT	Integrated Performance Assessment Team
IR	Inspection Report
ISI	Inservice Inspection
IST	Inservice Test
IVD	Individual Vendor Documents
LER	Licensee Event Report
LOCA	Loss of Coolant Accident
LP	Low Pressure
mA	Milliamperes
MANTG	Mid-Atlantic Nuclear Training Group
MCRs	Modification Change Requests
MOV	Motor Operated Valve
MPC	Maximum permissible concentration
NIS	Nuclear Instrumentation System
NRC	Nuclear Regulatory Commission
NRR	Nuclear Reactor Regulation
NVLAP	National Voluntary Laboratory Accreditation Program

OHA	Overhead Annunciator
OS	Operations Superintendent
PC	Penetration Cooling
PDP	Positive Displacement Pump
PDR	Public Document Room
PI	Performance Indicator
PIRs	Performance Improvement Requests
PORV	Power Operated Relief Valve
PSE&G	Public Service Electric and Gas
QA	Quality Assurance
RATI	Readiness Assessment Team Inspection
RCP	Reactor Coolant Pump
RCS	Reactor Coolant System
RG	Regulatory Guide
RHR	Residual Heat Removal
RMS	Radiation Monitoring System
ROR	Radiological Occurrence Report
RP	Radiation Protection
RP&C	Radiological Protection and Chemistry
RWST	Refueling Water Storage Tank
SAC	Station Air Compressor
SER	Safety Evaluation Report
SG	Steam Generator
SI	Safety Injection
SORC	Station Operations Review Committee
SPT	Station Power Transformer
SRO	Senior Reactor Operator
SRRB	System Readiness Review Board
SS	Stainless Steel
SSPS	Solid State Protection System
SW	Service Water
TCF	Torque Correction Factor
TDAFP	Turbine Drive Auxiliary Feed Pump
TLD	Thermoluminescent dosimeter
TRIS	Tagging Request and Inquiry System
TS	Technical Specification
TSAS	Technical Specification Action Statement
TSC	Technical Support Center
TSR	Thrust Switch Repeatability
UFSAR	Updated Final Safety Analysis Report
VDG	Vendor Document Group
VEG	Vendor Engineering Group
VOTES	Valve Operation Test and Evaluation System
WO	Work Order

PSE&G

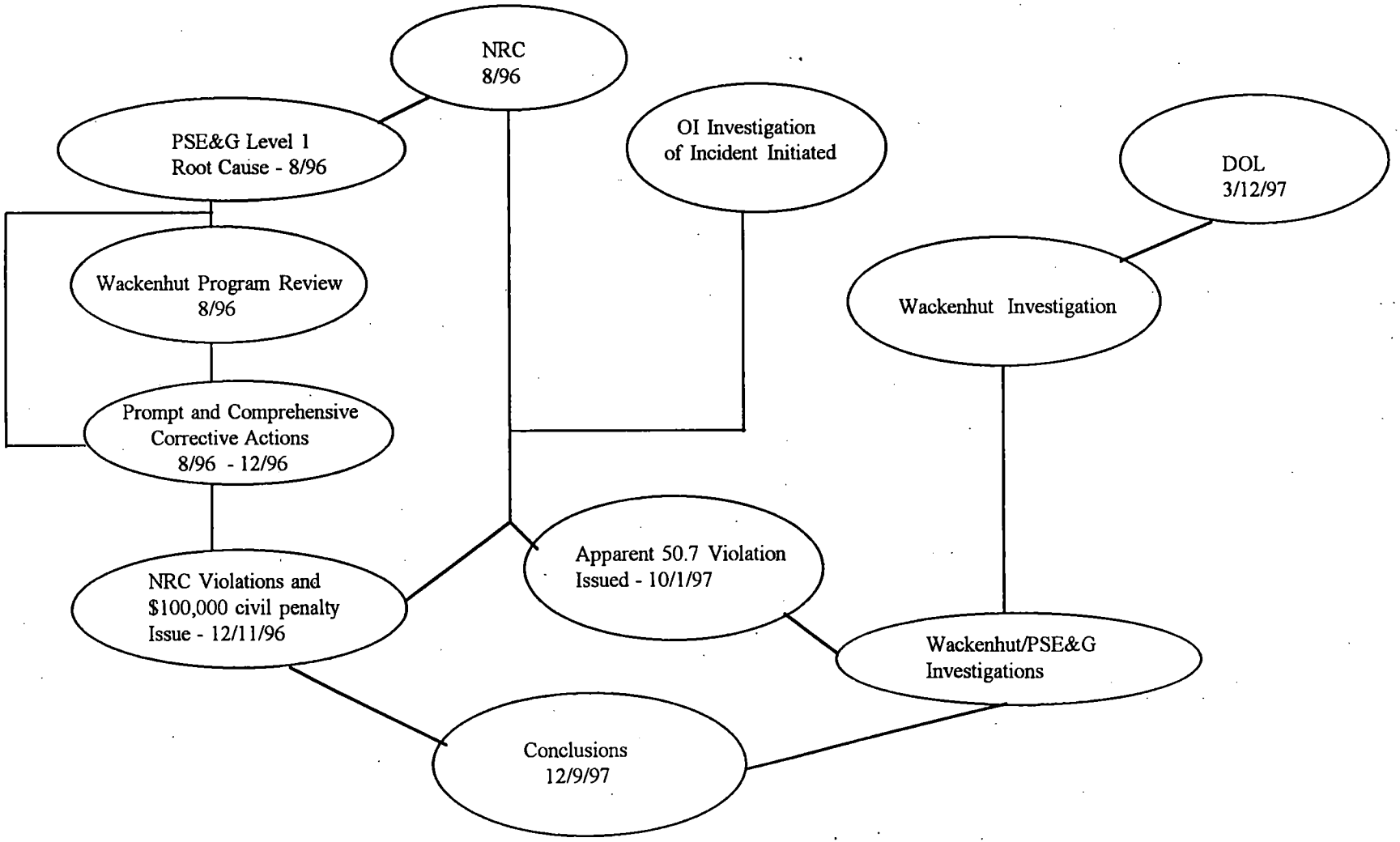
PREDECISIONAL ENFORCEMENT CONFERENCE NRC INVESTIGATION 1-96-031

DECEMBER 9, 1997

AGENDA

- Opening Comments
- Apparent Violation
- Background
- Timeline
- Comprehensive Corrective Actions
- Conclusions
- Summary

INTERACTIONS



APPARENT VIOLATION

- Discrimination against a Security Officer for raising safety concerns

ELEMENTS OF 50.7

- Employee
- Engaged in Protected Activity
- Adverse employment action
- 10CFR50.7(d), allows employment action for legitimate reasons

BACKGROUND

- Historic SALP 1 Rating
- June 5, 1996 - Crawl test not performed
- Aug 1996 Self-Revealing Security Events
- Conducted investigations
- 6 violations and a $100,000 civil penalty involving security

Failed security leadership resulted in a cultural decline.

TIMELINE

Supervisor Involved Stated Test was not Needed-Supervisor Later Fired	6/5	Crawl Test initially not performed
Due to Poor Leadership/Communications & Inconsistent Discipline Officers Raised Issues to Union	[Shortly After Event]	Issue Raised to Union by Officers Involved
Manager took the Issue no Further. Manager Later Determined to be Major Part of Cultural Issues & was Released		Issue Raised to Wackenhut Site Manager
Union's Large Number of Grievances (~119)Senses of Frustration Lead to Notification of NRC to Resolve		Union Raises Issue to NRC
A Number of Self-revealing Issues Being Investigated by Wackenhut & PSE&G	8/19	During Wackenhut Investigation of another Issue, Crawl Test Situation Raised
Issue Raised as Part of Cultural Discussions	8/21	Officer Interviewed by Wackenhut Investigation Team (NRC not present)
In accordance with Wackenhut practices a recommendation to Suspend Pending Investigation was made	8/21	Wackenhut Investigators Recommend Suspension
Supervisor Suspends Officer. Question as to Use of NRC Within Discussion	8/22	Officer Receives Suspension Pending Investigation
Same practice applied to others in similar situation	8/23	Other Officers Involved Receive Same Treatment
	8/26	Officers Receive Back Pay & Made Whole (Wages & Expunged Records)
		Supervisor Involved Released for this & Other Issues

COMPREHENSIVE CORRECTIVE ACTIONS

- Conducted investigations
- Suspended Security Officers
- Replaced Management
- Returned security officers to duty

Prompt, Comprehensive, Effective Corrective Actions resulted in an improved culture.

CONCLUSIONS

- Decision made by Wackenhut management to suspend 16 security officers
- Security officers returned to duty, made whole, and records were removed from files
- Suspension was appropriate and consistent

CONCLUSIONS

- No 50.7 violation
  - Security Officer did not talk to NRC prior to being suspended
  - Program Manager and Supervisor likely knew issue had been taken to NRC
  - Supervisor likely mentioned NRC
  - Involved Security Officers suspended until investigation was complete due to questions about reliability and trustworthiness

SUMMARY

- Management Changed Out
- New Supervision
- New Processes
- Employee Concerns Program Communicated
- Corrective Action Program Communicated
- Security Officers Made Whole
- Improved Communications

Corrective Actions implemented prior to and independent of knowledge of allegation (Aug. 1996).

PSE&G

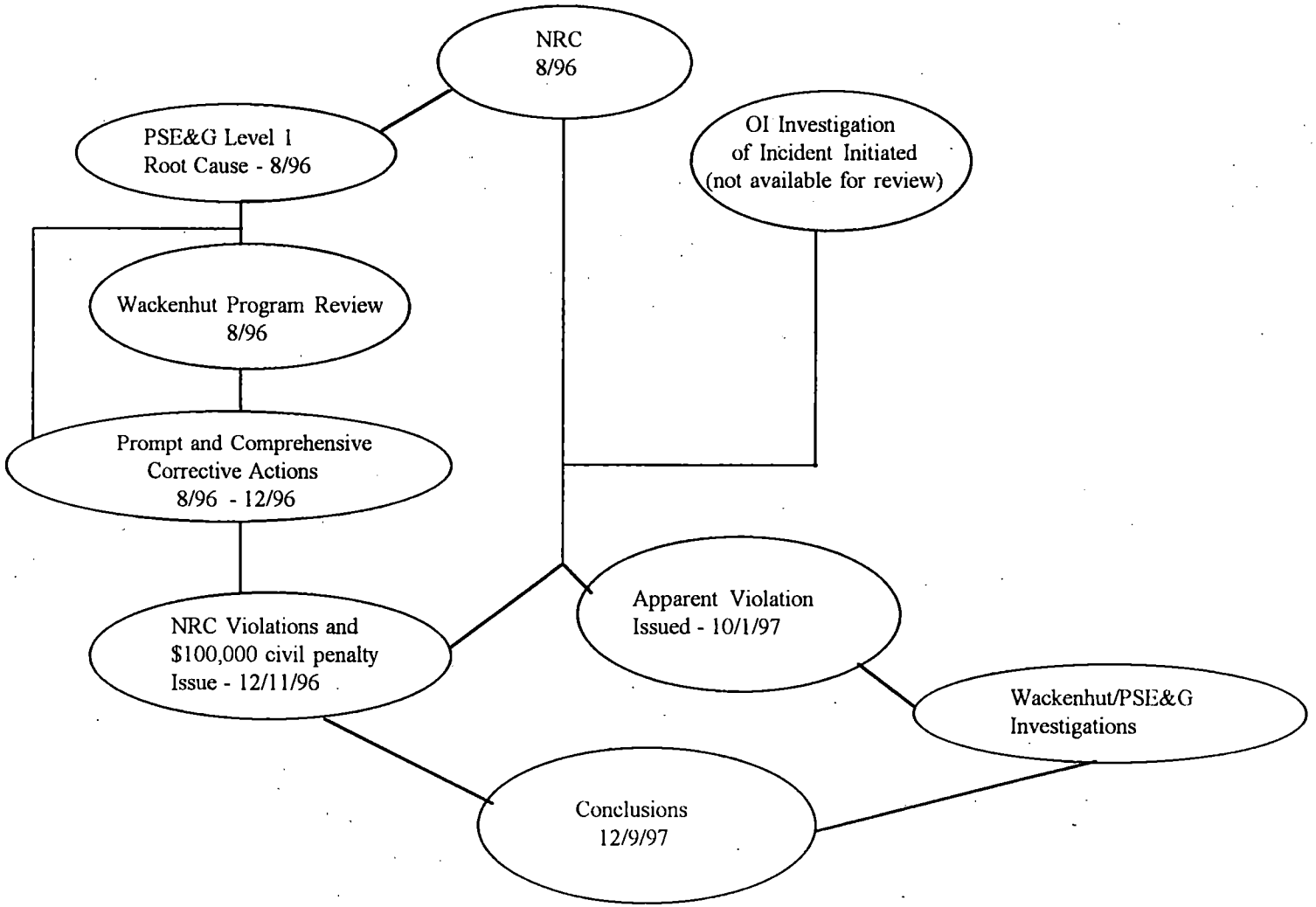
PREDECISIONAL ENFORCEMENT CONFERENCE NRC INVESTIGATION 1-96-024

DECEMBER 9, 1997

AGENDA

- Opening Comments
- Apparent Violation
- Background
- Timeline
- Corrective Actions
- Reportability
- Conclusions

INTERACTIONS



APPARENT VIOLATION

- Inaccurate information regarding the posting of compensatory measures was recorded in the Safeguards Event Log.
- The deliberate actions of two Wackenhut personnel caused this documentation inaccuracy.

BACKGROUND

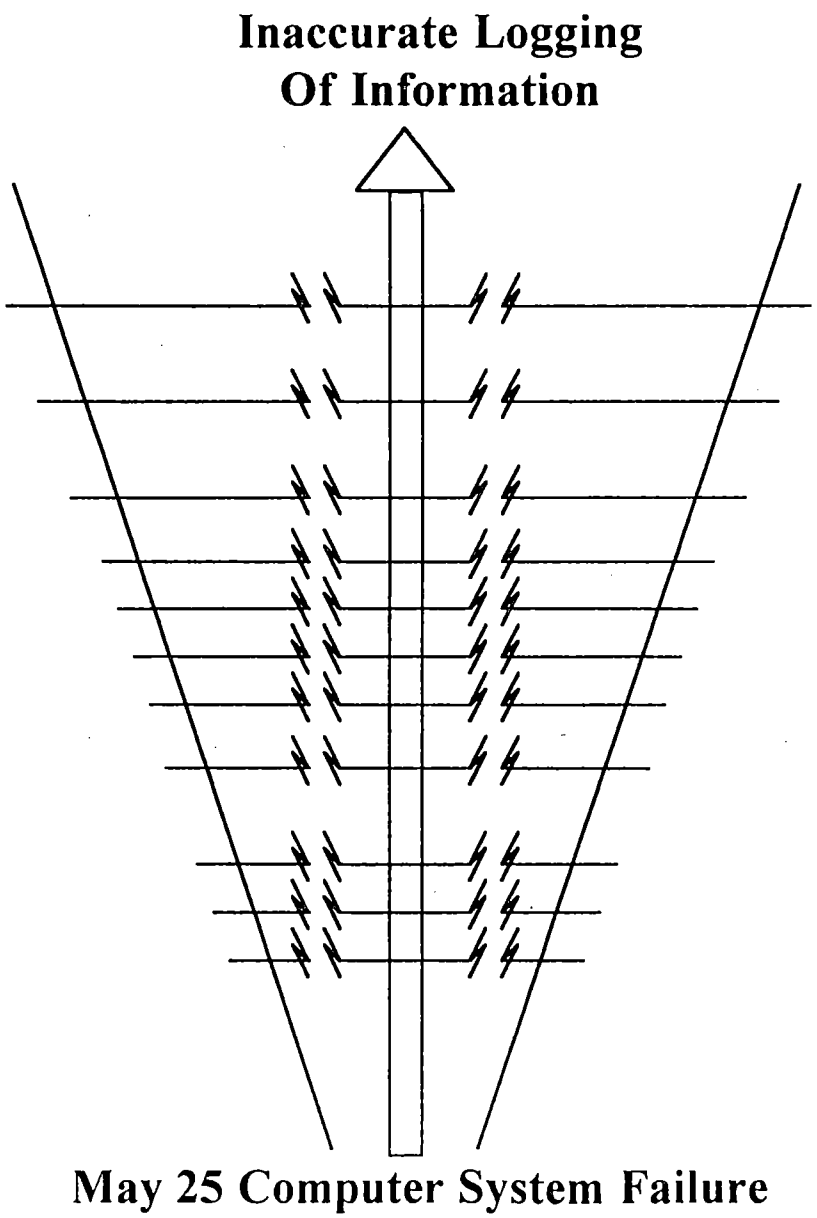
- Historic SALP 1 Rating
- May 25, 1996 - Computer crashed during shift turnover
- Aug 1996 Self-Revealing Security Events
- Conducted investigations
- 6 violations and a $100,000 civil penalty involving security

Failed Security Leadership resulted in a cultural decline.

TIMELINE

Compensatory Post not Manned in Time	**5/25**	Security Computer Crash
Due to Poor Leadership/Communications & Inconsistent Discipline Officers Raised Issues to Union	**[Shortly After Event]**	Issue Raised to Union by Officers Involved
Manager took the Issue no Further. Manager Later Determined to be Major Part of Cultural Issues & was Released		Issue Raised to Wackenhut Site Manager
Union's Large Number of Grievances (~119)Senses of Frustration Lead to Notification of NRC to Resolve		Union Raises Issue to NRC
A Number of Self-revealing Issues Being Investigated by Wackenhut & PSE&G	**8/19**	Wackenhut Investigation of Security Issues
List of accumulated issues provided by union and Security Officer	**8/22**	Wackenhut Team Identified Computer Crash Issue
Investigation Determines That Post not Manned as Required	**8/23**	Investigation conducted after information was brought forward
		Event Logged Based on Investigation Conclusions

CONTRIBUTING FACTORS



- Ineffective Post Event Critique
- Strained Communications Between Officers and Supervisors
- Focus on Processing Personnel
- Central Alarm Station Operator pre-occupied
- Security Operations Supervisor not familiar with computer restoration
- New Supervisors (first computer system failure)
- New Access Operations Supervisor (first day on job)
- Concurrent Hope Creek event requiring compensatory posting*
- Extra Comp Post at Salem Service Water*
- Use of Overtime
- Posts Call into more than one Location
- Logging Time Via Scrap Paper
- Shift Turnover
- Computer Failure

* = New finding in recent investigation

COMPREHENSIVE CORRECTIVE ACTIONS

- Management Changed Out
- New Supervision
- New Processes
- Employee Concerns Program Communicated
- Corrective Action Program Communicated
- Security Officers Made Whole
- Improved Communications

Corrective Actions implemented prior to and independent of knowledge of allegation (Aug. 1996).

SPECIFIC CORRECTIVE ACTIONS

- Computer system failure was logged
- Late compensatory post was logged when discovered
- Investigated potential computer tampering
- Investigation revealed no basis to conclude computer related cover-up

Computer tampering not likely.

REPORTABILITY

- Computer system failure was a loggable event, and was logged.
- Failure to meet compensatory posts within 10 minutes is a loggable event, and was subsequently logged (Aug 23, 1996)
- Failure to meet compensatory posts is loggable per SCP-15, Safeguards Event Reporting and GL 91-03, Reporting of Safeguards Events

REPORTABILITY

- No malevolent intent for computer failure
- No breach of vital areas
- No unauthorized entry into Protected Area
- Appropriate measures were taken to improve compensatory posting process
- Criterion for logging this event were met

Event determined not to be reportable

CONCLUSIONS

- Inaccurate information logged (10CFR50.9)
- Investigations did not substantiate or eliminate collusion
- Aug 1996 - Previous investigation effective
- Aug 1996 - Leadership change out effective
- Culture improved
- Improved Security Officer behaviors

CONCLUSIONS

- Prompt, comprehensive, effective corrective actions were taken
- Lessons were learned and communicated

Salem Unit 2
Lessons Learned Meeting

The Power of Commitment
PSEG

PUBLIC SERVICE ELECTRIC & GAS

SALEM UNIT 1

DECEMBER 4, 1997

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PSEG

INTRODUCTION

LEON R. ELIASON
President & Chief Nuclear Officer

Introduction

The Power of Commitment
PSEG

- Safe Operation
- Reliable Operation
- Eventless Operation

Agenda

The Power of Commitment
PSEG

• Restart Journey Learnings	L. Storz
• Lessons Learned - Unit 2 Restart	C. Bakken G. Nagy
• Independent Oversight	C. Fricker
• Unit 1 Restart Progress	J. Benjamin
• Management Focus	
– Training	J. Mc Mahon
– Maintenance	M. Trum
– Engineering	D. Garchow
• Next Steps	E. Simpson

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PSEG

RESTART JOURNEY

LOU STORZ

Salem Unit 2
Restart Journey

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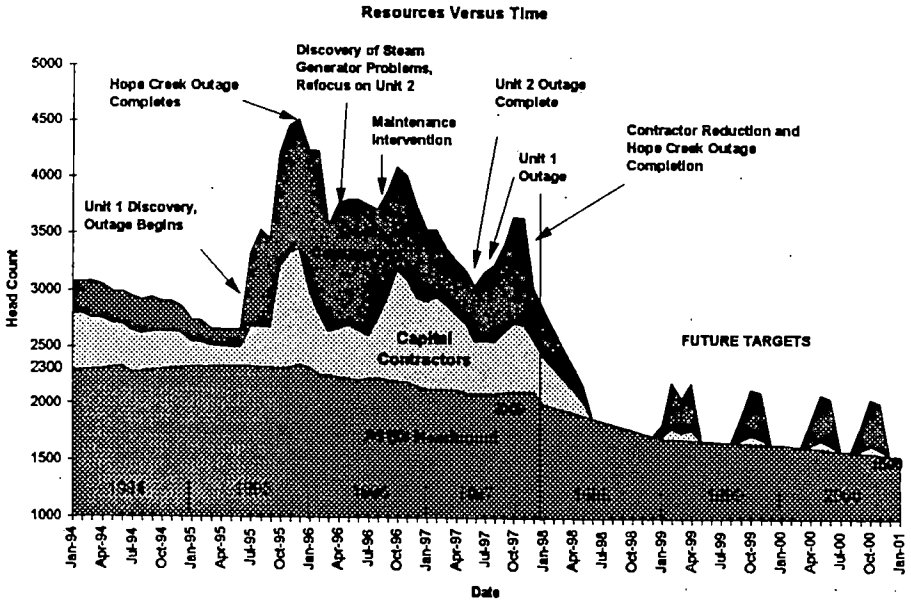
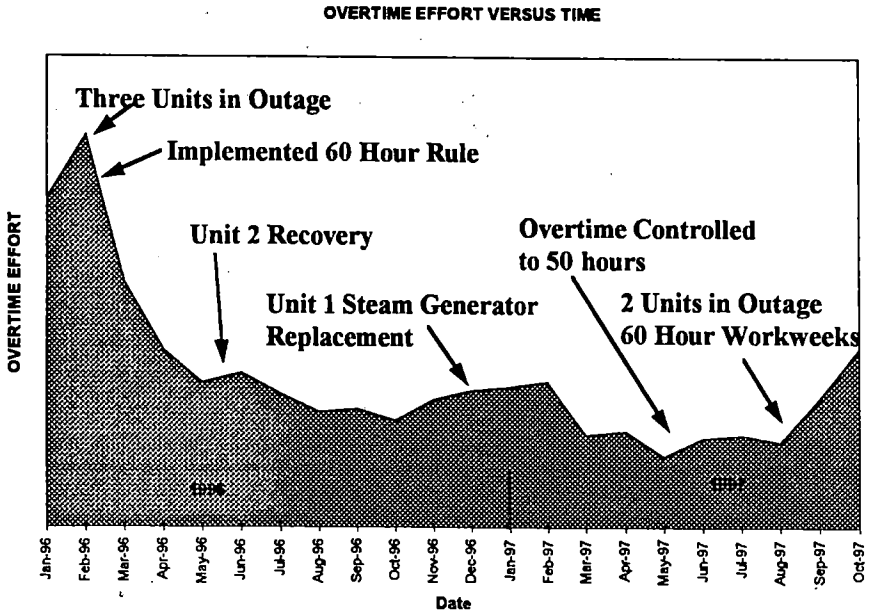
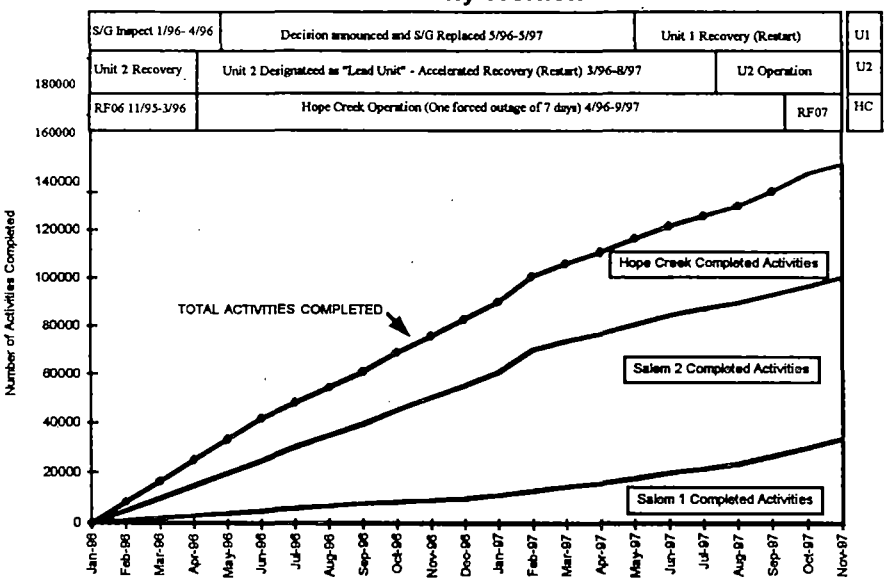
PSEG

- Level of Effort to Restart
- Matching Resources to Workload
- Future Organization


Resources Versus Time
Hope Creek Outage Completes
Discovery of Steam Generator Problems, Refocus on Unit 2
Unit 2 Outage Complete
Maintenance Intervention
Contractor Reduction and Hope Creek Outage Completion
Unit 1 Outage
Unit 1 Discovery, Outage Begins
Capital Contractors
FUTURE TARGETS
Head Count
Date


OVERTIME EFFORT VERSUS TIME
Three Units in Outage
Implemented 60 Hour Rule
Unit 2 Recovery
Overtime Controlled to 50 hours
Unit 1 Steam Generator Replacement
2 Units in Outage 60 Hour Workweeks
OVERTIME EFFORT
Date

Activity Workoff



*Data prior to 6/96 is best information available

Future Organizational Configuration

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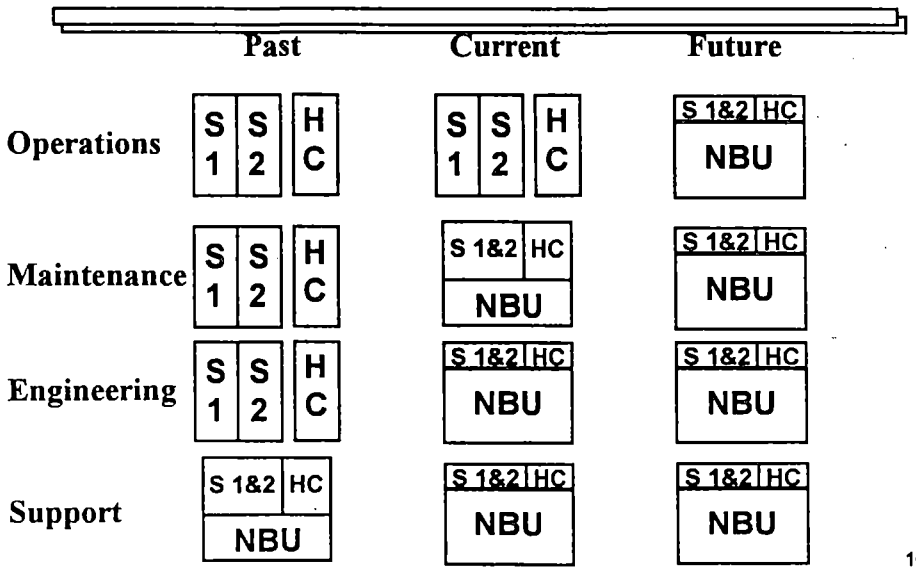
PSEG



Summary
What We Learned

The Power of Commitment
PSEG

- **EXPERIENCED MANAGEMENT** (New Leadership / Fresh Ideas)
- **CORRECTIVE ACTION PROGRAM** (Find & Fix Problems, Monitoring / Trending, Affirmations, Independent Oversight, Self Assessments, Employee Concerns)
- **HIGH STANDARDS** (Expectations Set by Senior Management)
- **CHANGE HUMAN PERFORMANCE / CULTURE** (Fundamentally, Existing Employees Can Make the Change)
- **EFFECTIVE TRAINING** (Intervention When Necessary)

Summary
What We Learned

The Power of Commitment
PSEG

- **SOUND PLANNING** (Simple Restart Plan Developed by the Organization)
- **WORK THE INTEGRATED PLAN**
- **BE FLEXIBLE** (Open-mindedness, Confront Problems, Adjust)
- **OPERATE IN THE DESIRED STATE** (Operations Led)
- **UTILIZE DIVERSE INPUT** (Employees, Independent, Regulatory, Industry)

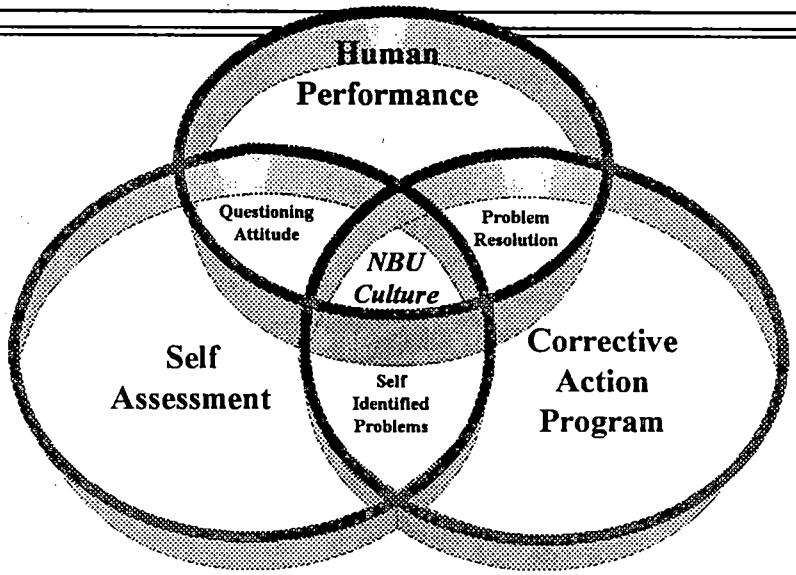
The Power of Commitment
PSEG

STARTUP LESSONS LEARNED

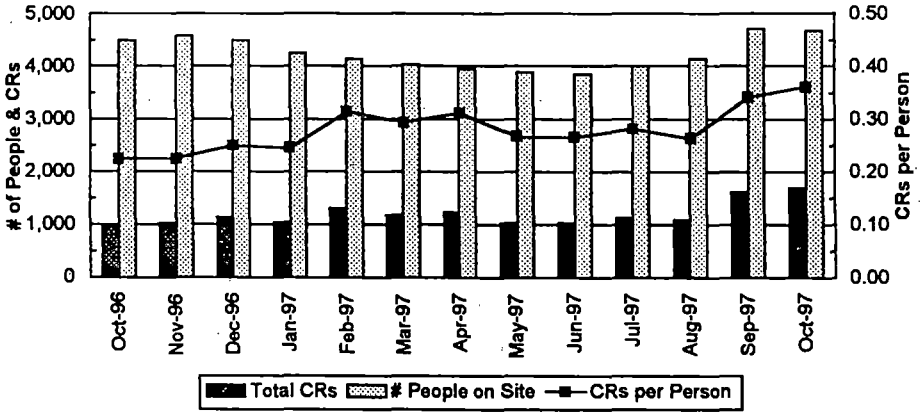
CHRIS BAKKEN / GENE NAGY

Culture Change

The Power of Commitment
PSEG



Condition Reports vs People



Culture Change

The Power of Commitment
PSEG

- Defining and Communicating Expectations
- Higher Standards Established
- Personnel Performance Measurements
- Corrective Action and Self Assessment Resulting in Performance Improvements

Resulted In Eventless Startup

Startup Testing Program

The Power of Commitment
PSEG

- Event Free Startup
  - Management Oversight
  - Operations Led
  - Effective Pre-job Briefings
  - Sequence Document

Thoroughly Tested Unit 2

Startup Testing Program

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PSEG

- Challenges
  - Control Room Ventilation
  - Rod Control System
  - Heater Drain Systems
  - Steam Generator Feed Pumps
  - Pressurizer Level Transmitter

The Startup Team Met Challenges with Success

Plant Hardware Issues

The Power of Commitment
PSEG

- Eight Focus Systems Were Identified
  - Feedwater & Condensate System
  - Main Steam System
  - Reactor Control and Protection System
  - Chemical and Volume Control System
  - Diesel Generator System
  - Service Water System
  - Reactor Coolant System

These Eight Systems Caused 45 of 54 Forced Outages Since 1988 (83%)

Results

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PSEG

- Successfully Completed 147 Integrated Tests & Thousands of Component Tests
  - Digital Feedwater System
  - Station Air Compressors
  - Primary and Secondary Plant Tuning
  - Reactor Coolant System Excess Cooldown
  - Service and Circulating Water

We Worked the Plan Effectively

Results

The Power of Commitment
PSEG

- Management Oversight
- Power Ascension Self Assessments
- Critical Review by Quality Assurance, Institute of Nuclear Power Operations and Nuclear Regulatory Commission

Lessons Learned During Unit 2 Startup

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- Operations Senior Reactor Operator assigned to Startup
- Just-in-Time Training, Simulator Validated
- Contingency Plans and Sponsors

Items Identified and Corrected

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NRC Issues - Test Preparation

- Correct Test Deficiencies
- Independent Review of Remaining Testing
- Evaluate Testing Methods

Items Identified and Corrected

The Power of Commitment
PSEG

NRC Issues - Test Implementation

- Site Test Program Philosophy
- Retrain and Recertify Test Engineers
- Management Expectations
- Test Review Board

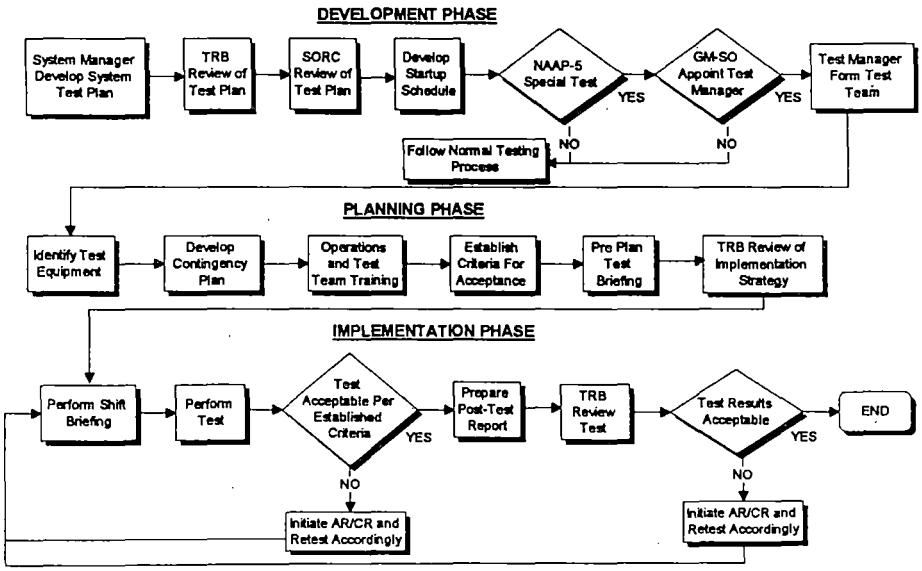
Startup Testing Program

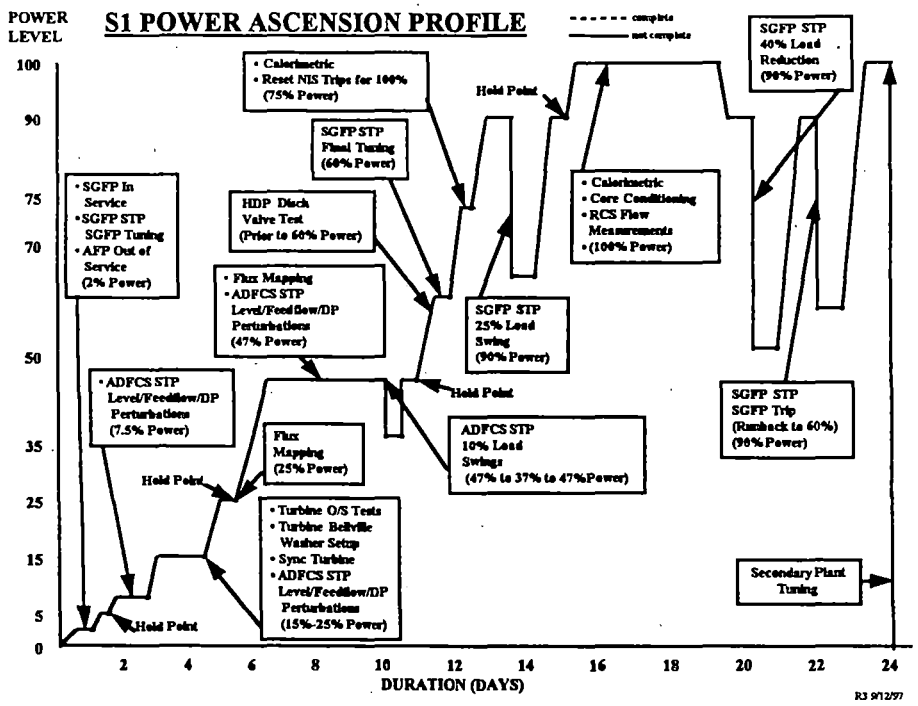
The Power of Commitment
PSEG

- Unit 1 Startup Program
  - Same Comprehensive and Rigorous Testing as Unit 2
  - Added Steam Generator Testing
- Implement Lessons Learned

STARTUP AND POWER ASCENSION PROGRA

SPECIAL TEST PREPARATION AND PLANNING FLOW CHART





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INDEPENDENT ASSESSMENT

CARL FRICKER

Independent Oversight

The Power of Commitment
PSEG

- Restructured Quality Assurance
- Built an Effective Employee Concerns Program
- Sponsored Corrective Action Program

Independent Oversight

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PSEG

- New People, New Expectations, Innovative Assessment Techniques
- Effected Change in Key Areas
- Focused Assessment Strategy for Salem Restart

Independent Oversight

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- Continue to Focus Management Attention on Weak Areas
- Continue to Get Qualified Personnel With Line Experience

Continue Hard-Hitting, Intrusive, and Effective Independent Oversight

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PSEG

UNIT I RESTART PROGRESS

JEFF BENJAMIN

Unit 1 Restart Status

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PSEG

- Current Status
- Restart Schedule
- NRC Programmatic & Technical Issues

First Quarter 1998 Startup

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PSEG

TRAINING

JERRY Mc MAHON

Training

The Power of Commitment
PSEG

- Assessments and Interventions
- Consistent Re-qualification Training
- Continue Infusion of New, Trained People

Training

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PSEG

- Common Accredited Training Programs
- Vendor Training in 1998
- Complete Intervention in 1998
- Specialty Equipment Training

Right People, Right Skills
Right Place

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MAINTENANCE ACTIVITIES

MARTY TRUM

NBU Maintenance

The Power of Commitment
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- One Site Philosophy
- Human Performance
- Future Plans

One Site Philosophy

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- Lessons Learned on Unit 2 Applied to Unit 1
- One Team Performing All Work on Unit 1
- Common Procedures Group
- Common Corrective Action Group
- Specialized Teams
- Common Maintenance Workforce

Human Performance

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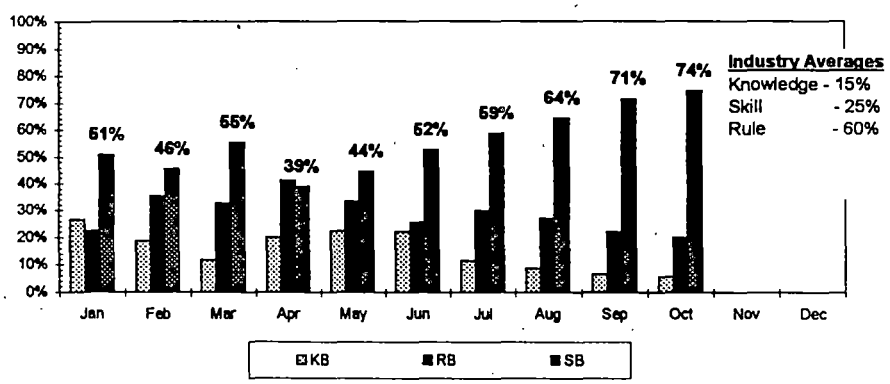
PSEG

- Personnel Error Trend
- Skill Based Errors
- Standardized Personnel Performance Files & Expectations
- Supervisory Field Presence

Salem Maintenance Error Types



- Knowledge Based
- Rule Based
- Skill Based

Human Performance

The Power of Commitment
PSEG

- Personnel Error Trend
- Skill Based Errors
- Standardized Personnel Performance Files & Expectations
- Supervisory Field Presence

Future

The Power of Commitment
PSEG

- Increased Accountability & Supervisory Field Presence
- Maintenance Engineering
- Resource Sharing With PECO
- Outage Planning Group
- Focus on Maintenance Planning
- Mutual Gains With IBEW to Remove Barriers

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PSEG

ENGINEERING

DAVE GARCHOW

Engineering Improvement Strategy

The Power of Commitment
PSEG

Right Work *done by the*

Right Engineers *at the*

Right Time

Right Work

The Power of Commitment
PSEG

- Resolve Plant Issues
- Backlog Reduction
- Fire Protection and Design Bases
- System Monitoring and Trending
- On-line and Outage Planning
- Continual Self Assessment
- Right Modifications

Right People

The Power of Commitment
PSEG

Organization of Future
Defined for NBU Technical Support

- Maintenance Engineering Transferred to Maintenance
- NBU System, Design, Licensing, and Fuels Organization
- Limited Contractor Support
- Zero-Based to Match Skills to Positions
- Process Created Open Positions
- Filling Open Positions with Right Skills

Right Time

The Power of Commitment
PSEG

- Engineering Work Management System
- Accountability for Planning Milestones
- Improved Tools for Maintenance Support
- System Performance Monitoring and Trending - Input to On-line Maintenance

Shifting From Recovery to Operational Organization

The Power of Commitment
PSEG

NEXT STEPS

BERT SIMPSON

Next Steps

The Power of Commitment
PSEG

- Safe / Reliable Operation
- Eventless Startup of Unit 1
- Backlog Reduction
- Refueling Outage Planning
- Achieve Excellent Three Unit Operation

Safely Generate Competitive Electricity with Nuclear Power

CLOSING

LEON ELIASON

The Power of Commitment
PSE&G