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 50-272/98-09, 50-311/98-09

This integrated inspection included aspects of licensee operations, engineering, maintenance, and plant support. The report covers a six-week period of resident inspection; in addition, it includes the results of announced inspections by several NRC region-based inspectors. These inspections included reviews of the work management program, system engineering, and the corrective action program.

Operations

Observed operator performance was generally good. The decision to isolate the Unit 1 and 2 positive displacement pumps during an evaluation of emergency core cooling system leakage outside containment was conservative. The detection of the No. 23 steam generator tube leak showed good attention to detail, and PSE&G's actions in response to the leak were reasonable. (Section O1.1)

The main coolant system leak air particulate monitor was not functional for about five days, which was not known by PSE&G personnel. Although the monitor is not safety-related, this event demonstrated weak control of important to safety equipment status. (Section O2.1)

The Station Operations Review Committee continued to provide effective oversight of Salem operations and the Corrective Action Review Board appropriately challenged the quality of corrective actions for previously identified issues. There was a need to provide expectations to board presenters to ensure all necessary information was available for discussion. (Section O7.1)

Inadequate procedure guidance resulted in the inadvertent actuation of engineered safety features equipment during surveillance testing. PSE&G's corrective actions to address this event were adequate. (Section O8.3)

Operator misinterpretation of procedural guidance resulted in an inoperable control room emergency air conditioning system train. PSE&G's immediate and planned corrective actions for this event were adequate. (Section O8.4)

Maintenance

Inspectors noted several weaknesses in preventive maintenance activities performed on the 13 auxiliary feedwater (AFW) pump. PSE&G documented these issues in action requests and immediate corrective actions were adequate. The 13 AFW pump surveillance test was adequate to test pump discharge pressure, and showed satisfactory results. (Section M1.2)

The 1A1 125 volt DC battery charger was found to be inoperable due to an incorrect setting of the high voltage shutdown relay, resulting in an unplanned entry into a seven-day technical specification action statement. The other two Unit 1 chargers and one Unit

2 charger were also set incorrectly. This event was self-revealing, but had no safety consequence, and corrective actions were adequate. (Section M1.3)

The multiple leak repairs performed on feedwater containment isolation valve 12BF22 demonstrated poor planning and communications between departments, and weak management oversight. Additionally, overall communication with the NRC was weak considering the relative importance of the valve. (Section M2.1)

PSE&G implemented reasonable corrective actions for a self-revealing event involving a failure by maintenance technicians to restore the 22 auxiliary feed water pump discharge pressure transmitter to service following a calibration. However, largely because of the repetitive nature of this issue, this failure resulted in a violation of technical specification 6.8.1 for failure to implement procedures. (Section M4.1)

The inspectors found that the backlog of outstanding corrective maintenance activities remained high and no significant improvement had been made in reducing it. The inspectors concluded that the program has been slowly evolving and required additional management oversight to ensure improvement. Performance indicators were useful and the Salem Planning and Scheduling department had established an effective self-assessment program. (Section M8.1)

Engineering

The Salem system engineering staff included a nucleus of knowledgeable system engineers with several years of nuclear experience. System experience was limited at times, but engineers indicated strong willingness to seek guidance from more experienced personnel. Individual system training was acceptable. The system performance review meetings were good management tools to evaluate individual knowledge of the systems and to impart integrated insights on the systems. (Section E2.1)

Current system engineering procedures contained sufficient guidance for the proper implementation of the system engineering monitoring program. System engineers continued to operate partly in a reactive mode, despite the establishment of a maintenance engineering group. However, clear areas of responsibility had been established and the system engineers were assuming system responsibility. Also, a system engineering master plan was underway to further strengthen the role of the system engineer and to better manage work activities. Communications with maintenance engineering and operations were good. (Section E2.1)

The licensee continued to experience reliability and availability problems with radiation monitors at both Salem Units. However, appropriate steps were being taken to address the instrument failures. The root cause analysis multi-disciplinary team showed good understanding of the issues involved. Good management support of the effort was also evident. (Section E2.2)

The licensee's response to a question associated with the potential for age-related seal failures of CO_2 valves was weak. The licensee was slow in addressing this issue, which was first identified at Hope Creek in September 1997. When the licensee confirmed the

applicability of this failure to Salem, the licensee did not assure that the CO_2 valves would perform as designed. Subsequent to NRC questioning, the licensee developed an analysis that provided the bases for assuring that the valves would perform as designed. The licensee indicated that steps had been initiated to expedite replacement and examination of additional valves during the next work week window. Although this action appeared reasonable, this issue was left unresolved pending NRC review of the results of the licensee's examination of these valves. (Section E2.3)

Although established emergency diesel generator (EDG) reliability monitoring program guidance was not actively employed, PSE&G personnel were adequately monitoring EDG reliability under the requirements of 10 CFR 50.65. PSE&G established appropriate performance criteria to ensure that EDG reliability commitments were maintained. (Section E2.4)

Within the scope of the inspection, the inspectors found that the licensee appropriately utilized the condition resolution and business process subsystems for resolution of sampled issues. Although the disposition of action requests selected for review did not identify any improperly categorized findings, the inspectors remained concerned that problems could be mischaracterized and bypass needed operability reviews. However, PSE&G had initiated efforts to correct the self-identified misapplications within the action request system. Improved management oversight of the corrective action program was evident. Engineering self-assessments and quality assurance reviews provided valuable insights. (Section E7.1)

PSE&G was actively engaged in the resolution of concerns raised by the NRC regarding spent fuel pool cooling design and decay heat load management, and has implemented a reasonable approach to completing these activities prior to the next core off-load. (Section E8.1)

Plant Support

Due to recent organizational changes, chemistry department personnel did not process a revision to the offsite dose calculation manual in accordance with station procedural guidance. The inspectors concluded that PSE&G personnel applied an appropriate level of technical and management review to process the revision, and implemented adequate corrective actions for the identified procedural non-compliances. (Section R8.1)

PSE&G's emergency operations facility and Salem's technical support center were properly maintained. All necessary emergency equipment and procedures were adequately controlled. (Section P2.1)

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Report Details

Summary of Plant Status

Unit 1 began the period at 100% power. On September 19, 1998, PSE&G reduced power to 90% to perform maintenance on No. 13 heater drain pump. The unit was returned to 100% power later that day. On September 22, power was reduced to 25% to perform maintenance on the 12 steam generator feed pump and 12 control rod drive motor fan, and also to investigate oil level alarms on the 12 and 14 reactor coolant pumps. The unit was returned to 100% power on September 24. On September 25, power was reduced to 65% to repair an oil leak on the 12 steam generator feed pump. The unit was restored to full power on September 26 and remained at that power level until the end of the period.

Unit 2 began the period at 100% power and remained at that power level until the end of the report period.

I. Operations

O1 Conduct of Operations

O1.1 General Comments

a. Inspection Scope (71707)

The inspectors conducted frequent observations of ongoing plant operations, including control room walkdowns, log reviews, and shift turnovers. The inspectors also conducted numerous plant tours to observe equipment operation and nuclear operators working in the field.

b. Observations and Findings

In general, the conduct of operations was professional and safety-conscious. The Unit 1 downpower evolutions for No. 13 heater drain pump and No. 12 steam generator feed pump maintenance were performed in a safe and controlled manner. Operators followed approved procedures, were knowledgeable of evolutions concerning plant status changes, and demonstrated excellent communications.

On September 15, 1998, PSE&G took the Unit 1 and 2 positive displacement charging pumps (Nos. 13 and 23) out of service and isolated the pumps while evaluating the design basis limits for emergency core cooling system leakage outside containment during cold leg recirculation. The packing leakage from these pumps may result in exceeding the leakage limit, and thus exceed the General Design Criteria (GDC) 19 doses to control room operators during a design basis accident. The decision to isolate the pumps during the evaluation was conservative.

On September 29, 1998, PSE&G detected a trend of increased gross radioactivity in No. 23 steam generator. A more detailed sample analysis revealed radioactive

particles which indicated a primary to secondary leak. The leak rate calculation was initially about one gallon per day (GPD), which is well below the technical specification limit of 500 GPD, and barely detectable in a sample. For this reason, the detection of the leak was a good observation by the chemistry technician who observed the trend. The leak gradually increased to about two gallons per day, and remained at that level for the rest of the inspection period. PSE&G appropriately increased the sampling frequency and monitoring of No. 23 steam generator, and heightened operator sensitivity to the issue. Additionally, on October 13, 1998, PSE&G management briefed NRC management concerning the leak.

c. Conclusions

Observed operator performance was generally good. The decision to isolate the Unit 1 and 2 positive displacement pumps during an evaluation of emergency core cooling system leakage outside containment was conservative. The detection of No. 23 steam generator tube leak showed good attention to detail, and PSE&G's actions in response to the leak were reasonable.

O2 Operational Status of Facilities and Equipment

O2.1 Main Coolant System Leak Air Particulate Monitor Found In Off-Normal Position

a. Inspection Scope (92901, 92903)

The inspectors reviewed PSE&G's actions following identification that the Unit 2 main coolant system leak air particulate monitor (MCSLPM) was found in an off-normal condition, with the air pump turned off.

b. Observations and Findings

On October 5, 1998, PSE&G radiation protection personnel found the Unit 2 MCSLPM air pump not running while investigating an upward trend on the 2R11A containment radiation (air particulate) monitor. The MCSLPM is a reactor head leak detection radiation monitoring system used to detect reactor head leaks when compared with the R11A readings. The monitor is not safety-related, but is contained in the Configuration Baseline Document for the radiation monitoring system, and PSE&G committed to its operation for reactor head area leak detection.

The MCSLPM is powered from a containment lighting panel and controlled by three light switches. Two switches are located in containment and a third is on panel 2RP3 in the control room. Operation of any of these switches will de-energize the MCSLPM. The switch in the control room has an operator aid which cautions that it powers MCSLPM and should not be turned off. It does not say that the monitor air pump must be reset locally if turned off. PSE&G was unable to determine the cause of this event but concluded from an inspection of the paper strip recorder that the air pump was off for about five days.

The inspectors concluded that this event demonstrated weak control of the MCSLPM monitor status. Radiation protection personnel log MCSLPM readings every four hours, but a normal baseline reading is barely distinguishable from a reading with the air pump de-energized. PSE&G intended to improve the operator aids at the three controlling light switches to inform operators that the MCSLPM air pump must be reset locally if it is de-energized. The inspectors concluded that unless power interruption to the monitor was prevented, it may not be available when needed, since the air pump can only be restarted locally in the containment. An actual leak causing an increase on the R11A monitor would preclude a containment entry.

c. Conclusions

The main coolant system leak air particulate monitor was not functional for about five days, which was not known by PSE&G personnel. Although the monitor is not safety-related, this event demonstrated weak control of important to safety equipment status.

O6 Operations Organization and Administration

O6.1 Operator Overtime

a. Inspection Scope (71707)

The inspectors reviewed PSE&G's operator overtime records to verify compliance with established maximum overtime limits. The inspectors referenced guidance from plant technical specifications (TS) and procedure NC.NA-AP.ZZ-0005 (NAP-5), *"Station Operating Practices."*

b. Observations and Findings

NAP-5 contained operator overtime guidelines based on NRC Generic Letter 82-12, *"Nuclear Power Plant Staff Working Hours."* The inspectors reviewed overtime records for September and October 1998, and noted that the operator overtime usage was below NAP-5 limits. No instances of excessive individual overtime use were noted, and monthly management reviews of overtime practices were performed as required by NAP-5.

c. Conclusions

PSE&G maintained adequate administrative controls for the use of operator overtime. Salem operations department personnel properly implemented the established controls, preventing the excessive use of operator overtime.

O7 Quality Assurance in Operations

O7.1 Oversight of Salem Operations

a. Inspection Scope (71707)

The inspectors attended Station Operations Review Committee (SORC) and Corrective Action Review Board (CARB) meetings to assess their effectiveness concerning the oversight of Salem operations. Minutes of meetings not attended were also reviewed.

b. Observations and Findings

The inspectors attended two SORC and two CARB meetings during the report period. A quorum of PSE&G personnel was present at each meeting and they were prepared to discuss the topics on the meeting agenda. Board members were appropriately critical of the presentations and focused the conversation on safety issues. For example, concerning the issue of clogged service water strainers, CARB members questioned why it took six months to present the issue, and determined that the process from root cause determination to a corrective action effectiveness review must be more clearly defined. The inspectors concluded that, based on the questions posed to the presenters, there was a need to communicate expectations to the presenters to ensure that they have all necessary information available for discussion. The inspectors noted that PSE&G had previously initiated efforts to address this concern and subsequently promulgated new guidance for these meetings.

c. Conclusions

The Station Operations Review Committee continued to provide effective oversight of Salem operations and the Corrective Action Review Board appropriately challenged the quality of corrective actions for previously identified issues. There was a need to provide expectations to board presenters to ensure all necessary information was available for discussion.

O8 Miscellaneous Operations Issue

O8.1 (Closed) LER 50-311/98-001-00:Failure to Meet Technical Specification (TS) 3.3.3.7 Table 3.3-11 Item 19 - RVLIS

a. Inspection Scope (92901)

This Licensee Event Report (LER) documented that with test instrumentation connected to the reactor vessel level instrumentation system (RVLIS) panel for Unit 2, the channel separation criteria was violated and RVLIS was inoperable. The test instrumentation provided inadequate isolation between the non-safety related data acquisition system (DAS) and the RVLIS channels. This condition had existed on Unit 2 while the Unit was in Mode 3, during the period July 5 to August 6, 1997.

The condition was identified on January 27, 1998 during evaluation of the installation of similar test instrumentation for the Unit 1 RVLIS. Based on the results of the evaluation, the instrumentation was not installed on Unit 1.

b. Observation and Findings

The inspector performed an in-office review of this LER based on the minimal safety significance of the issue. RVLIS provides the operators with indication of core inventory and thus assists in detecting the onset of inadequate core cooling. However, other systems and parameters were available such as the core exit thermocouples, reactor coolant outlet temperature and subcooling margin monitors, all of which are TS-required. In addition, the emergency operating procedures provide direction for restoration of core cooling with and without RVLIS.

The inspector reviewed the licensee's root cause evaluation and corrective actions and found them to be appropriate. This licensee-identified and corrected violation of TS 3.3.3.7 for RVLIS is being treated as a Non-Cited Violation, consistent with Section VII.B.1 of the NRC Enforcement Policy. **(NCV 50-311/98-09-01)**.

c. Conclusions

The licensee took appropriate corrective action in response to a reactor vessel level instrumentation system channel separation issue. This LER is closed.

O8.2 (Closed) LER 50-272/98-008-00: Inadequate Testing of the Salem Unit 1 Containment Air Locks Resulted in Entering Technical Specification (TS) 3.0.3

a. Inspection Scope (92901)

This LER was written to document a condition in which the Unit 1 containment air locks were not being properly tested. The Schrader valve that controls the air supply to the exterior door was not working properly which meant that no air was being supplied to the exterior door seal during the performance of the leak rate test.

b. Observations and Findings

The inspector performed an in-office review of the LER based on the minimal safety significance of the issue. Specifically, when the Schrader valve was repaired and the leak rate test re-performed on the exterior door seal, the results were satisfactory. Therefore, the overall airlock leak rate at design pressure had been satisfactory at all times.

The inspector reviewed the licensee's root cause and corrective actions and found them acceptable. This failure to meet the surveillance requirements of TS 4.6.1.3.a is considered a violation of minor significance.

c. Conclusions

The licensee took appropriate corrective actions in response to identifying inadequate testing of the Unit 1 containment air locks. This LER is closed.

O8.3 (Closed) LER 50-311/98-011-00: Engineered Safety Features Actuation During a 4KV Automatic Transfer Test

a. Inspection Scope (92700, 92901)

The inspectors performed an onsite review of the nature, the corrective actions, and the root cause of the event described in the subject LER.

b. Observations and Findings

On August 3, 1998, during surveillance testing, the 2A 4KV vital bus failed to automatically transfer its power supply between the associated station power transformers (SPT). As a result, the 2A bus deenergized, causing the safeguards equipment cabinet to generate an undervoltage equipment start signal. All affected engineered safety features (ESF) equipment functioned as designed. PSE&G personnel determined the cause of the event to be the premature release of the SPT control console push-button by the control room operator trainee. The existing procedural guidance failed to warn the operators that the pushbutton must be depressed and held until the expected indications are received. The inspectors verified that PSE&G personnel revised the associated surveillance test procedures to include the necessary guidance. At the time of the event, unit 2 was in cold shutdown. The event did not adversely impact the shutdown cooling lineup. Therefore, the event had minimal safety implications. The failure to have adequate procedural guidance is considered a violation of minor significance.

c. Conclusions

Inadequate procedural guidance resulted in the inadvertent actuation of engineered safety features equipment during surveillance testing. PSE&G's corrective actions to address this event were adequate.

O8.4 (Closed) LER 50-272/98-013-00: Operation with Technical Specification Equipment Out of Service

a. Inspection Scope (92700, 92901)

The inspectors performed an onsite review of the nature, the corrective actions, and the root cause of the event described in the subject LER.

b. Observations and Findings

On August 6, 1998, during testing of the control room intake radiation monitors, common control room emergency air conditioning system (CREACS) damper 2CAA17 failed to open as expected. PSE&G personnel determined that the damper had been incorrectly pinned closed during control area ventilation (CAV) "maintenance mode" operation three days earlier, and that the error had not been identified during subsequent CAV restoration to "normal mode" operation. Equipment operators were incorrectly directed to pin damper 2CAA17 closed, due to misinterpretation of guidance contained in procedure S1(2).OP-SO.CAV-0001, *"Control Area Ventilation Operation."* Operation with 2CAA17 pinned closed rendered the unit 2 CREACS train inoperable. PSE&G personnel determined that damper 2CAA17 was pinned closed for approximately forty hours. In this condition, TS 3.7.6 requires that the CREACS be aligned for single train operation within four hours. Under certain accident conditions with 2CAA17 pinned closed, control room operator doses could potentially exceed regulatory limits. However, the redundant CREACS train remained operable throughout the event, minimizing any potential consequences.

The inspectors verified completion of selected corrective actions, which included additional CAV system training for licensed operators, and the development of a team to evaluate programmatic deficiencies pertaining to the restoration of safety-related systems. Other planned corrective actions include CAV system training for non-licensed equipment operators and revisions to procedure S1(2).OP-SO.CAV-0001 to clarify the manipulation of the noted damper during "maintenance mode" operation. This failure to align the CREACS for single train operation is a violation of TS 3.7.6. 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 50-272/98-09-02)**

c. Conclusions

Operator misinterpretation of procedural guidance resulted in an inoperable control room emergency air conditioning system train. PSE&G's immediate and planned corrective actions for this event were adequate.

II. Maintenance

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

M1.1 General Comments

The inspectors observed all or portions of the following maintenance and surveillance activities.

Unit 1

• WO 980622138	Repair 12 SGFP gib key
• WO 980922100	Replace 1A 125 VDC battery cell terminal fasteners
• WO 980929090	Trip temperature bistables, loop 13
• WO 980813068	Enter loop 12 statepoint data
• SC.CH-SA.CBV-0243	Unit 1 containment air particulate detector sample
• S1.OP-ST.AF-0002	12 AFW pump surveillance test
• S1.RE-ST.ZZ-0001	Calorimetric calculation
• S1.OP-PT.TRB-0001	Main turbine testing
• S1.IC-CC.RCP-0009	Loop 13 channel calibration
• S1.MD-FT.4KV-0002	1B 4KV vital bus undervoltage test

Unit 2

• WO 020302010	Molded case circuit breaker overcurrent testing
• S2.IC-FT.RM-0018	2R13A functional test
• S2.IC-FT.RM-0072	2R44A functional test
• S2.OP-ST.DG-0001	2A EDG surveillance test

The inspectors observed that the plant staff performed the maintenance activities within the requirements of the station maintenance program, and that the plant staff properly performed surveillance testing, effectively proving operability of the associated systems. The inspectors performed a detailed review of two instrument and controls surveillances due to recent weaknesses in this area, with no problems noted.

M1.2 Preventive Maintenance and Inservice Testing of 13 Auxiliary Feedwater Pump

a. Inspection Scope (62707)

The inspectors observed various preventive maintenance items (PMs) being performed on the 13 auxiliary feedwater (AFW) pump, and reviewed associated documentation and the data for the subsequent surveillance run of the pump.

b. Observations and Findings

The inspectors noted that the replacement filter for the turbine oil change was mistakenly staged to the Hope Creek storeroom instead of Salem, which caused a minor work delay. Additionally, the post-maintenance test (PMT) following completion of the PMs did not assure that all air was vented from the governor oil, resulting in speed oscillations during the surveillance run. In addition, the turbine trip valve failed to fully close when the pump was manually tripped from the control room.

PSE&G initiated action requests for these issues and immediate corrective actions were adequate. Management intended to evaluate the appropriateness of the PMT conducted after a governor oil change and make any necessary changes.

Management also intended to review the frequency of routine PMs to ensure that they are performed to maximize system reliability and availability. The inspectors determined that these actions were reasonable.

The inspectors reviewed the completed surveillance documentation and determined that the 13 AFW pump met the acceptance criteria, and that the test met the intent of the technical specifications for testing pump discharge pressure. The inspector questioned the decision to run the pump several times to vent the governor oil, and then proceed directly into the surveillance run, from the standpoint of potential equipment pre-conditioning. The inspector noted that surveillance tests should test the as-found condition of equipment for trending purposes, and that preventive maintenance should not be routinely scheduled before these tests. PSE&G management stated they are mindful of the pre-conditioning issue, and would evaluate their surveillance scheduling process for potential pre-conditioning.

c. Conclusions

Inspectors noted several weaknesses in preventive maintenance activities performed on the 13 auxiliary feedwater (AFW) pump. PSE&G documented these issues in action requests and immediate corrective actions were adequate. The 13 AFW pump surveillance test was adequate to test pump discharge pressure, and provided satisfactory results.

M1.3 Inoperability of 1A1 125 Volt DC (VDC) Battery Charger

a. Inspection Scope (62707, 92902)

The inspectors followed up on the trip of 1A1 125 VDC battery charger AC input breaker when PSE&G personnel placed the 1A battery on equalize charge. This event resulted in an unplanned entry into a seven-day technical specification action statement for an inoperable battery charger.

b. Observations and Findings

On September 28, 1998, PSE&G personnel attempted to place 1A 125 VDC battery on equalize charge. A short time later, the AC input breaker to 1A1 125 VDC battery charger tripped, which aborted the battery charge operation. A second attempt to establish the charge resulted in an identical breaker trip. Operators correctly declared the battery charger inoperable, placed 1A2 battery charger in service, and entered technical specification 3.8.2.3.b, which allows operation on the backup battery charger for seven days.

Initial trouble-shooting revealed that 1A1 high voltage shutdown (HVSD) relay was set low incorrectly (139.7 V. instead of the required 144-146 V.). This relay functions to trip the AC supply breaker on a high voltage condition. The 1B1 and 1C1 as-found setpoints were 141 V. and 146.2 V. respectfully, also out of tolerance. One Unit 2 charger was out of tolerance as well (2A1 was 146.3 V.). PSE&G corrected these setpoints and returned the 1A1 battery charger to service.

Further investigation revealed that all Unit 1 and 2 battery chargers were replaced by a design change in 1997, which was the last time the 18-month surveillance was performed to check the HVSD relay setpoint. The battery chargers were either set wrong after the design change installation or drifted out of tolerance sometime thereafter. PSE&G personnel identified that the surveillance procedure referred to the wrong potentiometer in the step for the HVSD relay adjustment. Also, the HVSD potentiometer is very sensitive and must be adjusted over a period of time instead of making a one time adjustment. This was not clear in the procedural guidance. PSE&G intended to make procedure changes to correct these issues.

The failure of the 1A1 125 VDC battery charger was self-revealing, in that it failed during an equalizer battery charge and was not discovered during a surveillance test. This resulted in an unplanned entry into a seven-day limiting condition of operation. Three other battery chargers were also inoperable due to incorrect setpoints on the HVSD relays. However, inspectors concluded that this event had no safety consequence since no DC battery voltage was affected, and that the corrective actions were adequate. For these reasons, the event constituted a violation of minor significance which is not subject to formal enforcement action.

c. Conclusions

The 1A1 125 volt DC battery charger was found to be inoperable due to an incorrect setting of the high voltage shutdown relay, resulting in an unplanned entry into a seven-day technical specification action statement. The other two Unit 1 chargers and one Unit 2 charger were also set incorrectly. This event was self-revealing, but had no safety consequence, and corrective actions were adequate.

M2 Maintenance and Material Condition of Facilities and Equipment

M2.1 Leak Repair of Feedwater Containment Isolation Valve 12BF22

a. Inspection Scope (62707, 92902)

The inspectors reviewed documentation for leak repair activities performed on the 12BF22 valve, and observed portions of the leak repair performed on October 23, 1998. The inspectors also interviewed engineering, maintenance, and operations personnel concerning these repairs.

b. Observations and Findings

The 12BF22 valve is one of four motor-operated stop check valves which function as feedwater containment isolation valves. The valve is a 14 inch pressure seal bonnet globe valve and is safety-related, nuclear class 2 and seismic class 1. The motor operator ensures positive closure to meet GDC 57 requirements in the event of an accident.

PSE&G first identified an unisolable pressure seal leak on the valve on May 18, 1998. Multiple leak repairs were performed on the valve by injecting leak sealant into injection ports which were drilled into the valve body. The first repair was performed on June 12, 1998, using X36 A&B sealant in two injection ports. This repair was effective for about 24 hours before the valve began leaking again. The valve was repaired a second time with 18X sealant on June 25, 1998, a repair which was effective for about three and a half months. The valve began to leak again on about October 10, 1998, and was repaired a third time with 18X sealant on October 11, 1998. This repair was effective for about 24 hours before the leak recurred. PSE&G then requested and received an evaluation from the valve vendor to permit drilling additional injection ports without affecting the valve design basis, and performed a fourth repair with 18X sealant on October 23, 1998, which included drilling two additional injection ports. This repair was not successful in reducing the leakage. PSE&G believed that the injection pressure for the leak repair sealant was not sufficient to overcome system pressure to allow effective sealant compression and leak stoppage. At the end of the report period, PSE&G was evaluating additional actions which could be taken to repair the valve.

The inspectors concluded that overall, the activities associated with the various leak repairs of the valve demonstrated poor planning and communications between departments, and weak management oversight. For example, an ineffective sealant material was used for the first repair, i.e., its maximum effective temperature was too close to system temperature. This was believed to be the reason for the failure of the first repair. The inspectors identified that an inaccurate calculation resulted in the wrong volume of sealant being injected during the first two repairs. The third repair was completed on a weekend, shortly after the valve began to leak again, with minimal engineering support and management oversight. The fourth repair was poorly planned in that numerous delays were encountered prior to implementation of the repair. These were the result of various last-minute changes to the work package documentation including the need to identify contingencies for potential emergencies. Also, the planned location of the additional injection ports (on the back side of the valve) was not feasible from a personnel safety standpoint, but this was not discovered until a system walkdown on the morning of the job. In addition, one injection port was known to be "dead" by the leak repair personnel prior to the third and fourth repairs, but this was not known by PSE&G engineering personnel and not accounted for during planning for these repairs. Additionally, considering the relative importance of this valve, the inspectors concluded that overall communication with the NRC concerning the multiple leak repairs was weak, and done without sufficient management involvement.

PSE&G management acknowledged the inspectors concerns about the conduct of the valve leak repair efforts. Condition report (CR) 981023105 was written to document and evaluate the poor preparation for the October 23, 1998 leak repair attempt.

c. Conclusions

The multiple leak repairs performed on feedwater containment isolation valve, 12BF22, demonstrated poor planning and communications between departments, and weak management oversight. Additionally, overall communication with the NRC was weak considering the relative importance of the valve.

M4 Maintenance Staff Knowledge and Performance

M4.1 (Closed) LER 50-311/98-012-00&01: 22 Auxiliary Feed Water Pump Inoperability Caused By The Failure To Restore The Pump Runout Protection Pressure Transmitter To Service Following Calibration

a. Inspection Scope (62707, 92700)

The inspectors conducted an on-site review of the subject LER and verified selected corrective actions. The circumstances described in this LER were initially documented in NRC Inspection Report 50-272,311/98-06section M4.1, dated August 21, 1998. In summary, the event involved a failure by maintenance technicians to restore the 22 auxiliary feed water (AFW) pump runout pressure transmitter to service following a calibration activity, which resulted in the undetected inoperability of the pump for eighteen days. In this report, the inspectors concluded that this issue appeared to be repetitive in that similar examples of inadequate control of instrument valves and other plant equipment had been identified within the last year. As noted in the cover letter to the noted report, the NRC elected to delay making an enforcement decision in this case until PSE&G's LER describing the concern could be reviewed for corrective actions.

b. Observations and Findings

PSE&G submitted the original version of the subject LER on August 24, 1998. In this document, PSE&G committed to one corrective action designed to prevent recurrence of this repeat issue. Specifically, this action involved a presentation of the details of the noted event to all maintenance department personnel as a written discussion of operating experience feedback. This discussion focused on a reinforcement of existing management expectations with regard to procedure compliance and independent verification. In NRC inspection report 98-06, the inspectors noted that previous similar events relied on this same type of corrective action to prevent recurrence. Because this action had not been successful in precluding subsequent events, the inspectors determined that reliance on this type of corrective action following the 22 AFW pump event was not likely to be effective.

On September 28, 1998, PSE&G issued Supplement 1 to the subject LER which added another "preventive" corrective action commitment. Specifically, PSE&G committed to review programs and processes related to the control of safety system status to identify programmatic and organizational weaknesses that could compromise the ability of safety systems to carry out their design function. The

inspectors reviewed the results of this effort, which PSE&G conducted using a multi-disciplined team approach to root cause analysis. In the final report, the PSE&G team acknowledged that there have been numerous errors within the past two years involving equipment status control and independent verification, and concluded that ineffective training and lack of program ownership were key reasons why the issues recurred. As a result, the team recommended corrective actions which centered on periodic formal training of maintenance personnel with regard to status control and independent verification practices, as well as the appointment of a program manager who would be responsible for program monitoring and process enhancements. Lastly, the team proposed that a self-assessment in this area be conducted in six months to evaluate the effectiveness of these corrective actions.

The inspectors verified that PSE&G had entered these proposed actions into their corrective action program, with appropriate completion dates assigned. Additionally, the inspectors concluded that the multi-disciplined team review of the 22 AFW pump and other issues was reasonable and comprehensive, and likely to result in future performance improvements. However, the AFW pump was inoperable fifteen days longer than its technical specification (TS) allowed outage time, the AFW pump inoperability was identified only as a result of an attempt to place the pump in service to support a controlled shutdown of Unit 2 (i.e. not a planned surveillance activity), and corrective actions from previous similar issues were not effective in preventing recurrence.

TS 6.8.1.a requires that written procedures be implemented for the safety-related equipment listed in Regulatory Guide 1.33. PSE&G administrative procedure NC.NA-AP.ZZ-0005(Q), "Station Operating Practices," requires that AFW system components being aligned to support future operations shall receive an independent verification of position status. PSE&G maintenance procedure SC.IC-GP.ZZ-0003(Q), "General Instrument Calibration for Field Devices," requires that temporary modifications to affected systems and devices as a result of implementing the procedure shall receive an independent verification. However, maintenance technicians failed to properly restore and independently verify that a 22 AFW pump discharge pressure transmitter was returned to service after its calibration. The inspectors concluded that this was a violation of TS 6.8.1.a. **(VIO 50-311/98-08-03).**

c. Conclusions

PSE&G implemented reasonable corrective actions for a self-revealing event involving a failure by maintenance technicians to restore the 22 auxiliary feed water pump discharge pressure transmitter to service following a calibration. However, largely because of the repetitive nature of this issue, this failure resulted in a cited violation of technical specification 6.8.1 for failure to implement procedures.

M7 Quality Assurance in Maintenance Activities

M7.1 Offsite Independent Review and Oversight of Salem Maintenance

a. Inspection Scope (71707, 40500)

The inspectors attended a station Nuclear Review Board (NRB) meeting to evaluate the board's focus on safety and effectiveness in identifying and resolving conditions adverse to quality.

b. Observations and Findings

The inspectors noted that a valid quorum was present, and that the NRB contained at least three external consultants, as required by the station quality assurance program. The NRB reviewed previously identified issues in station maintenance department performance. Specifically, recent issues involving equipment status control and human performance were discussed. The NRB challenged the effectiveness of corrective actions and provided feedback based on previous experiences. The inspectors noted that the board remained focused on nuclear safety when discussing the issues at hand.

c. Conclusions

PSE&G's Nuclear Review Board provided sufficient oversight of Salem maintenance activities. Board recommendations effectively focused on improving safe conduct of plant maintenance activities.

M8 Miscellaneous Maintenance Issues

M8.1 Maintenance Focus Inspection

a. Inspection Scope

The inspectors reviewed various aspects of maintenance to assess the effectiveness of the work management program including work week schedule implementation and backlog reduction efforts. This review was performed to verify plant risk was minimized to ensure safe operation of the units.

b. Observations and Findings

The inspectors found that the work management process continued to mature but required continued management oversight to improve schedule development and adherence, and to reduce the large backlog of corrective maintenance activities. The inspectors noted that Salem implemented this new work management process at Unit 2 initially while restart efforts were being implemented for Unit 1. However, due to restart demands, PSE&G management oversight of the work management program was minimal and responsibility for the program fell to the working level supervisors and resulted in a lack of schedule adherence and accountability.

Therefore, the backlog remained high because activities were not effectively being incorporated into the work management process.

During observation of a T-4 planning meeting on September 17, 1998, the inspectors noted that personnel were struggling with the requirements of the work management program by trying to put too much work in the scope and not eliminating work early enough in the schedule. Although frustration was apparent from both work groups trying to get work into the schedule and planners trying to adhere to the established guidelines, work control center supervisors and planning supervisors were in attendance and facilitated the meeting to emphasize process adherence.

To improve the effectiveness of planning work, the licensee established more advance meetings 12 weeks prior to the start of work. The goals of these meetings were to identify and coordinate needed support activities such as parts procurement and scaffolding for inclusion in the schedule. Additionally, work support coordinators were granted database access to add their own needed work support activities to the schedule to ensure further that work would start per the published schedule.

The inspectors observed technicians performing maintenance on No.11 safety injection pump and No.12 emergency diesel generator. The inspectors noted that technicians adhered to work requirements, followed the work procedure, and complied with applicable administrative requirements. Work orders were properly completed and present at the job site. Technicians satisfactorily completed the assigned tasks.

The inspectors noted that the backlog reduction effort initiated in 1996 (discussed in previous NRC inspection reports as Programmatic Restart Issue No. 4.2) had changed. In March 1998, the licensee expanded the definition of backlog to include minor maintenance, corrective maintenance (CM) holds, lost work orders, and administrative holds (e.g. awaiting parts) increasing the Unit 2 backlog from 3756 to 6574. Although the licensee considered this change to be a positive initiative because the performance indicator now provided a more accurate reflection of the total backlog, including information on items in the closure cycle, the inspectors noted that no significant improvement had been made by the licensee for reducing the backlog, demonstrating the need for PSE&G to increase efforts in this area. At the time of this inspection, the Unit 2 CM backlog stood at 4890 and Unit 1 at 4410 with both trending down at an approximate rate of only 30 CMs per week per unit.

The backlog of CM work orders was reduced by approximately 1100 because the Work-It-Now (WIN) team eliminated duplicate work orders (WOs) and work no longer needed, and consolidated related work activities into single work orders. Feedback the inspectors received from maintenance workers in the field was that the workers felt they were becoming more effective and reducing radiation exposure by working several related work orders at a single time and they noticed some improvement in the scheduling of work over the past few months. Although the

licensee revised their goals for backlog reduction, the inspectors found that these goals were narrowly being met. The inspectors determined that better adherence to the requirements of the work management program would allow for additional CM activities to be completed. However, the inspectors concluded that continued management oversight was needed to ensure recently implemented improvements associated with the work management program would produce the desired results.

The inspectors compared the current Unit 2 backlog with the original 2564 items in the Salem report plan and found that if minor maintenance and administratively complete items were subtracted from the total to give a more accurate comparison, the current backlog would be approximately 5% larger. Although the inspectors found no items in the backlog to be improperly prioritized or the existence of any adverse conditions, the inspectors questioned the plant impact of having such a large number of outstanding activities.

The inspectors found that the Salem Planning and Scheduling Department had established an effective self-assessment program. These self-assessments and Quality Assurance reviews were self-critical, identified many weaknesses, and provided useful feedback to PSE&G management regarding implementation problems associated with work week scope identification and prioritization, and timely planning and coordination of work activities. Action Request (AR) No. 980917160 resulted from a work management center self-assessment that comprehensively identified numerous weaknesses. The inspectors did not identify any weaknesses that were not captured by this significance level 2 AR. The inspectors noted that a significance Level 1 had not been assigned to this AR because the licensee believed the root cause evaluation for these weaknesses was the same as for the previously completed Hope Creek AR (reference PIR 970128173) initiated in January 1997 that identified the same concerns with the work planning program. The inspectors agreed with the licensee's determination that poor oversight of the program resulted in slow implementation and improvement of the process.

The inspectors noted some progress by the licensee in reducing the number of work-in-progress activities and properly having such activities, including un-worked or partially worked packages, returned to planning for rescheduling and replanning. Additionally, the inspectors reviewed 15 Limiting Condition for Operation (LCO) maintenance plans and found improvement over the last six months where, on average, actual hours did not exceed planned work hours. Exceptions where planned hours were exceeded identified the reasons for the delays in the post-job critique sections of each plan for use by the work week manager in planning future work. Causes for the maintenance plan delays included the failure to schedule proper amount of time for the job, the need for scaffolding, identification of emergent work, and the failure to identify all required post-maintenance tests.

The inspectors noted licensee efforts to improve the effectiveness of planning included reassignment of maintenance personnel to the Planning Group. At the time of this inspection, nine craft personnel were aiding work week managers in planner positions. Additionally, eleven craft personnel were temporarily reassigned to the

WIN team, six to the Training Center, and one to the Corporate Safety Committee. During an interview, the Maintenance Department Manager noted that although these re-assignments hindered maximum backlog reduction efforts because there were less workers to perform work, the benefit gained from those experiences was worthwhile.

Performance indicators used to monitor the health of the work management process were found to be fully developed. However, the inspectors found that work week critiques required additional attention to improve work group performance and identify or evaluate the causes for problems encountered with schedule performance. The licensee had also self-identified this weakness and initiated corrective action by reassigning an experienced Hope Creek work week manager and former Work Control Center supervisor to oversee such critiques and improve the process.

c. Conclusion

The inspectors found that the backlog of outstanding corrective maintenance activities remained high and no significant improvement had been made in reducing it. The inspectors concluded that the program has been slowly evolving and required additional management oversight to ensure improvement. Performance indicators were useful and the Salem Planning and Scheduling department had established an effective self-assessment program.

M8.2 (Closed) IFI 50-272&311/97-81-01:Use of Risk Matrix During Reactor Operations

a. Inspection Scope (92901)

This item discussed an observation NRC inspectors made that operators were not familiar with the use of on-line maintenance risk matrices.

b. Observations and Findings

The inspector reviewed implementing procedure SC.OP-DD.ZZ-0027(Z), Probabilistic Safety Analysis Assessment, and determined the procedure was adequate. All operators received training on this procedure during their last operator requalification training cycle. The inspector also interviewed operators on shift (two crews; approximately eight operators) to assess their level of knowledge regarding on-line maintenance risk matrices. The operators were familiar with the risk matrices available in the respective control rooms and demonstrated how to use the matrices to evaluate risks associated with planned and emergent maintenance. In addition, the operators stated that the probabilistic safety analysis group was always available to perform risk assessments for situations not bounded by the matrices.

c. Conclusions

Based on the interviews, the inspectors concluded operators were familiar with and understood how to apply the risk matrices. This item is closed.

III. Engineering

E2 Engineering Support of Facilities and Equipment

E2.1 Effectiveness of System Engineering to Support the Safe Operation of the Plant

a. Inspection Scope (37550)

The inspector evaluated the effectiveness of Salem system engineering to support the safe operation of the plant. This evaluation included, on a sampling basis, a review of the staff experience and qualifications, responsibilities and training, involvement in day-to-day plant activities, communication with other engineering and plant organizations, and resolution of plant issues. Also, the inspector conducted partial system walkdowns and interviews of staff and supervisory personnel.

b. Observations and Findings

Staff Composition

The Salem system engineering staff is comprised of approximately 25 engineers of various experience and backgrounds. Length of experience varied from a few months to more than 20 years of nuclear experience. Some engineers, with several years of nuclear experience, had limited system experience because they had recently transferred from another department or other utility. Most engineers had several systems assigned to their responsibility. Inspector interviews of nearly half the system engineers found them to have a good general understanding of their systems and, in some cases, a good understanding of general plant systems. When experience lacked, interviews indicated willingness to solicit assistance from more experienced and supervisory personnel.

System Engineers Training

Several years ago, personnel assigned to the system engineering group received several months of training in system engineering. Recently the licensee has opted to shift to an on-the-job training. Responsibilities are assigned based on previous experience and increased, as appropriate. Progress is monitored and management coaching is ongoing. For example, on Tuesdays and Thursdays, management personnel from various disciplines and organizations conduct system performance reviews. Although current system performance problems are discussed during these meetings, the review board examines the depth of knowledge the system engineer has of the system design, functions, operation, and interfaces. Because of the meeting expectations and as a result of the meeting interaction, the system engineer has a better understanding of the system itself and a list of look-up questions he needs to address, following the meeting. The inspector found the current training practice acceptable.

System Engineering Procedures

The roles and responsibilities of the system engineers are delineated in a variety of internal memoranda and procedures. The inspector selected four procedures for his review, including SC.SE-DD.ZZ-0008(Z), "System Engineering Final System Readiness Review - UFSAR Macro-Review Desk Guide"; SC.SE-AP.ZZ-0001(Q), "Follow-up Operability Assessment"; SC.TE-DD.ZZ-0004(Z), "System Engineering System Window Management Desk Guide"; and SC.TE-DD.ZZ-0007(Z), System Engineering System Notebook Desk Guide."

The inspector's review of the above procedures found them to contain sufficient guidance for the proper evaluation of the system design, for documenting and monitoring its performance, for managing system related maintenance activities, and for assisting the operating staff in assessing the system or component operability. The inspector's review of the implementation of these procedures identified no specific concerns. However, he did observe that some notebooks containing system performance data were not up-to-date. Although the effective use of the system notebook provides a good visual tool to quickly analyze component and system performance data and identify trends, the inspector did not consider this a major flaw of the system monitoring program implementation since the data was available to the engineers in a computerized database.

System Engineering Involvement in Plant Activities

To address day-to-day engineering support of plant operations and emerging issues, PSE&G recently established the Maintenance Engineering Department. The reorganization was also to permit the system engineers to concentrate on the performance of the systems assigned to their responsibility and to better manage activities related to their systems. To evaluate the effectiveness of the organizational changes, the inspector discussed with the system engineers their current role, their involvement in the plant day-to-day activities, and their ability to discharge their responsibilities.

The inspector found that system engineering was still undergoing a transition period, but that improvements were noticeable. The system engineers were still operating somewhat in the reactive mode, but communications with maintenance engineering and operations were good. They were kept informed of ongoing activities related to their systems, and they were called upon to evaluate issues involving their systems. Time for system performance monitoring had also improved and system engineers conducted regular system walkdowns. The inspector specifically addressed current performance monitoring of the direct current, service water, and radiation monitoring systems. Except as described in subsequent sections of this report, the inspector identified no areas of concern.

Discussion with system engineering management indicated current plans to further strengthen the role of the system engineer. They had developed a system engineering master plan that was to be implemented early in 1999. The plan entailed the identification of top technical issues and the development of system

health reports which, reviewed by system teams, would ultimately end up in the work management process.

c. Conclusions

The Salem system engineering staff included a nucleus of knowledgeable system engineers with several years of nuclear experience. System experience was limited in some cases, but engineers indicated strong willingness to seek guidance from more experienced personnel. Individual system training was acceptable. The system performance review meetings were good management tools to evaluate individual knowledge of the system and to impart integrated insights on the system.

Current system engineering procedures contained sufficient guidance for the proper implementation of the system engineering monitoring program. System engineers continued to operate partly in a reactive mode, despite the establishment of a maintenance engineering group. However, clear areas of responsibility had been established and the engineers were assuming system responsibility. Also, a system engineering master plan was underway to further strengthen the role of the system engineer and to better manage work activities. Communications with maintenance engineering and operations were good.

E2.2 Radiation Monitoring System Performance

a. Inspection Scope (37550)

The inspector evaluated the performance monitoring of the Radiation Monitoring System (RMS).

b. Observations and Findings

The inspector's review of system performance trends within the Salem maintenance rule program indicated that the maintenance unavailability times for most monitored RMS components for both Salem Units significantly exceeded the hourly goals for those components during the current operational cycle. For instance, for the waste liquid process monitors R18, the licensee had set a goal of less than 640 hours/unit for the entire cycle. The October 5, 1998, report showed that, for these instruments, the unavailabilities were 4352 and 3334 hours for Units 1 and 2, respectively.

Discussions with responsible personnel indicated that the unavailable hours represented the hours expended during the previous 18 months and, therefore, reflected some of the time when the reactors were shutdown. The licensee agreed, nonetheless, that the reliability of the system and some of the corrective actions taken during the system readiness review had not met PSE&G expectations. PSE&G had already recognized the problem and initiated actions to remedy the instrument availability concerns.

The system problems had been previously evaluated in a level 2 analysis and a system team had been established on June 10, 1998, to prepare an integrated recovery plan. In addition, the licensee evaluated the program of another plant that had achieved reasonable success with their radiation monitoring program. As a result of multiple channel failures experienced during the previous month (Performance Improvement Report (PIR) 980914147), the licensee initiated a level 1 root cause analysis and established a review team from several disciplines to perform a comprehensive review of past failures and failure modes, and to develop recommendations for improving system availability and reliability.

Although the root cause analysis was ongoing, discussion with the system manager, the root cause analysis team leader, and a team member indicated that progress was being made in addressing the system problems. Discussions also indicated awareness of the problems and good management support.

c. Conclusions

The licensee continued to experience reliability and availability problems with radiation monitors at both Salem units. However, appropriate steps were being taken to address the instrument failures. The root cause analysis multi-disciplinary team showed good understanding of the issues involved. Good management support of the effort was also evident.

E2.3 Carbon Dioxide Preventive Maintenance Program

a. Inspection Scope (37550)

On September 7, 1997, the licensee performed a carbon dioxide (CO_2) discharge test to evaluate the ability of the Hope Creek CO_2 system to produce the required gas concentration (34%) in the "A" emergency diesel generator room that had been recently modified (design change package 4EC-3644). As described in a subsequent licensee evaluation, PIR No. 970907107, the test was unsuccessful due to a failure of the master valve seals. The failure of the seals allowed the CO_2 to enter in the valve upper chamber and prematurely reclose the valve. The licensee attributed the seal failure to lack of preventive maintenance (PM) that allowed the deterioration of the valve seals to go unnoticed. The inspector evaluated the action that had been taken at Salem to address the CO_2 test failure and to prevent similar failures at the Salem units.

b. Observations and Findings

The licensee's review of the Hope Creek failed test resulted in the assignment of corrective action item CRCA No. 02, to the Salem responsible system engineer to evaluate the PM program for CO_2 master valves at Salem. The task was assigned on October 4, 1997 and scheduled for completion on May 30, 1998.

The Salem responsible engineer's review of the issue found that no PM program existed at Salem for the CO_2 valves and identified 27 valves for which a program

should be established. On May 29, 1998, the CRCA was closed as completed and a new CRCA, No.04, was issued to "determine the Salem CO_2 valve PM frequency." The date assigned for completion of this task was July 30, 1998.

The evaluation performed by the engineer under the new task concluded that a regular inspection recommended by the vendor for these valves was not cost effective and recommended valve replacement at a "regular frequency." Based on his review of the maintenance history of the Salem valves, he recommended that the valves located outdoors be replaced at 90-month intervals. For the indoor valves he recommended replacement at 126-month intervals. Based on his conclusions, on July 30, 1998, CRCA No. 04 was closed and CRCA No. 05 was opened to include the CO_2 valves in the instrument maintenance PM program. The completion date for this new task was established to be July 30, 1999.

Because: (1) the Salem CO_2 valves had been in operation for more than 20 years, i.e., long past the service life that had been established for them; (2) the valves had not been in the Salem PM program and, hence, had not been inspected or serviced at regular intervals (yearly, as recommended by the vendor); and (3) the latest CRCA was another, but not the final step, in replacing the valves, the inspector questioned the licensee's schedule for addressing the issue and the basis for PSE&G's confidence in the ability of the system to mitigate the consequences of a fire in any of the protected zones.

The inspector's discussions with licensee engineering indicated that they believed that the "puff" test (a test that verifies the functionality of the valves every 18 months) was indicative of the ability of the system to perform its function. However, the same test had not revealed the degradation of the master valve seals at Hope Creek, indicating that the test does not also verify the adequacy of the seals when exposed to the CO_2 temperature and pressure for an extended time, as during full CO_2 discharge.

Following the discussions with the inspector, the licensee inspected a valve that had been recently replaced due to a flange seal failure and found the CO_2 seals acceptable. A physical observation of the valve by the inspector confirmed that the o-rings were still intact and that the metal surface in the sealing area had no noticeable scars to the touch. However, the licensee had not performed a detailed examination of the o-rings to confirm their adequacy or of the sealing area to confirm that it did not contain any scars. Therefore, PSE&G had not demonstrated the ability of the valve to perform its intended function.

Following the inspection, on October 19, 1998, the licensee submitted an analysis in which PSE&G concluded that reasonable assurance existed that the CO_2 valves would be able to perform their design function. In the analysis the licensee indicated that the conclusions were based on operating experience with the system, observations made during the review of the recently failed Salem valve, and discussions with the valve vendor. Although preliminary, because it did not carry the required review and approval signatures, the inspector reviewed the analysis, but raised questions about the licensee's conclusions for the following reasons:

(1) the lack of Salem valve failures during puff tests did not assure that a valve would not fail, if subjected to a full CO_2 discharge. A Hope Creek valve had failed; (2) the Hope Creek analysis attributed the failure to lack of preventive maintenance. The 26 Salem valves had not undergone preventive maintenance since installation; (3) the Salem analysis had set the service life of indoor valves at 10.5 years. Most of the Salem valves were nearly twice that age; (4) the evaluation of the failed Salem valve was not supported by strong physical evidence of the condition of the valve; and (5) the vendor conclusions regarding the adequacy of the puff test, while reasonable, were not supported by the Hope Creek experience.

Discussions with licensee engineering indicated that PSE&G had initiated steps to expedite replacement of the valves. This decision was supported by the analysis recommendation that valves not replaced during the last ten years should be replaced at the next available fire protection work week window. In addition, the licensee recommended that valves be examined, as they are replaced, so PSE&G may better define the valves' future replacement schedule. The inspector considered these actions important to the proper resolution of the issue.

c. Conclusions

The licensee's response to a question associated with the potential for age-related seal failures of CO_2 valves was weak. The licensee was slow in addressing this issue, which was first identified at Hope Creek in September 1997. When the licensee confirmed the applicability of this failure to Salem, the licensee did not assure that the CO_2 valves would perform as designed. Subsequent to NRC questioning, the licensee developed an analysis that provided the bases for assuring that the valves would perform as designed. The licensee indicated that PSE&G had initiated steps to expedite replacement and examination of additional valves during the next work week window. Although this action appeared reasonable, this issue is left unresolved pending NRC review of the results of the licensee's examination of these valves. **(URI 50-272 & 50-311/98-09-04)**

E2.4 Emergency Diesel Generator Reliability Program

a. Inspection Scope (37551)

The inspectors reviewed Salem's emergency diesel generator (EDG) reliability program. The inspectors held discussions with system engineering and performance monitoring personnel, and reviewed recent EDG performance data. Procedure SC.SE-PR.DG-0001, *"Emergency Diesel Generator Reliability Program,"* was used as a reference.

b. Observations and Findings

Following implementation 10 CFR 50.65 (the maintenance rule), PSE&G system engineering and performance monitoring personnel discontinued the use of procedure SC.SE-PR.DG-0001 for implementation of the EDG reliability program. The inspectors reviewed the currently employed methods for EDG reliability

monitoring, and noted that the current monitoring methods paralleled the requirements of procedure SC.SE-PR.DG-0001. Although the procedure was still active, PSE&G personnel were in the process of deactivating it. System engineering personnel were currently reviewing the procedure to ensure that all aspects of the former monitoring program were preserved under maintenance rule monitoring. From a review of recent EDG performance monitoring data, the inspectors noted that the performance criteria have been established to maintain target reliability values, established under 10 CFR 50.63 (the station blackout rule). Recent reliability data showed that the unit 1 and 2 EDGs were above their target values.

c. Conclusions

Although established emergency diesel generator (EDG) reliability monitoring program guidance was not actively employed, PSE&G personnel were adequately monitoring EDG reliability under the requirements of 10 CFR 50.65. PSE&G established appropriate performance criteria to ensure that EDG reliability commitments were maintained.

E7 Quality Assurance in Engineering Activities

E7.1 Corrective Action

a. Inspection Scope (40500)

The inspectors reviewed PSE&G's Action Request (AR) system to confirm proper use of the condition resolution (CR) and business process (BP) subsystems. This inspection was performed to evaluate the effectiveness of the corrective action program for identification and characterization of problems and implementation of immediate, interim, and final actions for resolution of issues. A sampling of low priority CRs (i.e. level 3) and BPs was performed to determine the impact and extent of any incorrect processing that could result in bypassing any needed operability reviews or timely resolution of issues. This review was performed following the identification by the NRC of four improperly categorized Hope Creek ARs that utilize the same AR program that circumvented the corrective action system (reference AR 981006240).

b. Observations and Findings

PSE&G administrative procedure NC.NA-AP.ZZ-0000(Q), *Action Request Process*, describes the method for reporting conditions requiring corrective action, enhancement, or interdepartmental support. The two primary types of ARs are the CR request, used to identify and correct a condition adverse to quality, and the BP request, used for enhancement or support that is not a condition adverse to quality. Attachment 2 to this procedure provided examples of items that should be categorized as significance level 3 CRs as well as items that are not conditions adverse to quality (BPs). The inspectors selected 20 BPs and 20 CRs to verify the appropriateness of the assigned characterization of the issues. After a more detailed review, the inspectors discussed 10 BPs with the corrective action group

and determined that all were properly categorized in accordance with the above procedure and no operability concerns were identified. A listing of those ARs reviewed is provided as Attachment 1 to this report.

(Closed) Violation 50-272; 311/98-81-02- Trending of Level 3 ARs

The inspectors reviewed two quarterly trend reports and the September 1998 corrective action process performance indicator report that illustrated trends for several program aspects over the past two years. These reports provided statistical information on the number of open CRs by department, their age and significance level, as well as overdue actions and due date extensions. These reports were the result of actions from the Management Improvement Plan for the Corrective Action Program taken partly in response to concerns identified by the Unit 1 NRC Readiness Assessment Team Inspection (RATI) in February of this year. The RATI found that level 3 CRs were not being trended by all departments since program inception as required by procedure NC.NA-AP.ZZ-0006(Q). In response to this violation, the licensee began trending level 3 CRs and presented the results of their analyses in the quarterly trend reports. However, the inspectors found that this trend analysis did not enable the reader to identify actions for improving performance because it was difficult to identify common causes for the CRs generated. This difficulty stemmed from the fact that level 3 CRs did not have cause codes assigned.

Although the licensee was identifying the three most significant programs/process trends in the trend reports, the inspectors noted that these were merely the most often used programs/processes. The most significant issues identified were corrective maintenance, work control, and configuration control, however, the ability to gain meaningful insight from these large categories was very limited.

Additional corrective actions taken by PSE&G to improve management oversight and the effectiveness of the corrective action program (CAP) included development of a level 1 Action Plan to continue performance improvement and strengthen the value of information collected. Details of these actions were provided in the licensee's response to the Notice of Violation, dated March 8, 1998 (LR-N980308) and included plans to have each department, instead of the corrective action group, develop its own understanding of human performance and error trends and correct problems within its own department. The inspectors agreed that this approach would enable a better understanding of issues and allow for more meaningful trending. Based on review of the licensee's corrective actions, the inspectors concluded that additional management oversight of the CAP was evident and the licensee had completed trending of level 3 ARs. This violation is closed.

Self-Assessment

The inspectors selected various findings from two engineering self-assessments and five quality assurance (QA) audits and surveillances to determine if the licensee was appropriately following up on identified issues, whether corrective actions were timely and properly prioritized, and to evaluate the significance of this sample of

findings to determine the effectiveness of self-assessment efforts. The assessments reviewed are also listed in Attachment 1 to this report.

The inspectors found that previous self-assessment findings were reviewed and dispositioned properly and effectiveness reviews were included in the scope of subsequent reviews. Condition reports generated for identified discrepancies appropriately addressed issues and were found to be properly prioritized for significance and subsequent management attention based on AR program guidance. The inspectors noted that the engineering self-assessments were well scoped and highlighted needed improvements. QA Audits were self-critical and effective in identifying and presenting findings.

Based on the findings and recommendations generated, the inspectors concluded that engineering self-assessments and QA reviews provided valuable insights. Through the review of previous audits and assessments of the CAP and Salem AR 9810001366, the inspectors found that CRs with incomplete corrective actions had been improperly closed to BPs and that CR corrective actions needing extensions for completion were also closed to BPs bypassing the extension process which is a performance trended area. Although these discrepancies were administrative in nature, the inspectors remained concerned that the possibility existed for problems to be mischaracterized, not reviewed for operability, and not resolved in a timely fashion. The inspectors noted that the licensee had initiated efforts to correct the above discrepancies via the CR process. Although these efforts were still in development, the licensee had already developed a training overview of the CAP philosophy to improve general understanding of how to implement CR corrective actions and CR evaluations and began refresher training sessions for employees two months prior to this inspection.

c. Conclusions

Within the scope of the inspection, the inspectors found that the licensee appropriately utilized the condition resolution and business process subsystems for resolution of sampled issues. Although the disposition of action requests selected for review did not identify any improperly categorized findings, the inspectors remained concerned that problems could be mischaracterized and bypass needed operability reviews. However, PSE&G had initiated efforts to correct the self-identified misapplications within the action request system. Improved management oversight of the corrective action program was evident. Engineering self-assessments and quality assurance reviews provided valuable insights.

E8 Miscellaneous Engineering Issues

E8.1 Spent Fuel Pool Cooling and Refueling Activities

a. Inspection Scope (37551)

In response to an NRC survey of spent fuel practices and spent fuel pool (SFP) cooling design, the results of which were documented in NRC Inspection Report 50-

272&311/96-05, PSE&G committed to conduct an analysis of SFP structures and components with pool temperatures in excess of 180°F. PSE&G confirmed this commitment in a letter to the NRC dated August 2, 1996, and stated that this activity would be completed prior to the next core offload. The NRC created an inspector follow up item (IFI) 50-272&311/96-08-08to track this issue. PSE&G also committed to establish procedural controls to ensure that the SFP heat load is maintained below the analyzed value; this item was tracked by IFI 50-272&311/96-08-10. During this report period, the inspectors reviewed the status of these items to verify that PSE&G was actively pursuing resolution of these issues.

b. Observations and Findings

(Closed) IFI 50-272&311/96-08-08:Analysis of Spent Fuel Pool Structures, Systems and Components With Pool Temperatures Above 180°F

The inspectors verified that the SFP high temperature analysis was completed, which initially indicated that structural integrity of the SFP would be maintained even under boiling conditions. As a result, PSE&G concluded that no SFP design modifications would be necessary to cope with worst case conditions. However, based on subsequent NRC questions, PSE&G determined that the validity of the initial analysis was suspect, and later committed in a January 19, 1998 letter to seismically qualify the SFP cooling system. This upgrade would preclude the need to assume a loss of the SFP cooling system following design basis seismic events, and therefore not subject the SFP to unacceptably high temperature conditions. Several subsequent meetings and letters have clarified PSE&G's position and planned actions to address this issue. Additionally, the inspectors verified that PSE&G completed and planned activities, which include the installation of isolation valves or caps on SFP liner drain lines, were entered in PSE&G's corrective action program.

(Closed) IFI 50-272&311/96-08-10:Procedural Controls For Spent Fuel Pool Decay Heat Load Management

The inspectors noted that PSE&G had established and maintained a program for assessing shutdown plant safety, including controls for SFP cooling, governed by procedure SC.SA-AP.ZZ-0055(Q), "Outage Risk Management." Attachment 1, Section 4.0 of this procedure provides criteria to assess the availability of various SFP components and support systems during the development of refueling outage schedules. However, this procedure did not adequately address all of the concerns raised during the initial NRC survey or subsequent reviews. The inspectors verified that PSE&G had entered its commitment to develop more sophisticated administrative controls for SFP decay heat load into the corrective action program. Based on a conversation with the responsible design engineering personnel, and a review of the corrective action request used to track this issue, the inspectors learned that this committed activity was scheduled for completion by December 30, 1998. The next core offload was scheduled for April 1999 (Unit 2 refueling outage).

c. Conclusions

PSE&G was actively engaged in the resolution of concerns raised by the NRC regarding spent fuel pool cooling design and decay heat load management, and has implemented a reasonable approach to completing these activities prior to the next core offload.

IV. Plant Support

R1 Radiological Protection and Chemistry (RP&C) Controls

R1.1 General Comments

The inspectors reviewed the controls for high radiation areas and locked high radiation areas and found them to be adequate. They also observed a secondary chemistry analysis and determined that it was properly performed.

R3 RP&C Procedures and Documentation

R3.1 Maintenance of the Offsite Dose Calculation Manual (ODCM)

a. Inspection Scope (71750)

The inspectors reviewed the adequacy and the implementation of PSE&G's controls for maintaining the Salem and Hope Creek ODCM.

b. Observations and Findings

PSE&G procedure NC.RC-RR.ZZ-0001, *"Maintenance of the Salem and Hope Creek Offsite Dose Calculation Manual,"* provides guidance for administrative control of the station ODCM. The inspectors reviewed a March 1998 ODCM revision, which included editorial changes and a correction of an algebraic error inadvertently included in a previous revision. Although the revision was prepared by a senior chemistry supervisor and reviewed by the station operations review committee, the necessary staff signatures specified in NC.RC-RR.ZZ-0001 were not obtained. This discrepancy resulted from chemistry department organizational changes. Additionally, the inspectors noted that PSE&G personnel performed the most recent functional review of procedure NC.RC-RR.ZZ-0001 within a 32 month interval, rather than on a 24 month interval required by the procedure. PSE&G has subsequently reassigned ODCM administrative control responsibilities and revised procedure NC.RC-RR.ZZ-0001 to improve the ODCM revision and review processes. These failures to follow procedure NC.RC-RR.ZZ-0001 are violations of minor significance and are not subject to formal enforcement action.

c. Conclusions

Due to recent organizational changes, chemistry department personnel did not process a revision to the offsite dose calculation manual in accordance with station

procedural guidance. The inspectors concluded that PSE&G personnel applied an appropriate level of technical and management review to process the revision, and implemented adequate corrective actions for the identified procedural non-compliances.

P2 Status of EP Facilities, Equipment, and Resources

P2.1 Emergency Response Facilities Readiness

a. Inspection Scope (71750)

The inspectors performed a walkdown of the Salem emergency operations facility (EOF) and technical support center (TSC) to evaluate their state of readiness. The inspectors also verified the inventory and condition of EOF and TSC equipment specified in PSE&G's emergency plan.

b. Observations and Findings

The inspectors noted that the physical condition of the noted facilities was well maintained. All emergency equipment specified in the emergency plan was available, and all calibrations for radiological assessment instruments were current. Each facility contained current controlled copies of the emergency plan and implementing procedures.

c. Conclusions

PSE&G's emergency operations facility and Salem's technical support center were properly maintained. All necessary emergency equipment and procedures were adequately controlled.

S1 Conduct of Security and Safeguards Activities

S1.1 General Comments

The inspectors performed a review of vehicle control inside the protected area, including interviews with various security personnel, with no discrepancies noted.

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 October 28, 1998. The licensee acknowledged the findings presented.

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

X2 Management Meeting Summary

On September 30,1998, a meeting between NRC and PSE&G management was held on-site to discuss the Systematic Assessment of Licensee Performance (SALP) report which was issued on September 15, 1998. In addition, meetings between NRC and PSE&G management were held in the NRC Region I office to discuss Salem Unit 2 Steam Generator 23 Primary-to-Secondary Leakage and PSE&G's Business Process Redesign, on October 13 and 21, 1998, respectively. The overhead transparencies used during these meetings are included as Attachments 2 & 3 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 61726:	Surveillance Observations
IP 62707:	Maintenance Observations
IP 71707:	Plant Operations
IP 71750:	Plant Support Activities
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

50-311/98-09-01	NCV	Failure to meet TS 3.3.3.7 Table 3.3-11 Item 19-RVLIS. (Section O8.1)
50-272/98-09-02	NCV	Failure to align the control room emergency air conditioning system for single train operation. (Section O8.4)
50-311/98-09-03	VIO	Auxiliary feed water pump inoperability. (Section M4.1)
50-272&311/98-09-04	URI	Weak resolution of the carbon dioxide discharge valve seals failure. (Section E2.3)

Closed

50-272&311/96-08-08	IFI	Analysis of spent fuel pool structure, systems and components with pool temperatures above 180° F. (Section E8.1)
50-272&311/96-08-10	IFI	Procedural controls for spent fuel pool decay heat load management. (Section E8.1)
50-272&311/97-81-01	IFI	Use of risk matrix during reactor operations. (Section M8.2)
50-272&311/98-81-02	VIO	Trending of level 3 action requests. (Section E7.1)
50-311/98-001-00	LER	Failure to Meet Technical Specification 3.3.3.7 Table 3.3-11 Item 19. (Section O8.1)
50-272/98-008-00	LER	Inadequate Testing of the Salem Unit 1 Containment Air Locks Resulted in Entering Technical Specification 3.0.3. (Section O8.2)
50-311/98-011-00	LER	Engineered Safety Features Actuation During A 4KV Automatic Transfer Test. (Section O8.3)
50-311/98-012-00& 01	LER	Auxiliary feed water pump inoperability (Section M4.1)
50-272/98-013-00	LER	Operation With Technical Specification Equipment Out of Service. (Section O8.4)

LIST OF ACRONYMS USED

AFW	Auxiliary Feed Water
AR	Action Request
BP	Business Process
CAP	Corrective Action Program
CARB	Corrective Action Review Board
CAV	Control Area Ventilation
CM	Corrective Maintenance
CO_2	Carbon Dioxide
CR	Condition Resolution
CREACS	Control Room Emergency Air Conditioning System
DAS	Data Acquisition System
EDG	Emergency Diesel Generator
EOF	Emergency Operations Facility
ESF	Engineered Safety Features
GDC	General Design Criteria
HVSD	High Voltage Shutdown
IFI	Inspection Followup Item
LCO	Limiting Condition for Operation
LER	Licensee Event Report
MCSLPM	Main Coolant System Leak Air Particulate Monitor
NOV	Notice of Violation
NRC	Nuclear Review Board
NRC	Nuclear Regulatory Commission
ODCM	Offsite Dose Calculation Manual
PDR	Public Document Room
PIR	Performance Improvement Report
PM	Preventive Maintenance
PMT	Post-Maintenance Test
PSE&G	Public Service Electric and Gas
QA	Quality Assurance
RMS	Radiation Monitoring System
RVLIS	Reactor Vessel Level Indication System
SFP	Spent Fuel Pool
SORC	Station Operations Review Committee
SPT	Station Power Transformer
TS	Technical Specification
TSC	Technical Support Center
WIN	Work-it-Now
WO	Work Order

ATTACHMENT 1

Corrective Action Documents Reviewed

Engineering Self-Assessments

- Nuclear Engineering - Configuration Control Processes (No. 980519096)
- Nuclear Engineering - Design Change Control (No. EA-A-97-01)

Quality Assurance Surveillances

- Planning and Scheduling Corrective Action Evaluation, September 30, 1998
- Corrective Action Evaluation and Implementation, March 27, 1998
- Operations Training Corrective Action Program Implementation and 1998 ASER Validation, September 14, 1998

Quality Assurance Audits

- Nuclear Business Unit Corrective Action Audit 97-190-2
- Nuclear Business Unit Corrective Action Audit 98-190-1

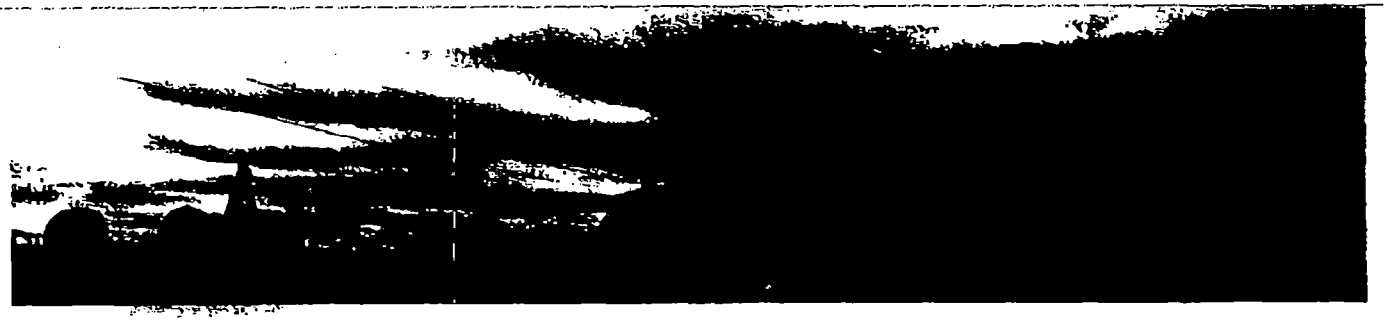
Business Process Requests

- 970725131 Molded Case Circuit Breakers
- 971218092 Servomotor Linkage Inspection
- 980921234 EDG2B K1C Relay Replacement
- 980916133 Configuration Control
- 970512145 Station Blackout Program
- 971202185 Equivalent Replacement Process
- 980519096 Configuration Control Process Assessment
- 980225202 Delete Procedure SH.MD-GP.ZZ-0205
- 980527081 Issue Calculations Per Design Change
- 951124112 125 VDC Coordination

Level 3 Condition Resolutions

- 971016216 Repair Of Eroded Steel
- 980706123 Safety Significance Not IAW SC.DE-AP.ZZ-0019(Q)
- 971023200 Switchgear Room Motor
- 960925252 Incorrect DCP Status During Implementation
- 970227059 Limitorque Maintenance Update 96-01

ATTACHMENT 2



Salem Unit 2
Primary-to-Secondary Leakage
Steam Generator 23

October 13, 1998

Current Leakage in SG 23

- ~~Increased background was notice by~~ Chemistry on routine gross activity measurements
- A resin column was placed inservice on SG 23 and Na-24 and I-133 was detected
- During 10/3-10/6 a resin column was inservice to daily trend leakage
- Maximum leakage detected ~2.5 gpd

Steam Generator 23 Plugging History

- Steam Generator 23 has 136 tubes plugged
  - All row 1 tubes (94) are preventatively plugged
  - Two(2) tubes plugged for loose parts
  - Eight (8) tubes plugged for ODSCC at top of tubesheet (TTS)
  - Five (5) tubes plugged for ODSCC at TSPs
  - Four (4) tubes plugged for TTS PWSCC
  - Five (5) tubes plugged for Coldleg wastage
  - Thirteen (13) tubes plugged for AVB Wear
  - Five (5) tubes plugged of other reasons

Steam Generator Plugging Data

Unit	S/G	Row 1 U-Bend	CD TTS IGA/SCC	"AXIAL" CD TSP IGA/SCC	"CIRC" CD TSP IGA/SCC	TSP PWSCC	"AXIAL" TTS PWSCC	"CIRC" TTS PWSCC	CIL Wastage	NRCB 88-02	AVB Wear	Loose Parts	Other	TOTAL	Percent Plugged
2	1	0	4	2	2	0	30	0	0	2	17	0	100	157	4.634%
2	2	47	6	0	9	1	43	1	6	5	6	0	49	173	5.106%
2	3	0	8	3	2	0	4	0	5	1	13	2	98	136	4.014%
2	4	48	7	0	9	2	92	3	9	2	7	4	57	240	7.084%
	Total	95	25	5	22	3	169	4	20	10	43	6	304	706	5.210%

TOTAL PLUGGED:

Unit 2 - 706 - or - 5.210%

Notes: (1) Number of tubes per S/G is 3388

(2) The present analyzed plugging limit is 10%. Per S-C-RC-MSE-0807 the administrative plugging limit is 6%. Plugging beyond 6% is permitted once the fuels group performs a return to power justification.

Primary-to-Secondary Leakage Limits

- Technical Specifications limit - 500 gpd
- EPRI Primary-to-Secondary Leakage Guidelines limits 150 gpd and 60 gpd/hr
- Salem S2.OP-AB-SG-0001(Q) Steam Generator Tube Leak Administrative Leakage limits - 140 gpd and 60 gpd/hr

Leakage Monitoring Systems

- Condenser Air ejector Rad Monitor - 2R15
  - No indication of leak
- Main Steam N-16 Rad Monitor - 2R53
  - No indication of leak
- Blowdown Rad Monitor - 2R19
  - Slight increase in background since shutdown, does not correlate to when leak was identified
- Chemistry Grab Samples

Other Actions

- Reviewed S2.OP-AB.SG-0001 SG Tube Leak procedure limits with Shift operators
  - Entry condition not met, results of daily analysis will determine if/when abnormal procedure is entered (~5-10gpd)
- Trending leakage on daily basis until leak stabilizes
- Making contingency preparations for steam generator tube Leakage outage

Other Actions (Con't)

- Steam Generator tube rupture training twice for each crew in last requal training cycle
- Additional training for each crew for smaller SG tube leak commencing this week
- Steam and Water leakage in plant being corrected on a priority basis

ATTACHMENT 3

Public Service Electric & Gas

Bert Simpson

Building a One-Site Philosophy

Where We Are Headed with Business Process Redesign/SAP

10/20/98
King of Prussia

PSE&G

Introduction

- **Where We Are Going (Building a One-Site Philosophy)**
- **Business Process Redesign**
  - The BPR Process
  - What is SAP?
  - Change Without Impact on Safety
- **Where We Are With Work Management**
- **Implementation Schedule**
- **Challenges**

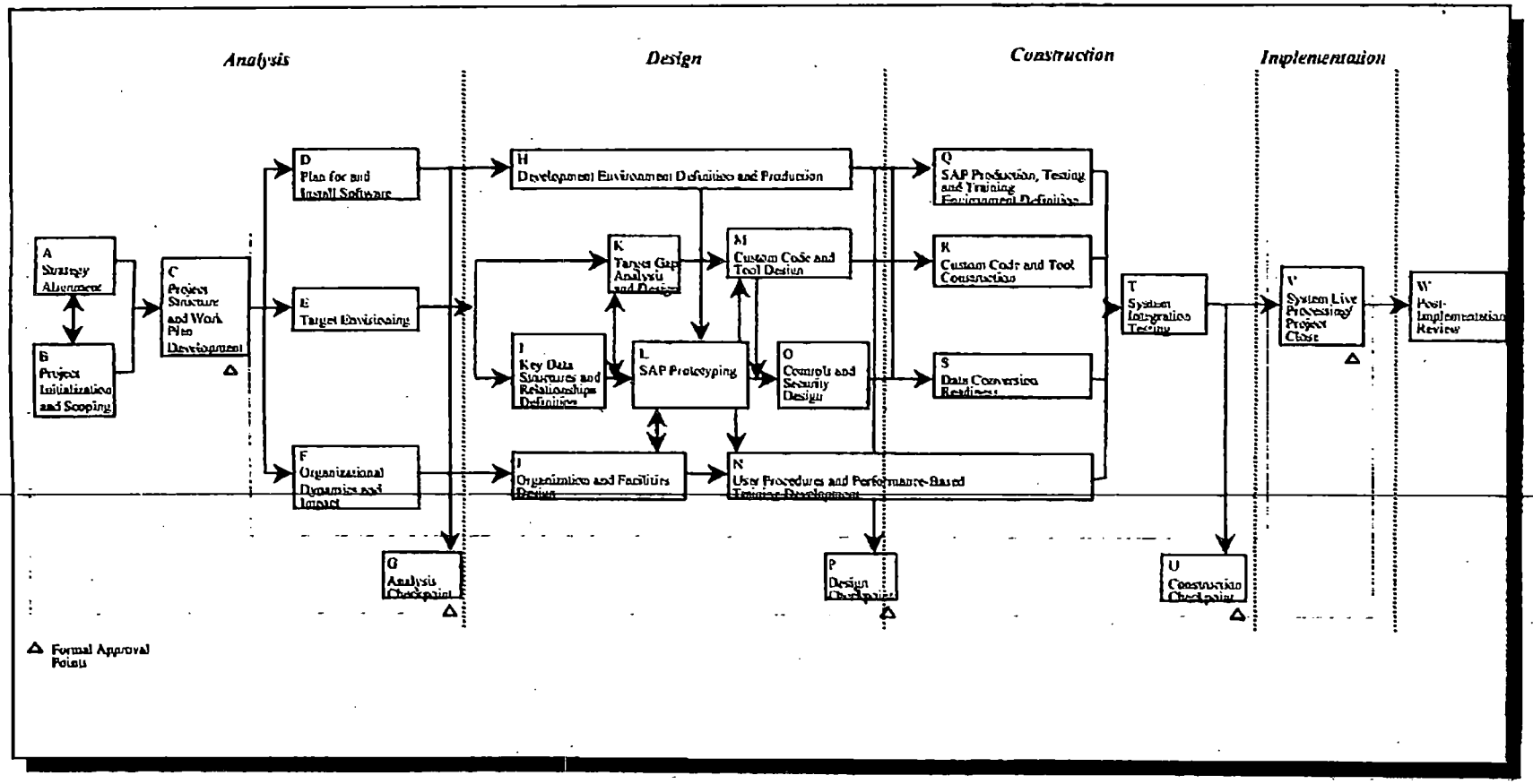
Where We Are Going

- **The NBU operated as two separate sites -- Salem and Hope Creek**
- **One-site philosophy**
  - enhanced focus on nuclear safety
  - common operating philosophies
  - integrated site-wide priorities
  - ~~integrated site-wide procedures~~
  - resource sharing

Business Process Redesign

- **What is Business Process Redesign?**
  - An Enterprise-wide process improvement initiative to assess the way we work and to create more effective work processes.
- **Why Business Process Redesign?**
  - Allow us - the NBU and Enterprise - to achieve our goal of operational excellence.
  - Enhance our emphasis on nuclear safety.
  - Manage our work better.
  - Standardize and streamline disparate systems
  - Control our costs more effectively.

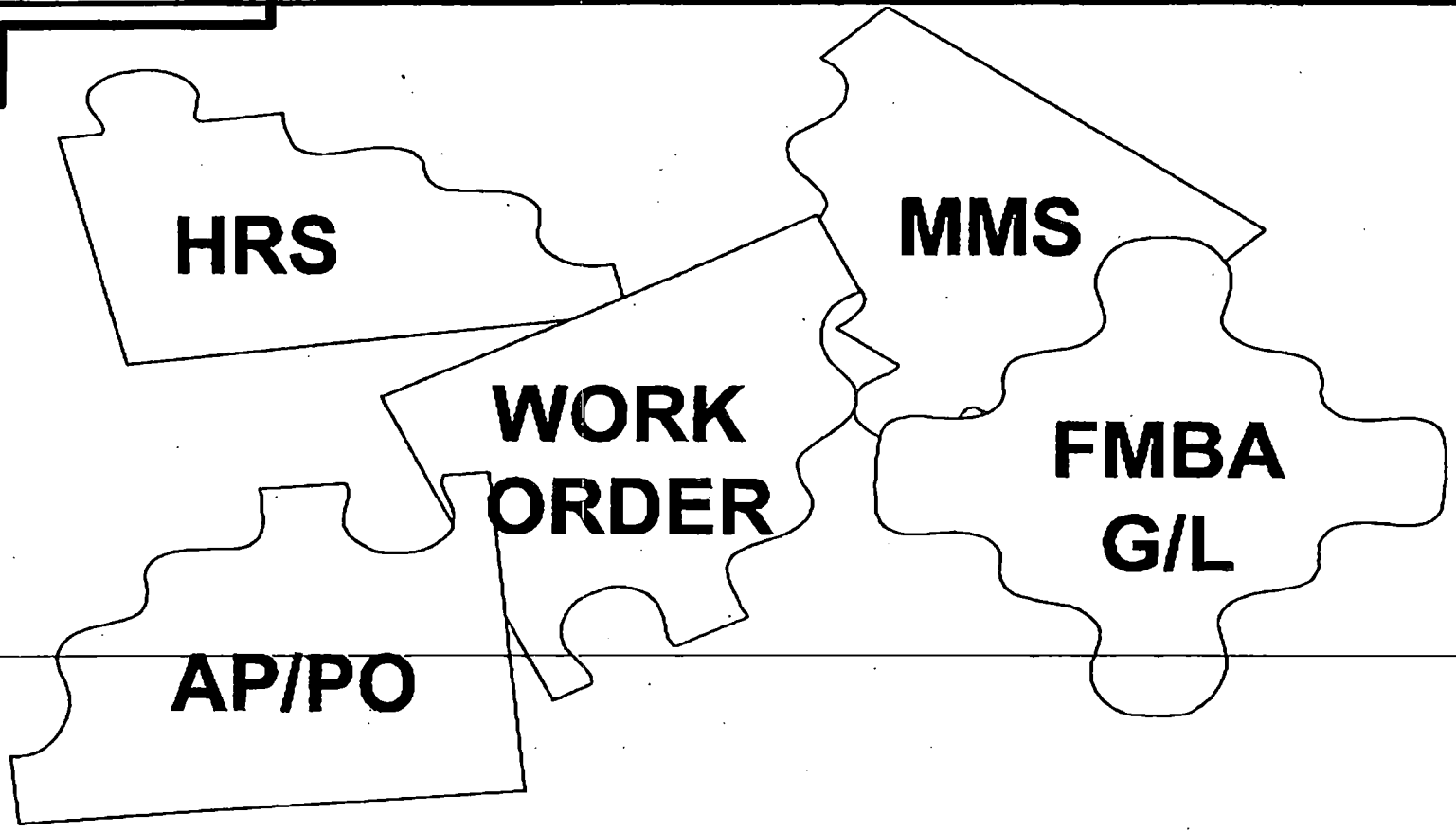
Systems Management Methodology (SMM)



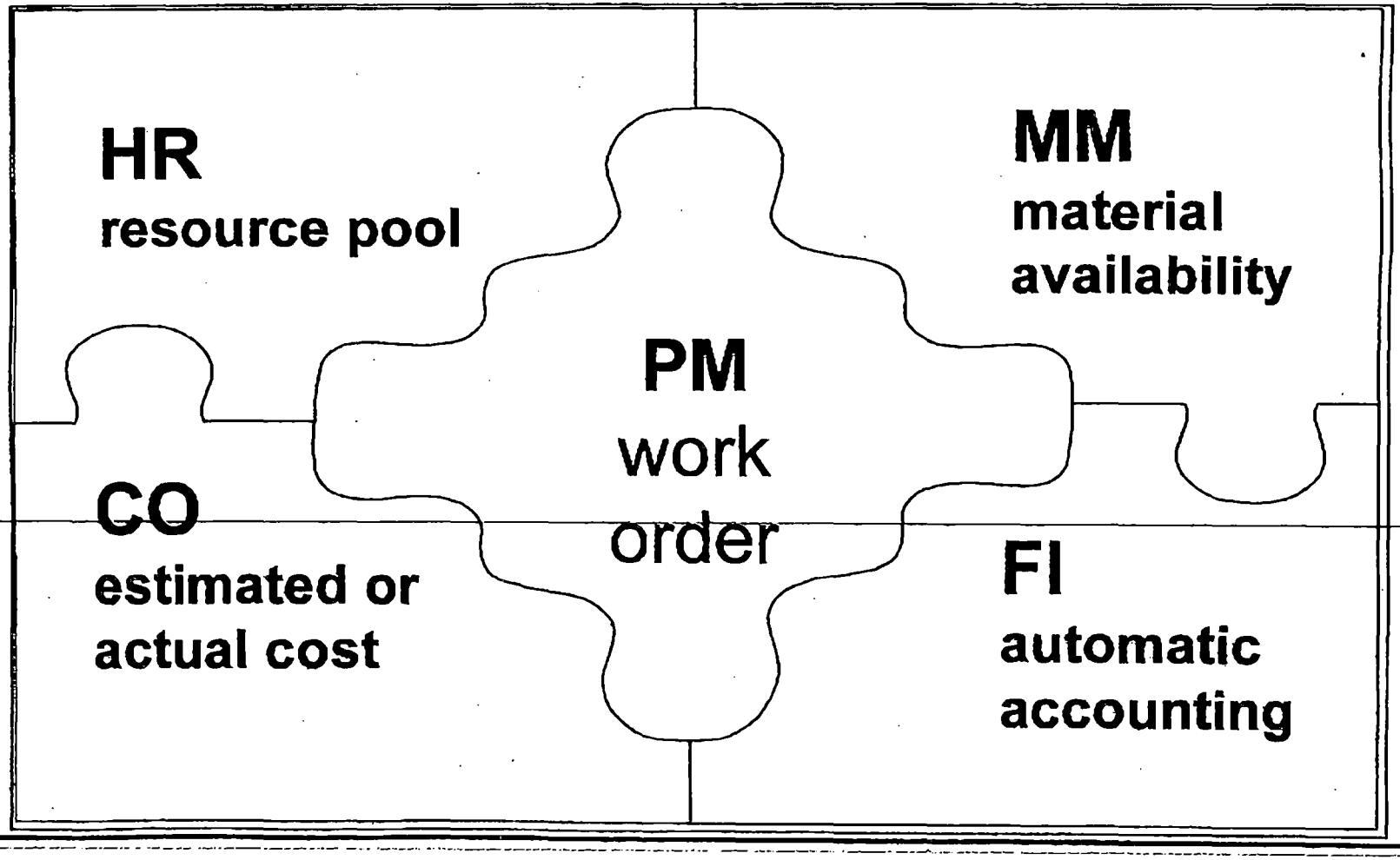
Business Process Redesign

- **What is SAP**
  - SAP is an advanced software tool that will enable us to leverage the power of information through an integrated system?
- **Fully Integrated Modules**
  - Work Management
    - PM/PS (Plant Maintenance/Project Systems)
    - MM (Material Management)
    - WC (Work Clearance)
  - FI/CO (Financial Accounting/Controlling)
  - HR (Human Resources)

Previous Work Management Process



Integrated Work Management Process Utilizing SAP



Business Process Redesign

- **Changing our Business Processes without impacting safety**
  - Focus on our people/culture
    - Using Site Leaders - one of their own/opinion leaders in the organization
    - Communications and Training are key elements
  - Data Conversion
    - Verification and Validation Built In
    - Historical Data will be Archived
    - Challenge - Large Volume of Data

Business Process Redesign

- **Parallel Process Improvements**
  - Work Clearance Module (Tagging)
  - Document Control and Records Management System (DCRMS)
  - Preventive Maintenance Optimization (PMO)
  - Conversion of network and desktop machines to Windows NT
  - Personnel Radiation and Exposure Monitoring System (PREMS to be replaced by PRORAD)
  - Access Control System (INSS)

Business Process Redesign

- **Where are we on Work Management?**
  - "To Be" state designed.
  - Work Management Processes aligned with "To Be" state.
  - Work Management Center (WMC) has been operational since 6/15/98.
  - Focus now on implementation.
  - The new software system (SAP) fully supports the new processes.

Work Management

Identify Work

Plan Work

Schedule Work

Execute Work

Close Work

I P S E C

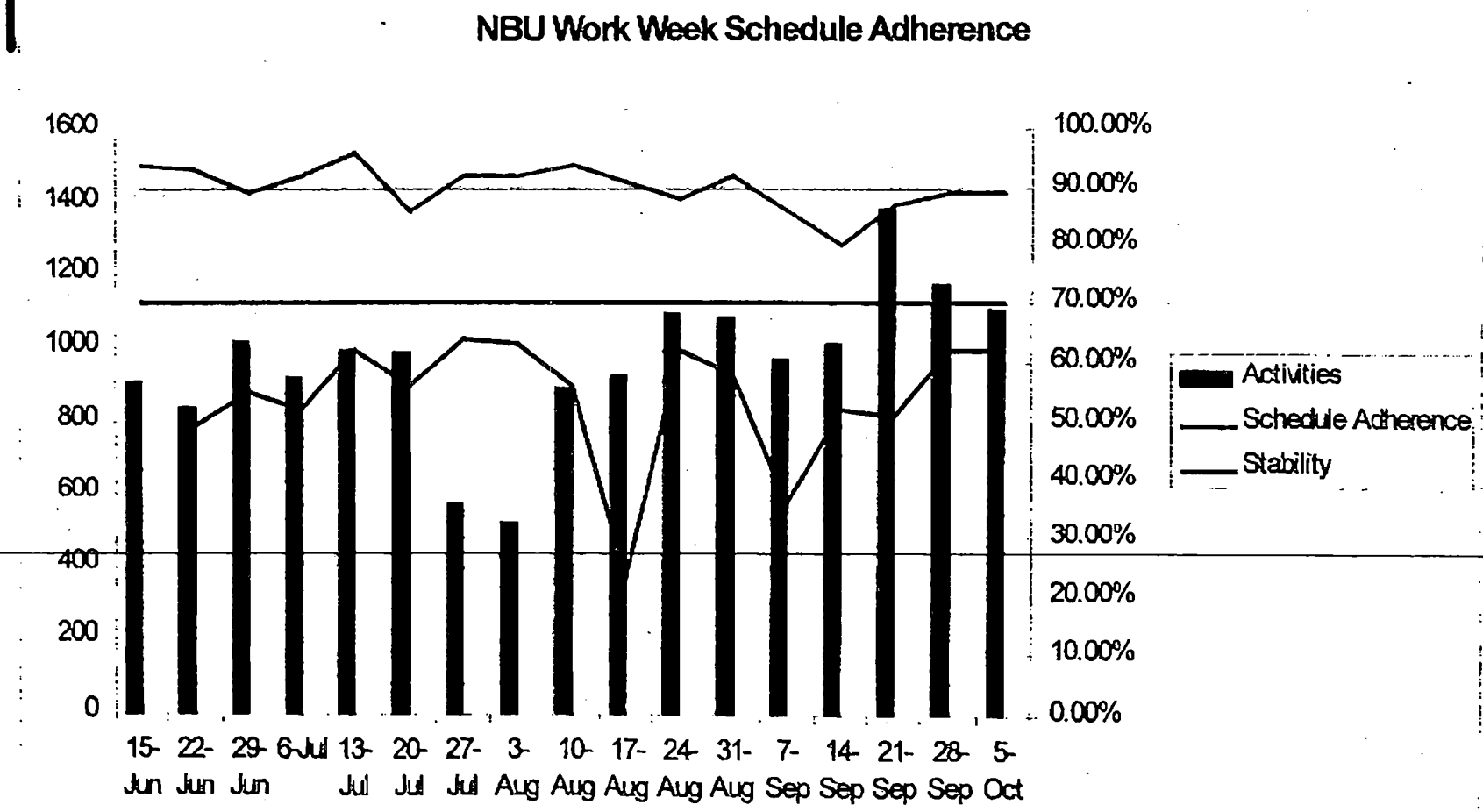
Work Management Examples

PREVIOUS	IN THE FUTURE
Low Initiation Threshold	Low Initiation Threshold
Long Cycle Time	Streamlined Processing (WMC)
Inconsistent/changing priorities	NBU wide priorities (WMC)
Inconsistent processing schemes	Centralized processing (WMC)
Inconsistent WOs	Standardized task lists

Work Management Examples

PREVIOUS	IN THE FUTURE
Poor control of scope expansion	Scope changes directed through WMC
Lost work orders	Continuous traceability on line within SAP
Corrective Actions not prioritized	NBU wide priorities (WMC)
Multiple software systems not designed to communicate	SAP - one, fully integrated system

Work Management Examples



BPR/SAP Implementation Schedule

- **Work Management Processes** (Ongoing)
  - Work Management Center/Work Week Management System - 12 week work schedule
- **SAP Implementation**
  - Human Resources (HR) 12/98
  - Financial/Controlling (FI/CO) 1/99
  - Work Management (PM/PS) 7/99
  - Work Clearance (WC) 7/99
  - Materials Management (MM) 7/99

Challenges

- **Training**
- **Culture Change**
  - Using Site Leaders
- **Data Conversion**
- **Work Clearance Module (Tagging)**
  - Tight schedule with no float.
  - Final version load in 2/99.
  - Two checkpoints this year to ensure current system could be upgraded if required.