U. S. NUCLEAR REGULATORY COMMISSION

REGION I

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Report No.	50-272/96-07, 50-311/96-07
Licensee:	Public Service Electric and Gas Company
Facility:	Salem Nuclear Generating Station, Units 1 & 2
Location:	P.O. Box 236 Hancocks Bridge, New Jersey 08038
Dates:	May 19, 1996 - June 29, 1996
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EXECUTIVE SUMMARY

Salem Inspection Reports 50-272/96-07; 50-311/96-07

May 19, 1996 - June 29, 1996

This integrated inspection included aspects of licensee operations, engineering, maintenance, and plant support. The report covers a 6-week period of resident inspection; in addition, it includes the results of licensing submittal timeliness assessment by the NRR Salem Project Manager, a Salem restart item closeout inspection and a safety related breaker inspection by regional engineering inspectors.

Operations

Overall, operators adequately ensured plant safety during the inspection period. For instance, operators appropriately complied with abnormal and event notification procedures following an ammonia leak in the Unit 2 turbine building basement. (Section 04.3)

In three other instances, however, operators did not demonstrate a thorough questioning attitude. For example, operators did not know the extent or nature of leakage from the Salem Unit 1 spent fuel pool. The operating shift did not establish appropriate compensatory measures until inspector questions prompted these actions. (Section 02.1) When a 13kv breaker failed to close, the senior reactor operator (SRO) did not discover that equipment operators failed to follow procedures in restoring the 13kv switchyard breaker to service. (Section 04.1) Lack of operator attention to control room indication resulted in an attempt to start a fuel handling ventilation fan without control power available. The ineffectual attempt had no safety consequence due to plant conditions. (Section 04.2)

Inspectors observed several indications that PSE&G efforts to improve oversight functions have resulted in improvement. The Salem staff improved the effectiveness of the Operating Experience Feedback (OEF) program through management changes, improved performance monitoring, more effective screening, enhanced communication with the training organization, and revisions to the OEF procedure. The new OEF screening process resulted in improved accountability for implementing corrective actions. The NRC restart inspection item remains open, however, due to inspector identified discrepancies in the OEF procedure. (Section 07.1) During the past year, the Quality Assurance staff completed numerous audits and observations leading to significant findings. The plant staff, however, did not provide a basis to conclude that line management had addressed the findings in a timely and effective manner. As a result, this restart inspection item also remains open. (Section 07.2) The inspectors also noted that, as a result of ineffective management of licensing priorities, PSE&G did not submit three requests for changes to Technical Specifications in a timely manner. (Section 07.3)

(Executive Summary Continued)

Maintenance

Many examples of poor quality maintenance occurred during the inspection period. For example, maintenance staff could not effectively correct long-standing no. 2 station air compressor tripping problems.(Section M1.3) Several problems with maintenance involved failure to adhere to procedures. In one instance, technicians failed to comply with PSE&G work standards and procedure requirements during a service water pump installation. Maintenance managers did not effectively communicate previous similar problems, and, therefore, directly contributed to a repeat occurrence.(Section M3.1) Inspectors identified two examples of procedure use and documentation deficiencies during no. 2A emergency diesel generator turbocharger aftercooler work. Maintenance technicians did not complete procedure steps, within a section, in order, and with supervisor approval they proceeded to another section in the procedure prior to completing the previous section. They did not stop work and change a procedure to reflect the work as performed. (Section M3.2) Senior Reactor Operators failed to thoroughly review emergency diesel generator surveillances. There was no resultant safety consequence due to plant conditions (shutdown and defueled). (Section M3.4) A technician appropriately identified that a work order did not provide adequate control of post-maintenance testing for safety related relays. Although the technician and a planner developed more detailed instructions, they did not ensure the instructions met the Technical Specification 6.8.1.a requirements for procedures to control safety related maintenance.(Section M4.1) In addition, a lack of maintenance support contributed to little progress in the reduction of operator workarounds and control room indicator deficiencies.(Section M1.4)

In response to the poor quality maintenance, the Salem General Manager stopped maintenance activities for a day and a half. The inspectors noted that the Salem managers and NRC inspectors have previously observed poor maintenance on numerous occasions. In this instance, the Salem General Manager implemented substantial changes intended to improve the quality of maintenance. The inspectors noted that managers at the highest levels of the PSE&G Nuclear Business Unit took an active role in supporting and developing the measures to improve maintenance performance. The inspectors also noted that event-free performance of the Salem units requires that equipment reliability be significantly improved prior to Salem Unit 2 restart. (Section M1.2)

Regarding the 4kv circuit breaker inspection, the inspectors found the root cause effort to be extensive and comprehensive. Documentation of troubleshooting, testing, and trips to the vendor site were excellent. Salem's efforts to challenge the vendor for deeper investigation into the root cause and more decisive corrective recommendations was particularly noteworthy. The inspectors concluded that with the exception of consideration of the opening/closing speed of the breakers, the Root Cause Analysis Team (RCAT) appropriately considered the effects of their circuit breaker adjustments on breaker operability and performance. The RCAT performed a thorough analysis and developed far-reaching, comprehensive corrective actions. Relative to the refurbishing and overhaul activities of the electrical switchgear, the inspectors found weakness in Salem's quality

(Executive Summary Continued)

assurance (QA) controls of procurement and vendor interface. The licensee's failure to perform an evaluation of the defect of 4.16 KV circuit breakers or to submit an interim report within 60 days was a violation of 10 CFR 21.21. The cause of this violation indicated a lack of effective communication between the technical personnel and licensing departments, and a failure of station procedures to adequately ensure evaluation of defects for 10 CFR 21 reportability.

Engineering

The inspectors concluded Salem engineers identified and corrected the causes for poor screen motor and controller performance. The system has not yet experienced significant challenge due to the extended plant shutdowns, however, the inspectors considered the substantive component improvements adequate to support reliable system performance. This NRC restart inspection item is closed. (Section E2.1)

A recent discovery of a licensee operating their facility in a manner contrary to the Updated Final Safety Analysis Report (UFSAR) description indicated a need for a special focused review that compares plant practices, procedures, and parameters to the UFSAR description. While performing the inspections discussed in this report, the inspectors noted that plant practices, procedures, and parameters for the spent fuel pool sump pump run alarm differed from the description in the USFAR. This item is unresolved. (Section 02.1)

The efforts to resolve several engineering restart issues were technically acceptable. Therefore, five restart items were closed and three additional items will be closed when the ongoing closure activities are completed. The inspectors found, however, that the licensee's evaluation of spurious high steam flow signals causing safety injection was too narrowly focused. Consequently, the design changes initiated to minimize the impact of these signals may not achieve the desired results. This inspection also identified four unresolved items that require review and attention. The quality of the licensee's restart packages was adequate with improvements noted in packages developed later in the inspection period. These improvements were primarily due to the detailed review of closure packages by the system readiness review committee and by the management review board.

Plant Support

After review of circumstances leading to an ammonia spill, the inspectors concluded plant staff did not comply with the tagging procedure requirements. The procedure non-compliance did not violate regulatory requirements since the work was not a regulated activity. The inspectors noted, however, that plant staff failed to recognize the need to apply red blocking tags to ensure isolation of the ammonia storage tank from open portions of system piping. As a result, they failed to protect other workers in the plant. Had the work involved higher energy systems or safety-related equipment, or if the storage tank isolation valves remained open longer, the staff's inadequate performance

(Executive Summary Continued)

could have resulted in more serious consequences. (Section R1.1)

A security guard did not patrol his assigned area continuously. Security supervision follow up did not thoroughly assess the guard's inattention to duty. They limited the thoroughness of their followup action because of previous good performance of the guard. During the exit meeting, the general manager noted this as a poor practice and provided the proper guidance and direction to the security organization. (Section S4.1)

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Report Details

Summary of Plant Status

Unit 1 and Unit 2 remained defueled for the duration of the inspection period.

I. Operations

01 Conduct of Operations

01.1 General Comments (71707)

Using Inspection Procedure 71707, the inspectors conducted frequent reviews of ongoing plant operations. In general, the conduct of operations was professional and safety-conscious; specific events and noteworthy observations are detailed in the sections below.

02 Operational Status of Facilities and Equipment

02.1 Spent Fuel Pool Liner Leakage, NRC Restart Item III.7 (Open)

a. Inspection Scope (71707)

The inspector conducted frequent tours of the fuel handling building (FHB). Fuel handling building ventilation and spent fuel pool cooling have increased safety significance with both units shutdown and defueled. The inspector discussed tour observations with the operating shift and the system engineering manager. The inspector reviewed Updated Final Safety Analysis Report (UFSAR), section 9.1, Fuel Storage and Handling.

b. Observations and Findings

On May 27, 1996, the inspector toured Unit 1 FHB sump area. The following equipment malfunction information system (EMIS) tags existed: 1) spent fuel pool (SFP) tell-tale no. 1 leaks excessively, dated 11/23/95; 2) FHB sump pump float switch does not start pump, dated 5/12/94; and 3) high level alarm float hangs up on sump cover plate, dated 5/19/96. Simply stated, the spent fuel pool liner may be leaking, the sump pump may not work, and the high level alarm may not alarm. Since equipment operators checked the sump once per day, an increase in leakage could remain undetected for at least one full day.

The Updated Final Safety Analysis Report section 9.1.3.3 states that the FHB sump pump running frequency will be observed through annunciators provided in the control room. The inspector noted that FHB sump high level alarmed on the control room auxiliary typewriter, however, no control room alarm existed for sump pump runs. The sump pump float switch was not configured to provide this alarm. This item is unresolved pending resolution of similar nonconformances with the UFSAR and licensing basis (control air and fuel handling building ventilation). **(URI 50-272&311/96-07-01)** (Also see NRC inspection report 50-272/96-06, Section E2.2)

In response to these concerns, the Senior Nuclear Shift Supervisor (SNSS) promptly generated a Condition Report (CR), CR 960529185, to address these issues. The CR stated that Operations submitted numerous action requests since 1988 identifying problems with the level devices in the Unit 1 FHB sump. The CR requested that engineering evaluate long-standing sump pump and level float switch problems and determine methods to configure the plant in accordance with the UFSAR.

In a followup inspection on May 30, the inspector noted that operating shift did not know the source of tell-tale leakage (SFP leakage or groundwater seepage). After the inspector questioned the boron concentration of the leakage, the SNSS directed chemistry to sample the leakage. The chemistry technician reported a boron concentration of approximately 2400 ppm, indicative of SFP leakage. The inspector subsequently questioned the prudence of continuing the current frequency of equipment operator (OE) sump inspections (once per day) given the degraded conditions. Thus, SNSS directed the Unit 1 EOs to perform sump inspections every four hours. The inspector noted that chemistry last measured tell-tale leakage in November 1995. The inspector questioned the present leak rate. The SNSS directed chemistry to periodically measure the tell-tale leak rate. Chemistry calculated a leak rate approximately equal to the November 1995 rate (400 ml/min).

c. Conclusions

The inspector identified degraded conditions that presented a potential for undetected spent fuel pool leakage that were not well known by the operating shift. Once identified, the shift did not establish appropriate compensatory measures until inspector questions prompted these actions.

O4 Operator Knowledge and Performance

O4.1 Failure to Prepare a 13 kv Breaker for Closure, NRC Restart Item III.7 (Open)

a. Inspection Scope (71707)

During a Unit 2 control room walkdown, the inspector reviewed the reactor operator's narrative log.

b. Observations and Findings

On June 6, 1996, Unit 2 control room operators attempted to close the 13kv bus section D-E breaker. The breaker failed to close because operators had not closed a control power breaker at the D-E breaker. Operators subsequently closed the control power breaker, closed the D-E breaker, and energized no. 23 station power transformer (SPT) to provide a second source of offsite power to the Unit 2 vital buses.

The senior reactor operator (SRO) initiated a procedure revision request to address the open D-E breaker control power breaker without reviewing requirements in the operating procedure. The SRO did not initiate a CR to investigate why the control power breaker was not closed.

In discussion with control room operators, the inspector found that Salem procedure SC.OP-SO.13-0014, Revision 9, *4, 14, and 23 Station Power Transformer Operation*, step 5.3.11, requires equipment operators to close the control power switch after racking up a 13kv breaker. On June 5, 1996, equipment operators racked up the D-E 13kv breaker and failed to close the control power switch. This is a violation of TS 6.8.1 requirements which requires that procedures be adequately implemented. **(VIO 50-272&311/96-07-02)**

The SRO took ineffective corrective action. He initiated a procedure change, but an existing procedure would have ensured the operators closed the control power breaker if operators had implemented it. In response, the Operations manager directed the SNSS to initiate a CR (960606369). Preliminary results indicated that equipment operators did not follow the procedure because they did not know the procedure existed. Equipment operators relied upon skill of the craft, not procedure controls, to restore power sources that provide offsite power sources to the onsite vital buses.

c. Conclusions

The SRO did not demonstrate a questioning attitude in addressing the failure of a 13kv breaker to close. Equipment operators failed to follow procedures in restoring a 13kv switchyard breaker to service. This NRC-identified failure to comply with procedure requirements is a violation.

04.2 Operator Attention to Indications, NRC Restart Item III.7 (Open)

a. Inspection Scope (71707)

Using Inspection Procedure 71707, the inspector conducted frequent control room tours and operating log reviews. In addition, the inspector discussed operator performance with control room operators and operations management.

b. Observations and Findings

On June 4, 1996, Unit 2 control room operators attempted to start no. 22 FHB exhaust fan following a temporary tag release to test the fan. The operator pushed the start button, but the fan failed to start. Operators identified that 28 VDC control power was still tagged out for the fan. The operator could have detected the absence of control power, but he failed to notice that all the normal fan control indicating lights were not lit. Equipment operators restored 28 VDC, the fan started, and the control room operator noticed the fan running six minutes later. Operator inattention contributed to a six minute run rather than the desired five second rotation check. The poor operator performance had no immediate safety consequence since the fan was not required for plant conditions existing at the time.

c. Conclusions

Lack of operator attention to control room indication resulted in an attempt to start a fuel handling ventilation fan without control power available. The ineffectual attempt had no safety consequence due to plant conditions.

04.3 Ammonia Leak, NRC Restart Item III.7 (Open)

a. Inspection Scope

The inspectors observed licensee response to an ammonia leak in the Unit 2 turbine building.

b. Observations and Findings

On June 7, at 9:00 a.m., a worker called the Control Room to report a strong ammonia smell coming from the basement area (88 foot elevation) of the Unit 2 turbine building. The operators entered Abnormal Procedure SC.OP-AB.CR-0003(Q) - REV. 2, *Toxic Gas Release*, and directed all personnel to evacuate the Unit 1 and 2 turbine buildings. At 9:30 a.m., the SNSS declared an Unusual Event in accordance with section 8.A of the Emergency Classification Guide. Operators identified the source of the leak at about 9:35 a.m., and isolated it. At about 11:00 a.m., Site Protection personnel verified the turbine area was free of toxic fumes. The SNSS subsequently terminated the Unusual Event and restored access to the turbine building. No injuries occurred during the event. (Section R1.1 has additional details)

c. Conclusions

Operators complied with abnormal and event notification procedures following the report of an ammonia smell in the Unit 2 turbine building basement. The inspectors concluded the operators responded appropriately.

07 Quality Assurance in Operations

07.1 Adequacy of the Quality Assurance (QA) Program, NRC Restart Inspection Item II.20 (Open)

a. Inspection Scope

Inspectors reviewed QA performance to assess effectiveness of licensee corrective actions.

b. Observations and Findings

The licensee described previous QA performance with the following problem statement: "Prior to the shutting the Salem Units down in 1995, the Salem QA organization did not provide effective oversight. When QA identified problems the line organization did not always address the problems in a timely manner. This resulted in the line organization not getting quality feedback on their performance, and subsequent failure to take effective corrective action."

In response to ineffective QA performance, PSE&G senior management made management changes, organizational changes to provide more meaningful assessments, and program changes. The management changes included a new Director of Quality Assurance and Nuclear Safety Review, a new Salem QA manager, and new direct reports to the QA manager. The new QA management team initiated program changes to improve the quality of QA assessments, with some significantly improved results. For example, an in-service testing (IST) audit determined that the Salem staff had not implemented an effective IST program. The QA staff initiated a stop work order for IST until the plant staff corrected the identified deficiencies.

The QA organization also took ownership for development of the Corrective Action Program (CAP). The CAP includes a graded approach for root caused determinations. A separate NRC restart inspection item addresses the CAP in greater detail.

The inspector noted that the Management Review Committee reviewed and approved the closure package for adequacy of the QA program. This package is intended to provide an adequate basis for concluding that QA effectiveness has improved substantially. It does not, however, address the response of the line organization to problems identified by QA. As a result, this item remains open until the licensee establishes a basis for concluding the line organization responds to QA findings in a timely and effective manner.

c. Conclusions

During the past year, the Quality Assurance staff completed numerous audits and observations leading to significant findings. Examples include the IST audit, with significant findings resulting in a stop work order. The inspector determined, however, that QA did not supply evidence that line management had addressed the QA findings in a timely and effective manner. As a result, this restart inspection item remains open.

07.2 Operating Experience Feedback (OEF) Program, NRC Restart Inspection Item II.9 (Open)

a. Inspection Scope

The inspectors reviewed the results of licensee actions to improve the OEF program.

b. Observations and Findings

Previous inspections concluded that the OEF program did not effectively prevent events that have occurred in the industry from occurring at NBU facilities. In response to the concern about OEF effectiveness, the new OEF manager and the OEF staff improved the OEF screening process and program performance tracking capabilities. They also performed a self-assessment, implemented the resulting recommendations, and enhanced communication with the training organization.

The inspector reviewed a set of comprehensive performance indicators that provide managers the ability to assess staff timeliness in responding to assigned OEF actions. The inspector verified that OEF actions resulted in corrective maintenance, design changes, and procedure changes where appropriate. The Salem staff revised administrative procedure NC.NA-AP.ZZ-0054(Q), *Operating Experience (OE) Program*, to clarify roles, responsibilities, and expectations. Although the revision incorporated numerous clarifications and improvements, the inspector identified that the staff could not provide a clear basis to establish that Salem staff met all of the responsibilities. For example, the staff could not furnish evidence that the General Managers, Hope Creek and Salem Operations had discharged their responsibilities as described in section 3.8 of the procedure. The OEF staff initiated CR 960619251 to address this concern. This item remains open pending resolution of the CR and the resulting corrective action.

C. <u>Conclusions</u>

The Salem staff improved the effectiveness of the OEF program through better performance monitoring, improved screening, enhanced communication with the training organization, and revisions to the OEF procedure. The performance monitoring resulted in greater accountability for implementing corrective actions. The inspector noted, however, that the OEF staff could not furnish evidence that plant staff met all of the responsibilities established in the OEF procedure.

07.3 License Change Request Timeliness

a. <u>Inspection Scope (71707)</u>

The inspectors reviewed three licensing submittals to assess the timeliness of the submittals.

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

On February 1, 1996, PSE&G informed the NRC that they planned to submit proposed amendments to the Technical Specifications for the control room ventilation system to reflect the reconfigured control rooms. On April 2, 1996, the licensee informed the NRC that they planned to submit the proposed amendments on April 12, 1996. The licensee submitted the amendments June 10, 1996, requesting that the NRC approve the amendments by July 22, 1996.

On February 1, 1996, PSE&G informed the NRC they planned to submit proposed amendments to the Technical Specifications for the Reactor Vessel Indication System (RVLIS). On April 2, 1996, PSE&G informed the

NRC that they planned to submit the amendments on April 19, 1996. The licensee submitted the proposed amendments on May 31, 1996, requesting that the NRC approve the amendments by July 15, 1996.

Licensee Event Report (LER) 95-016-0, dated August 18, 1995, discussed a discrepancy between the peak containment temperature in the licensing basis Main Steam Line Break and the maximum containment air temperature in Technical Specification (TS) 5.2.2. In the LER the licensee committed to resolve this issue, as well as the other issues raised in the LER, prior to entry into Mode 4. On June 18, 1996, PSE&G submitted the proposed amendment to TS 5.2.2, requesting NRC approval by July 29, 1996.

c. Conclusions

The inspectors concluded that, as a result of ineffective management of licensing priorities, PSE&G did not submit three requests for changes to Technical Specifications in a timely manner.

II. Maintenance

M1 Conduct of Maintenance

M1.1 General Comments

a. Inspection Scope (62703)

The inspectors observed all or portions of the following activities:

- 960315187: 2B EDG starting air and turbo boost system upgrade
- 960504040: fuel rod ultrasonic (UT) inspection for Salem Unit 2
- 960320206: service water pressure gauges seismic monitoring
- 960224046: 2B EDG inspect/replace relays

The inspectors observed that the plant staff performed the maintenance effectively within the requirements of the station maintenance program.

b. Inspection Scope (61726)

The inspectors observed all or portions of the following surveillances:

- S2.OP-ST.DG-0013: 2B Diesel Generator Endurance Run
- S2.OP-ST.DG-0002: 2B Diesel Generator Surveillance Test
- S2.OP-ST.FHV-0001: Fuel Handling Building Ventilation Surveillance
- S2.OP-ST.RM-0002: Radiation Monitoring Check Sources

The inspectors observed that plant staff did the surveillance safely, effectively proving operability of the associated system.

M1.2 Maintenance Stand-down, NRC Restart Item III.3 (Open)

a. Inspection Scope (71707)

Inspectors reviewed the efforts by Salem managers to improve the quality of maintenance.

b. Observations and Findings

Many lapses in maintenance during a three week period prompted the Salem Maintenance Department to stop work and review the conduct and quality of performance. Salem maintenance managers stopped all work on June 10. The causes for the stop work (identified by Salem staff) included work management process deficiencies, poor scheduling, and procedure non-compliances. The causes also included insufficient supervisory oversight, inadequate shift turnover, a weak sense of ownership and accountability, and worker fatigue. Specific equipment-related maintenance problems included not filling a diesel starting air compressor with oil, turning the no. 2 station air compressor over to operations with numerous discrepancies, work on no. 23 service water pump without a work order present at the job, and installing no. 22 fuel handling building ventilation fan backward and without required washers. Other problems included not performing post-maintenance testing (PMT) for a 4kv supply breaker, and turning valve 2CV71 over to operations with missing linkage.

To correct the poor performance, Salem managers increased the number of supervisors in the field, reviewed work assignments to ensure worker skills matched job requirements, reinforced expectations for quality of workmanship, and assigned PMT coordinators. In addition, the managers planned to re-organize the Salem planning, scheduling, tagging, and maintenance organizations under a single manager reporting to the Salem General Manager. The managers concluded that they required the re-organization to improve coordination, communication, and teamwork within the departments. They also put senior managers in charge of the outage control center (including backshifts).

c. Conclusions

Many examples of poor quality maintenance occurred during the inspection period. In response, the Salem General Manager stopped maintenance activities for a day and a half. The inspectors noted that the Salem managers and NRC inspectors have previously observed poor maintenance on numerous occasions. In this instance, the Salem General Manager implemented substantial changes intended to improve the quality of maintenance. The inspectors noted that managers at the highest levels of the PSE&G Nuclear Business Unit took an active role in supporting and developing the measures to improve maintenance performance. The inspectors also noted that event-free performance of the Salem units requires that equipment reliability be significantly improved prior to Salem Unit 2 restart.

M1.3 Station Air Compressor Repair, NRC Restart Item III.11 and II.2 (Open)

a. Inspection Scope (92903)

The inspector observed no. 2 station air compressor maintenance to assess station air reliability.

b. Observations and Findings

On April 25, 1996, no. 2 station air compressor (SAC) tripped on high vibration. The system manager initiated actions to investigate the frequent no. 2 SAC trips.

On May 31, equipment operators prepared to rack up the no. 2 SAC breaker for a decoupled motor run. Equipment operators discovered that electricians had not installed the breaker in the cubicle. Electricians installed a replacement breaker and operators attempted to start the SAC, however, the compressor did not start. Electricians discovered that they had installed permissive start jumpers (used for rotation checks when decoupled) in the no. 3 SAC instead of the no. 2 SAC. (Electricians had installed the jumpers in no. 3 SAC in April 1996 due an inadequate procedure.)

On June 1, electricians installed jumpers in the no. 2 SAC control cabinet. The operators attempted to start the no. 2 SAC and it tripped on high vibration. On June 2, operators started the no. 2 SAC. After two minutes the SAC tripped on low cooling water pressure. Maintenance staff determined that the SAC needed a service water low pressure permissive jumper.

During the above process, maintenance staff experienced other minor setbacks involving control panel relays and annunciators. On June 2, maintenance managers stopped no. 2 SAC work due to the above series of maintenance-related difficulties (see maintenance stand-down in section M1.2).

Following the June 2 work stoppage, maintenance managers tasked a special SAC troubleshooting team to restore the no. 2 SAC to service. The team met with limited success to date. On June 6, the SAC tripped on high vibration on start. On June 14, maintenance staff believed they corrected previous problems and requested that operators start the SAC for dynamic tuning. On June 14, operators started the no. 2 SAC and the compressor tripped on high vibration.

c. Conclusions

Maintenance efforts to correct long-standing no. 2 station air compressor tripping problems have been ineffective. Performance results in this area indicate a lack of quality and reliability in maintenance practices.

M1.4 Operator Workarounds and Control Room Deficiencies, NRC Restart Item III.8 (Open)

a. Inspection Scope (71707)

The inspector discussed operator workarounds and control room indicator status with Operations management.

b. Observations and Findings

The Operations Restart Plan addressed the need to eliminate operator workarounds and control room indicator (CRI) deficiencies. Operator workarounds represent degraded plant conditions that substitute operator action for the normal operation of structures, systems and components

In mid-March 1996, the Operations manager assigned a workaround manager to provide full time oversight and control of the workaround and CRI deficiency list. Plant staff continued to make little progress in this area, since the number of new items added to the list nearly offset the limited number of items worked.

The workaround manager implemented an effective tracking program. The manager methodically developed and improved activity prioritization. The trends indicated a very high reschedule rate and a relatively low work completion rate.

Operations and Planning managers supported this effort. The maintenance staff, however, rescheduled a majority of their activities in this area. The inspector concluded that maintenance managers placed a low priority on operator workarounds.

c. Conclusions

A lack of maintenance support contributed to little progress in the reduction of operator workarounds and control room indicator deficiencies.

M1.5 Review of General Electric Circuit Breaker Failures

a. Inspection Scope (62705)

The purpose of this inspection was to evaluate the root cause, the corrective actions, and the generic implications of the recent problems experienced with General Electric (GE) Magne-Blast 4.16kV circuit breakers. Specifically, the inspectors reviewed the following areas:

- root cause analysis
- corrective actions
- procurement process for initial purchase of the breakers

- procurement process for subsequent maintenance and overhaul services
- reportability requirements

M1.5.1 **Root Cause Analysis**

a. Inspection Scope

The inspectors examined the efforts of the Root Cause Analysis Team (RCAT). The inspectors reviewed the final report, trip reports, testing summaries, and operating experience reports.

b. Observations and Findings

Summary of 4.16 kV Circuit Breaker Problems

There are approximately 144, type AM-4.16kV, Magne-Blast General Electric circuit breakers installed at Salem Electric Generating Station, Units 1 & 2. At Salem, all breakers are considered safety-related because they can be used in safety-related and nonsafety-related applications. Therefore, a breaker operating in a nonsafety-related cubicle can be inserted into a safety-related cubicle. Salem also uses 13.8-kV, GE Magne-Blast circuit breakers; these are in nonsafety-related applications. Both, the 4.16kV and 13.8kV circuit breakers employ ML-13 operating mechanisms.

Starting from January 1996, Salem experienced 4.16kV circuit breakers failing to latch closed and remain closed upon a close signal. This problem affects the following vertical lift circuit breakers with ML-13 mechanism which have a close and latch ratings of 77kA or above:

4.16kV-250MVA-8, -9HB	4.16KV-350MVA-2H
7.2KV-500MVA-6HB	13.8KV-1000MVA-3, -4H
13.8KV-750MVA-5, -6HB	

At Salem, the first observed failure occurred on January 5, 1996, when the 4.16kV breaker operating the 15 service water pump failed to latch closed. In the following ten weeks, four additional breakers also failed to latch closed upon a close signal.

Salem established a root cause analysis team (RCAT) to determine the root cause of the five circuit breakers which had failed to latch closed. The RCAT established administrative measures so that any breaker that fails to latch is not repeatedly cycled thereby retaining most of the attributes which may have caused the problem. The RCAT has prepared Condition Report PR #960315194 which described the root cause analysis.

4.16-kV, Magne-Blast, Circuit Breaker Failure Mechanism

After extensive testing of the failed breakers, the RCAT determined that the following conditions prevented the breaker to close and remain closed. The prop pin in the ML-13 mechanism failed to achieve the required position under the prop and caused the latching mechanism prop to hit the prop pin. The impact of the prop hitting the prop pin caused the prop to bounce out of its position. This sometimes results in the leading edges of the prop being chipped and flatten. The failure of the prop pin to achieve the required position under the prop may have been due to misalignment, which causes the latching mechanism prop to impact the prop pin and the prop to bounce out of position (see Attachment).

Root Cause of Failures

The inspectors determined several contributing factors causing the failure of the 4.16kV circuit breakers, namely, the alignment of the stationary cubicles and stacked tolerances.

The 4.16kV stationary cubicles may not have been aligned correctly during the construction of the plant. Also, all circuit breakers are treated as safety-related and are interchanged in stationary cubicles. When a circuit breaker is inserted into a cubicle, adjustments are made to align the breaker so that it can operate successfully. When the same breaker is placed in another cubicle, it should be realigned to suit that current stationary cubicle. The adjustments made to the breaker may have induced stresses in both the cubicle and the circuit breaker.

Salem routinely sent breakers to GE Nuclear Energy's Apparatus Service Center for maintenance and repair. During previous refurbishment activities, errors may have been introduced in the alignment of the operating mechanism causing the prop to twist. Additionally, the prop spring pulls the prop on the left hand side and the prop stop pin restricts movement of the prop on the right hand side aggravating the twist.

Symptoms of Failure

To help prevent similar breaker failures, the RCAT has developed the following list of symptoms to ascertain if the breaker is susceptible to the failing to latch closed problem.

- Ensure the prop stop pin is in the fully forward position in the inspection window when the breaker is in the closed position.
- Examine leading edges of the prop through the inspection windows to see if prop is chipped or has a flat surface on the tip.
- Review the history of the breaker to determine if it failed to latch closed on previous occasions.
- Determine if the arcing contacts overstroke by observing if the tips of the contacts have been damaged by their impact on the dividers in the stationary contacts.
- Examine the buffer blocks for cracks and chips.

c. Conclusions

The inspectors found the root cause effort to be extensive and comprehensive. Documentation of the RCAT troubleshooting, testing, and trips to the vendor sight was excellent. Salem's efforts to challenge the vendor for deeper investigation into the root cause and more decisive corrective recommendations was particularly noteworthy.

M1.5.2 Corrective Action for 4.16-kV Switchgear

a. Inspection Scope

The inspectors reviewed the root cause analysis, the associated corrective actions, and vendor (General Electric) recommendations to evaluate the appropriateness of returning the breakers to service.

b. Observations and Findings

The RCAT has taken a number of corrective actions to ensure breaker operability and to return breakers to service.

Salem has contracted GE to inspect and adjust the stationary cubicles. Salem intends to check cubicle misalignment from front to back by oil wipes on bottle inserts (bushings). GE previously checked the wipe height on the bottles but did not compare the contact wipes from the front to back.

The RCAT developed a data sheet of mechanism and frame dimensions and required all breakers that have been serviced to meet this criteria.

Salem conducted the following tests and adjusted every breaker before releasing it for operation.

- operate the breaker several times
- observe if the breakers exhibits any of the symptoms as described above in Section M1.5.1
- verify crank shaft end play - The outboard cranks on the crankshaft should be adjusted so the end play side is less than 0.15 inch. After this adjustment is made, the clearance of the prop pin to the frame should be a minimum of 0.25 inch.
- verify that the minimum distance between the prop pin and the prop before the prop pin changes direction as follows:
    - The minimum distance between either side of the prop and the prop pin is 0.06 inch.

- The maximum difference between one side and the other is 0.032 inch.
- The average of the two shall be within 0.06 to 0.115 inch.

If the above clearances cannot be attained, Salem adjusts the tension on the opening spring as required. Changing the opening spring tension will load the closing spring action and thus reduce the closing speed of the breaker. A change of 1/4" corresponds to approximately a few milliseconds in closing time. The nominal specification for the opening spring is 7 1/4"; GE approved adjustments up to 6 15/16" for Salem.

The licensee tests a breaker after making all adjustments to confirm that it operates successfully without tripping, and captures the motion of the mechanism on film to obtain GE concurrence for breaker operability.

Changing the preload on the opening spring will change the breaker opening time. Even though Salem measured the breaker contact opening time, this value cannot be compared with GE closing and opening speed requirements because measurement methodology is different. Although the licensee had considered the effect of this adjustment on overall closing time, GE has a requirement for the minimum closing and opening speed of the arcing contact. Additional testing and analysis will ensure that the adjustments will not put the breakers out of specification. This will be an inspector follow-up item until such testing and analysis can be performed. **(IFI 50-272&311/96-07-03)**

The RCAT recommended corrective actions to address this concern and the licensee committed to evaluating the concern prior to restart.

The GE proposed corrective action was a combination of (1) replacing the current prop spring with a stiffer one, (2) installing a stop pin to restrict the prop movement on the left hand side, and (3) adjusting the compression on the main contacts. This solution was different from the Salem corrective action. Salem could not implement the GE solution because GE has not tested their fix and does not have the replacement parts manufactured at this time. GE approved the corrective action taken by Salem based on observation of tests conducted on the breakers, and based on viewing the prop movement which Salem captured on film with a high speed camera. Salem has committed to not return any breakers to operable status without GE concurrence that the adjustment program and methodology is acceptable.

c. <u>Conclusions</u>

The inspectors concluded that with the exception of consideration of the opening/closing speed of the breakers, the RCAT appropriately considered the effects of their adjustments on breaker operability and performance. The inspectors concluded that the RCAT performed a thorough analysis and developed far-reaching, comprehensive corrective actions.

M1.5.3 Control of Procurement and Vendor Interface

a. Inspection Scope

The inspectors reviewed purchase order E157777 dated December 3, 1969, issued by PSE&G to GE and associated documents to evaluate the licensee's process for purchasing components to be installed in safety-related applications before 10 CFR Appendix B was in effect. The inspectors also reviewed purchase order 1069619614600000 dated April 4, 1996, issued by PSE&G to GE to refurbish type AM-4.16kV, 350-1200 A and 2000 A circuit breakers.

b. Observations and Findings

Although the original circuit breakers were purchased before 10 CFR 50, Appendix B was in effect, the inspectors noted evidence that the licensee exercised some quality assurance controls in the purchase and maintenance of these components. Inspections had been performed at the manufacturing facility and overhaul facility. Also, a seismic analysis had been performed by General Electric to ensure operability of the switchgear for operation basis and design basis earthquakes.

Purchase order 1069619614600000 referenced a GE proposal, letter G-KT-4-030, dated February 9, 1994, which detailed the work included in overhaul and repair of GE type AM-4.16kV circuit breakers. The refurbishment was to include labor, tooling, test equipment, engineering and Quality Assurance personnel. For Class 1E material, 10 CFR Part 21, 10 CFR Part 50, Appendix B and IEEE Standards were applicable as interpreted by GE Nuclear Energy.

In the proposal, GE requested PSE&G to identify a cognizant individual to interface with GE on all applicable matters. Upon contract award, GE was to identify a single-point contact responsible for interface applicable to this work. Salem identified a planner to interface with GE. Salem's planner gave verbal instructions to GE which Salem's quality assurance personnel could not readily verify when they conducted vendor surveillances.

The purchase order scope described an overhaul procedure for circuit breakers and yet preventive maintenance and corrective maintenance were often performed instead of a complete overhaul. When inspectors asked how the vender knows what specific work to perform on a particular breaker, both Salem procurement and GE replied that the vendor performed the work described in the purchase order. However, the purchase order did not describe the differences between a preventive maintenance activity, corrective maintenance activity and a overhaul. Apparently, the specific work to be performed by the vendor was negotiated between the PSE&G planner and GE personnel via informal, undocumented telephone communications.

c. Conclusions

Based on a review of the original procurement documents, the inspectors determined that the circuit breakers were adequately qualified to perform their intended safety-related functions.

Relative to the refurbishing and overhaul activities of the electrical switchgear, the inspectors found Salem's quality assurance (QA) controls on the procurement and vendor interface to be weak. Discussions with the QA and procurement engineering personnel indicated that they did not know the difference between breaker preventive maintenance and overhaul. The purchase order had a broad scope that required typical overhaul-like actions by the service contractor and yet sometimes the service contractor only performed an abbreviated version of this scope. This lack of vendor control may contribute to configuration control problems and breaker maintenance traceability problems. The licensee had initiated corrective actions, CRCA 22 and CRCA 24 of Performance Improvement Request Number 00960315194, to address these concerns. Although the purchase order only contained vague instructions as to the scope of work to be performed, upon completion of breaker servicing, GE supplied a product quality certification which consisted of detailed documentation of the inspection, repair, and testing performed on the individual breaker.

M1.5.4 Reportability Requirements

a. Inspection Scope

The inspectors examined the licensee's reporting process for compliance with the requirements of 10 CFR 21. This regulation requires evaluation of deviations and failures to comply to identify defects and failures to comply associated with substantial safety hazards as soon as practical, and in all cases within 60 days of discovery.

b. Observations and Findings

On March 14, 1996, the RCAT prepared a document describing the six recent failures of 4.16 KV circuit breakers to remain close following a closed signal, Attachment 5 of the RCAT final report. This document clearly described the failure to remain close to be due to the insufficient timing of alignment between the prop pin and the prop.

On March 15, 1996, Salem published an industry report which detailed that three of the six failed breakers were installed in safety-related applications and had been overhauled by the manufacturer within the last 18 months. The inspector considered this date to be the discovery date since the documentation identifed the existence of a deviation potentially associated with a substantial safety hazard.

Overhaul procurement documents (Special Process Control Sheet of the Product Quality Certification for Purchase Order P106961961460) required satisfactory operation of the circuit breaker to trip closed. The failure of the breaker to latch closed upon a trip signal constitutes a deviation from this technical requirement.

On March 18, 1996, a request was made to evaluate reportability under 10 CFR 50.59, 50.72, and 50.73, to licensing. On May 1, 1996, licensing initially determined that the failures were not reportable.

By March 21, 1996, all installed safety-related 4.16 KV breakers that are normally in the closed position had been inspected to ensure that their prop pins were full forward due to the engineering department's concern about the generic nature of the failure mechanism.

On May 21, 1996, Form 1 from Nuclear Administrative Procedure NC.NA-AP.ZZ-0035(Q) - Revision 5, "Nuclear Licensing and Reporting", was initiated to begin the 10 CFR 21 evaluation process. Form 1 identified the components in question as being necessary to assure the capability to shutdown/maintain shutdown of the reactor and necessary to prevent accidents or to mitigate the consequences of accidents. The completed form also identified the breakers as having a potential defect and a potential noncompliance. However, the initiation of this form was greater than 60 days from discovery and no report was submitted under 10 CFR 21, 10 CFR 50.72, or 10 CFR 50.73 within 60 days of discovery. This was violation of 10 CFR 21.21. **(VIO 50-272&311/96-07-04).**

Upon being unsure about completing the evaluation within 60 days, the regulation allows for filing an interim report until the evaluation can be completed. The licensee did not submit an interim report.

Upon receipt of the Form 1 and the final root cause report dated May 30, 1996, licensing decided to reconsider their original reportability determination and again chose not to perform a 10 CFR 21 evaluation. On June 27, 1996, the licensee submitted a four-hour report under 10 CFR 50.72(b)(2)(iii)(A) and on May 30, 1996, the licensee submitted a Licensee Event Report under 50.73(a)(2)(v).

The inspectors concerns were that there was a lack of communication between the technical personnel involved in the root cause and licensing in that the technical personnel had a clear understanding of the serious nature of the problem and an understanding of the failure mechanism of the basic component and yet licensing based their reporting decision on limited information. This lack of communication and licensing's willingness to wait for a completed, signed-off root cause report (that can take 5-6 months in some cases), resulted in inadequate timeliness for reporting requirements.

The inspectors were also concerned that plant procedures and processes may have contributed to the inadequate reporting of the defect of the 4.16 KV breakers. The corrective action program automatically generated a reportability determination for 10 CFR 50.59, 50.72, and 50.73 upon the initiation of a Significance Level 1 Action Request. However, no automatic reportability determination is made for 10 CFR 21.

Also, Procedure NC.LR-AP.ZZ-0006(Q) - Rev. 0, "10 CFR 21 Evaluation and Reporting," Section 5.4.2 defines "Discovery" as the date that the Manager - Licensing and Regulation concurs that the concern is potentially reportable under 10 CFR 21, whereas 10 CFR 21.3 defines discovery as "the completion of the documentation first identifying the existence of a deviation or failure to comply potentially associated with a substantial safety hazard." The difference between these two definitions may create confusion to plant personnel in determining 10 CFR 21 reporting requirements.

c. Conclusions

The inspectors concluded that the licensee's failure to perform an evaluation of the defect of 4.16 KV circuit breakers or to submit an interim report within 60 days was a violation of 10 CFR 21.21. This violation indicated a lack of communication between the engineering and licensing organizations, as well as a failure of station procedures to adequately ensure evaluation of defects for 10 CFR 21 reportability.

M3 Maintenance Procedures and Documentation

M3.1 Service Water Pump Installation NRC Restart Item III.3 (Open)

a. Inspection Scope (62703)

The inspector observed work in progress and reviewed the work packages and associated procedures for work order 950426206. The inspector discussed the activity with maintenance technicians, supervisors, and managers.

b. Observations and Findings

On May 31, 1996, the inspector observed work on the no. 23 service water pump. The technicians did not maintain the work order at the job site as stated in the Salem Work Standards Handbook.

The inspector reviewed SC.MD-EU.SW-0002, Revision 5, *Johnston Service Water Pump Removal and Installation*. Technicians incorrectly marked step 5.1.1 not applicable (N/A), although the step was required to document supervisor review of prerequisites, precautions and limitations prior to the start of the job. The inspector verified, by technician signature, that technicians had performed the pre-job requirements. Technicians marked additional steps N/A without providing justification in the comments section of the procedure, as required by NC.NA-AP.ZZ-0001 (Revision 7), *Nuclear Procedure System Requirements*. This is another example of a violation of TS 6.8.1 requirements to implement procedures for control of safety-related activities (see section 04.1).

The procedure violation is a repeat of a May 2, 1996, violation (see NRC Open Item 50-272&311/96-06-01). The inspector discovered that the site services division of the maintenance department did not receive the May

2 lessons-learned training provided to other members of the maintenance department.

The inspector also noted that technicians did not perform steps specified by SC.MD-EU.SW-0002 in the required sequence. Step 5.3.20 required installation of a Maloney kit (anti-corrosion sleeves for fasteners) and pump discharge flange fasteners. The technicians stated that they could not complete the step in proper sequence because the Maloney kit, 8 studs and 16 nuts were missing. They obtained identical studs and nuts from another service water pump package and temporarily installed the discharge flange without installing a Maloney kit. The inspector considered the partial completion of step 5.3.20 acceptable since the technicians needed to immediately install the flange to prevent service water bay flooding on the incoming tide. Technicians planned to pull one stud at a time to install the Maloney kit when it became available. The inspector considered this a reasonable approach to avoid service water bay flooding, but noted that no procedure controls existed for this process. In this case, no safety consequence resulted from the technicians not following procedures or insuring that they obtained all parts necessary to perform a time-critical task prior to starting the job.

The inspector discussed the performance problems with Unit 2 senior maintenance manager. He promptly stopped work on the no. 23 service water pump until the maintenance supervisor reviewed and adhered to the required procedures. Maintenance managers conducted a roll-down meeting with all personnel in the group to communicate circumstances of the problem, and to emphasize the importance of adherence to work standards and compliance with procedure requirements.

c. Conclusions

Maintenance technicians failed to comply with PSE&G work standards and procedure requirements during the conduct of service water pump installation. Failure to effectively communicate past shortcomings in this area directly contributed to this repeat occurrence. This NRC-identified failure to comply with procedure requirements is a violation.

M3.2 Emergency Diesel Generator (EDG) Turbocharger Aftercooler Cleaning and Inspection

a. Inspection Scope (62703)

The inspector reviewed the work package and associated procedure for work order 950824191. The inspector discussed this activity with maintenance technicians, supervisors, and managers.

b. Observations and Findings

On June 26, 1996, the inspector observed work in progress on the 2A EDG. The inspector reviewed SC.MD-PM.DG-0002(Q), Revision 4, *Diesel Generator Turbocharger Aftercooler Cleaning and Inspection*. The inspector noted that technicians completed steps 5.2.14 through 5.2.17 prior to completion of step 5.2.13 steps in section 5.2 Removal/Disassembly. The inspector also noted that the technicians proceeded to section 5.4 Reassembly/Installation, prior to completing all the steps in section 5.2, without appropriate documentation. The technicians obtained supervisor approval to perform the steps out of order, however, they made no effort to revise the procedure to reflect the manner in which they actually performed the work.

Nuclear Administrative Procedure, NC.NA-AP.ZZ-0001(Q), *Nuclear Procedure System* (NAP-1), Revision 7, Section 5.3.7.D, requires that steps identified with numbers or letters (e.g., 5.1.2 or 5.1.2.A) should be completed in order unless the procedure allows otherwise. Salem common procedure SC.MD-PM.DG-0002(Q), Revision 4, *Diesel Generator Turbocharger Aftercooler Cleaning and Inspection*, step 3.11, requires that applicable steps within a procedure should be completed prior to starting the next section. Failure to perform the procedure steps and sections in sequence are additional examples of violation of NC.NA-AP.ZZ-0001(Q), *Nuclear Procedure System* (Revision 7), requirements. The inspectors concluded that performing the procedure steps out of order had no immediate safety consequence, since technicians completed the missed actions prior to restoration of the EDG.

c. Conclusion

The inspector identified two examples of procedure use and documentation deficiencies. Technicians performing work on the turbocharger aftercooler did not complete the steps within a section in order, and, with supervisor approval, the technicians proceeded to another section in the procedure prior to completing the previous section. They did not stop work and change the procedure to reflect the work as performed.

M3.3 Fuel Handling Building Ventilation, NRC Restart Item III.3 (Open)

a. Inspection Scope (61726)

In preparation for fuel movement, the inspector reviewed SC.RP-ST.FHV-1140, Revision 0, *Fuel Handling Building Ventilation System Negative Pressure Test*. The inspector discussed observations with Radiation Protection management.

b. Observations and Findings

On June 5, 1996, the inspector reviewed SC.RPST.FHV-1140. The inspector discovered an improperly calculated average pressure reading. The inspector also found that technicians did not perform an independent verification of the calculations as required by step 5.2.7 of SC.RP-ST.FHV-1140. In developing the procedure, Radiation Protection (RP) staff assigned a procedure use category that did not require use of the procedure in the field nor individual step documentation. The inspector determined that the RP staff chose an inadequate procedure use classification since they performed the surveillance infrequently (every refueling outage) and the procedure required documentation of equipment performance necessary to prove operability, as specified in Technical Specification 4.9.12.d.3. Licensee procedure NC.NA-AP.ZZ-0001 (Revision 7), *Nuclear Procedure System*, attachment 3 requires use categories be assigned based on the importance of documentation and sequential performance of procedural steps with regard to personnel and equipment safety and to safe plant operation. Lack of a required independent verification and improper procedure use classification are additional examples of failure to comply with procedures, as required by TS 6.8.1. (see section 04.1).

Radiation Protection management took prompt and appropriate action to address the deficiencies. They broadened the scope of their investigation to include all RP owned Technical Specification surveillance procedures. The review identified other incorrect calculations in past surveillances and similar procedure use category inadequacies. The RP technicians initiated a process to improve the quality of RP surveillance procedures, including upgrading the procedure use category.

The inspector noted that the miscalculation in SC.RP-ST.FHV-1140 and RP identified miscalculations did not affect previous satisfactory surveillance determinations.

c. Conclusions

An RP technician failed to perform an independent verification of calculations as required by a fuel handling building surveillance. This NRC-identified failure to comply with procedure requirements is a violation. Radiation Protection management took corrective action intended to identify and correct similar deficiencies in all RP sponsored Technical Specification surveillance procedures.

M3.4 Emergency Diesel Generator Operability, NRC Restart Item III.3 (Open)

a. Inspection Scope (61726)

The inspector reviewed the results of EDG surveillances.

b. Observations and Findings

On June 11, 1996, the inspector reviewed S2.OP-ST.DG-0001, Revision 19, *2A Diesel Generator Surveillance Test*. The inspector noted that the equipment operator marked a required diesel fuel oil day tank check for accumulated water N/A. The SRO reviewed the EDG surveillance without questioning the equipment operator about the meaning of N/A. The inspector determined that the equipment operator had performed the required check and the surveillance satisfactory.

The inspector also reviewed S2.OP-ST.DG-0003, Revision 21, *2C Diesel Generator Surveillance Test*. The no. 21 diesel fuel oil storage tank level (DFOST) did not meet the criteria specified on the restoration checklist. The equipment operator annotated this fact in the comments section of the surveillance with a reference from the restoration checklist. The SRO reviewed the EDG surveillance and declared the surveillance satisfactory without documenting how the no. 21 DFOST met the criteria as specified in the procedure. There was no resultant safety consequence due to plant conditions (shutdown and defueled). The inspector noted that operators used a mode 6 EDG operability surveillance to verify an undefined mode EDG availability determination.

c. Conclusions

Senior Reactor Operators failed to thoroughly review emergency diesel generator surveillances. There was no resultant safety consequence due to plant conditions (shutdown and defueled).

M4 Maintenance Staff Knowledge and Performance

M4.1 Use of Procedures for Post Maintenance Testing (PMT)

a. Inspection Scope (62703)

The inspector reviewed PMT for relay installation on the no. 2B EDG to ensure that plant staff implemented required procedures and controls.

b. Observations and Findings

On June 13 an Instrumentation and Controls (I&C) technician noted that work order (WO) 960224046 required PMT for relays replaced on the no. 2B EDG. He also noted that the WO did not provide adequate guidance for a complicated task. The technician worked with a planner to develop a twenty-eight step PMT. They added to steps to the work order "D" page, and the technician successfully performed the post-maintenance test. The instructions required the technician to open and shut 24 VDC and 125 VDC circuit breakers. It also required him to install and remove jumpers. The inspector noted that Salem uses the "D" page to provide general information to workers. The work control procedure does not require review and approval of the "D" page equivalent to the review and approval for safety related procedures. Failure to develop and implement a procedure to control safety related post-maintenance testing is an additional example of failure to comply with procedures, as required by TS 6.8.1. (see section 04.1).

c. Conclusions

A technician appropriately identified that work order 9602254046 did not provide adequate control of post-maintenance testing for safety related relays. Although the technician and a planner developed more detailed instructions, they did not ensure the instructions met the Technical Specification 6.8.1.a requirements for procedures to control safety related maintenance.

III. Engineering

E2 Engineering Support of Facilities and Equipment

E2.1 NRC Restart Issue T3 - Circulating Water Traveling Screen Motor Reliability (Closed) Engineering Restart Action Plan (Open)

a. Inspection Scope

Newly installed circulating water traveling screen motors did not exhibit reliable operation. Also, the control circuits for the screens did not perform reliably.

b. Observations and Findings

Salem engineers determined poor workmanship during initial motor construction, aggravated by the compact design of the motor, caused the motor failures. They determined the causes for control circuit failures were: misadjusted, corroded, or fouled limit switches for the automatic spray control valves; and an inadequate procedure for calibrating the speed control bistables.

Design engineers revised the motor specifications and required a substantially more rugged and conservative design. The new motors have a larger than standard frame size, a new requirement for limiting casing heat rise, a new requirement for end turn windings to be insulated to eliminate winding cross-overs, and a higher insulation rating. The vendor tested the new motors under loaded conditions while measuring parameters such as motor speed, torque, horsepower, full load amps, and motor temperature rise. The new motors met or exceeded all specified criteria. The inspector reviewed test data and noted that, for normal screen speed, the temperature rise for the new motors was about 21 degrees Fahrenheit compared with the failed motors that experienced nearly a 250-degree rise. Also, the amperage draw on the new, more efficient motors was about 80% of the nameplate rating at slow speed compared with 95% to 110% of nameplate for the failed motors.

Salem personnel replaced the automatic spray valves with manual, normally-open spray valves, eliminating all limit switch and speed interlocks. The water demand for the consequential continuous spray is within the capacity of the spray wash pumps. Personnel also revised the calibration procedure for the screen speed control bistables. Inadequacies in the old procedure had resulted in bistables trying to energize two motor speeds simultaneously. Consequently, bistables failed and in turn caused speed controller failures.

The root cause team also noted that the original design change package (DCP) should have identified that the originally-specified motor design was inadequate. Problem Statement 2, items 5.b and 5.c of the Engineering Restart Action Plan, addresses this and other DCP quality issues.

c. Conclusions

The inspectors concluded Salem engineers identified and addressed the causes for poor screen motor and controller performance. The system had not experienced significant challenge due to the extended plant shutdowns, however, the inspectors considered the improvements adequate to support reliable system performance. This NRC restart inspection item is closed.

E8 Miscellaneous Engineering Issues (92903)

On February 23, 1996, the NRC issued their Restart Action Plan for the Salem Units. This Plan contains the programs and corrective actions that the NRC will inspect prior to the restart of the Salem plants. The items described below are included in the NRC restart action plan.

E8.1 Spurious High Steam Flow Signals Causing a Safety Injection - NRC Restart Issue II.38 (OPEN)

a. Inspection Scope

On April 7, 1994, during an automatic Unit 1 reactor trip, the sudden closure of the turbine stop valves caused a pressure wave in the main steam piping. The resulting high steam flow signal, coincident with the low reactor coolant temperature at the time, caused an inadvertent automatic actuation of the safety injection system that complicated the reactor shutdown. This event is described in detail in Inspection Reports Nos. 50-272;311/94-80 and 50-272;311/94-13.

The purpose of the inspection was to review PSE&G's actions to address the inadvertent safety injection signal and prevent its recurrence.

b. Observations and Findings

PSE&G's evaluation of the April 7, 1994 event determined that the high steam flow signal was the result of short duration pressure pulses initiated by the rapid closure of the turbine stop valves. To preclude inadvertent high steam flow signals in the future, the licensee decided to add a lag function to the main steam flow transmitters and, thus, filter out the high frequency pulses that had created the signal. The original modification replaced the existing electronic board of the Rosemount flow transmitters with a "R" type board that had adjustable damping. The licensee selected a damping of 225 $\pm$ 25 milliseconds (msec).

To ensure the adequacy of the damping selected, later PSE&G constructed a mathematical model of the main steam system, from the steam generator to the stop valve. Using this model, they simulated stop valve closures at different power levels and calculated the transient pressure response as a function of time in the main steam piping. These pressure transients were then mathematically filtered through a resistance-capacitance (RC) circuit. Varying the value of the RC-circuit components, the licensee was able to select a time constant such that the amplitude of the pressure wave was less than the amplitude required to initiate a high steam flow signal. This time constant was then used to set the time response of the transmitters.

PSE&G also selected for this analysis a level of protection up to maximum power level of 40%. The licensee stated that this power level was selected because, for a reactor trip from above 40%, a spurious high steam flow signal is always generated. In addition, the coincidence of this signal at high power with a low reactor temperature was considered unlikely.

The inspector's review of calculation S-C-MS-MDC-1377, Revision 0, dated February 2, 1995, determined that the licensee had evaluated wave amplitudes with damping between 500 and 700 msec. and that, at 40% flow, a damping greater than 550 msec. would cause the amplitude of the differential pressure wave at the transmitters to drop below 0.75 psid. The inspectors identified no concerns with the licensee's assumptions and the calculation method.

Based on the results of the calculation, the licensee decided to set the damping of all transmitters to between 550 and 700 msec. The design change packages (DCPs) for Unit 1 (1EC-3328) and Unit 2 (2EC-3293) were revised accordingly. The upper damping limit was selected to ensure the required instrumentation system response.

To evaluate the adequacy of the licensee actions, the inspectors reviewed a variety of documents, including applicable sections of the FSAR and technical specifications, flow diagrams and instrument loops, the DCP safety evaluation and instrument calibration records.

FSAR and Technical Specification Review

In reviewing the emergency core cooling system design bases, the inspectors determined that Section 6.3.3.7 of the FSAR included a time-table for safety action initiation. This table stated that the initiation of a safety injection signal (SI) plus associated instrument lag would occur within 1.2 seconds. Further review of other licensee documents determined that a response time of 2.0 seconds, rather than the 1.2 seconds, was being used as a basis for initiating protective actions. For instance, Table 3.3.5 of the technical specification requires the response time for reactor trip (from SI) due to high steam line flow coincident with low steam line pressure to be $\leq$ 2.0 seconds. The same maximum time was used in the Unit 2 master time response procedure No. S2.IC-TR.ZZ-0002(Q), Revision 0, for the same signal. In addition, for high steam line flow coincident with low-low average reactor coolant temperature (T_{avg} the same documents required the SI signal to be initiated within 5.75 seconds.

The discrepancies were discussed with the licensee who initiated a problem report (No. 00960502113) to review the design bases and initiate necessary corrective actions. The preliminary review by the licensee identified additional discrepancies in this area that are being reviewed under the same problem report. This item is unresolved pending the licensee's evaluation of the identified discrepancies and the NRC's review of the corrective action. **(50-272&311/96-07-05)**

Transmitter Response Time Measurement

As stated previously, to resolve the inadvertent high steam flow signal issue, the licensee decided to replace the electronic board of the main steam flow transmitters with a "R" board which contains a RC circuit to provide for adjustable damping. The response time of the transmitter is adjusted by changing the resistance of this circuit. For any given resistance value, however, the response time of the transmitter is not fixed. Instead, it follows an exponential function that is based on the resistance and capacitance values (time-constant).

In a letter to the licensee, dated July 6, 1994, Rosemount defined the time-constant as the time for the unit to reach 63.2% of a step input pressure. In the same letter, Rosemount also provided some guidance regarding the use of a ramp input to measure the response time of the transmitter and included an example of the difference between the ramp and step function response times. This example showed that for the same time-constant, the response time to a step function is longer than the one measured with a ramp function.

The inspector's review of special test procedure STP-1, Revision 0, a modified version of Maintenance procedure SC.IC-TR.ZZ-0001(Q), Revision 2, determined that, in August 1994, the response time of the Unit 1 steam flow transmitters was changed using the ramp method and that the lag time was measured at the 50% mark of the ramp. The response time curves contained within this procedure also showed that the measured response time would be considerably higher if it were measured at 75-80% of the curve, for instance, and very long as the ramp approached 100%.

Considering that the actual response time of a transmitter is longer than that measured by the ramp input method, as indicated by the example in the Rosemount letter's, and that the transmitter output is an exponential function, the inspectors expressed a concern that the true response time of the transmitter might be longer than desirable. The longer time may not be a concern for the purpose of avoiding an inadvertent SI, following a fast closure of the turbine stop valves. The longer time, however, could be unacceptable for the purpose of initiating a SI within the TS or FSAR specified time, in the event of a main steam line break. The design analysis had not addressed this issue or how the transmitter response time would be affected by different size line breaks.

This issue is unresolved, pending appropriate analysis and action by the licensee and review of its acceptability by the NRC.
(50-272&311/96-07-06)

Safety Evaluation

The inspector's review of the design change package 1ED-3328 determined that the licensee had reviewed the revised design for applicability of the 10 CFR 50.59 and addressed the various questions regarding its impact on the FSAR, TS, and procedure, but concluded that a safety evaluation was not required. Apparently, the same conclusion was reached by the Offsite Safety Review group during the review of the original design change package, in 1994. At that time, the conclusion was based primarily on the basis that the additional time did not impact the initiation of safety injection signal time specified in the FSAR.

Based on the licensee understanding of the issue at the time of transmitter change, the inspectors believed that the results of the evaluation would have remained the same. The inspectors, nonetheless, disagreed with the licensee's conclusions in that the electronic board changes modified the response time of transmitters that are required to perform a function described in the FSAR and the TS. Therefore, a safety evaluation according to 10 CFR 50.59 was required. The inspectors also observed that the current procedure, as well as the procedure in effect at the time of the modification, contained acceptable instructions for the engineering staff to properly address the changes.

The inspectors discussed this issue with the licensee who indicated that, while reviewing the inspector's technical comments, they would also reevaluate the need for a the safety evaluation under 10 CFR 50.59. They also indicated that they would reevaluate their process to determine if it could be strengthened, particularly in light of the new guidance contained in the NRC inspection manual, part 9900. This item is unresolved pending the licensee's reevaluation of this issue and the NRC review of their corrective actions. **(50-272&311/96-07-07)**

Transmitter Calibration

The inspectors reviewed the Unit 2 master time response procedure, No. S2.IC-TR.ZZ-0002(Q), Revision 0, to evaluate the impact of approximately 0.7 seconds delay on the actuation signals that receive their input from the main steam line flow transmitters. The inspectors determined that the licensee calculated the loop response using the arithmetic sum of the worst response time measured for the individual components. This sum was then compared to the required time to establish its acceptability. The inspectors found that the response of the applicable loops was within the required time with sufficient margin.

However, this review also determined that four of the eight flow transmitters had response times ranging from 740 to 870 milliseconds, therefore, well above the 700 milliseconds specified in the calibration procedure. The other four had measured response times of 675 to 700 milliseconds, i.e., within 25 millisecond from the upper limit, using the licensee's ramp method. The additional delay, if measured accurately (see "Transmitter Response Time Measurement," above), would not increase the response time of the loop beyond its required time. The inspectors, nonetheless, expressed a concern that four transmitters had been calibrated outside their required response band and the discrepancies had not been observed or questioned by supervisory personnel in maintenance and plant operations. The licensee initiated an investigation.

This item is unresolved pending completion of the licensee investigation and review of its results by the NRC. **(50-272&311/96-07-08)**

E8.2 <u>(Closed) Violation 50-272; 311/94-18-01</u> **Nonconservative 125 Vdc Battery Acceptance Criteria.**

This issue pertains to the inadequate battery acceptance criteria identified by the NRC during a followup inspection of the electrical distribution system. It is identified as Item II.15 of the NRC restart action plan for Salem.

The NRC conducted a review of the licensee's actions to address this issue and found them acceptable. The details of the NRC review of this item are included in an attachment to Inspection Report No. 50-272; 311/96-06. This item is closed.

E8.3 <u>(Updated) Unresolved Item 50-272; 311/95-06-01</u> **Poor process for Configuration Control of Pipe Supports.**

This item, identified as Item II.19 of the NRC restart action plan for Salem, was opened to track the licensee's efforts in the follow-up and resolution of concerns in regard to errors in stress calculations and to the technical and procedural validity of a modification in the containment spray system.

The inspectors verified that the licensee's investigations had been completed and that the results of the investigation had been submitted to the NRC. The investigation was performed by an outside independent agency and appeared to be broad and thorough. The investigation, however, disclosed some weaknesses in the licensee's process and procedures for handling such issues.

The licensee's letter to the NRC included their proposed, and in some cases implemented corrective actions to resolve these inadequacies. This item remains open pending the NRC review and verification of implementation of these corrective actions.

E8.4 <u>(Updated) Unresolved Item 50-272; 311/94-32-05</u> **Adequacy of the calculation for the new Pressurizer Overpressure Protection System** (POPS) design basis transients. The POPS ability to mitigate overpressure events under 312°F is Item II.20 of the NRC restart action plan.

Background The POPS uses two pressurizer power-operated relief valves (PORVs) to mitigate overpressure transients at low temperature (<312°F) and to keep the peak pressure below the limits of 10 CFR 50, Appendix G, "Fracture Toughness Requirements," for brittle fracture protection. The Appendix G limits are incorporated in technical specifications (TS) as pressure-temperature (P/T) curves specific to each unit's reactor vessel. The original design-basis mass addition transient for the POPS was based on the start of a safety injection pump (780 gpm) and its injection into a water solid reactor coolant system (RCS). POPS was designed to meet the single failure criterion, with either PORV having sufficient relief capacity to limit the peak pressure to less than the P/T curve limit.

An NRC safety evaluation report, dated February 21, 1980, associated with Amendment No. 24 to the Unit 1 TS, approved the Salem POPS setpoint of 375 pounds per square inch gage (psig), based on the calculated peak transient pressure of 446 psig and a 14 psi margin (at that time) below the Unit 1 Appendix G limit of 460 psig. Requirements for the Unit 2 POPS were incorporated into the unit's TS prior to initial startup and were approved based on the Unit 1 POPS safety evaluation.

The P/T limits for all reactor vessels decrease with successive operating cycles due to irradiation effects on the vessel materials. Therefore, margin between the peak transient pressure and the P/T limit change as subsequent revisions of P/T curves are reviewed and approved by the NRC. The Salem Unit 1 P/T curves were revised in February 1990 in TS Amendment No. 108, which established a more restrictive limit of 450 psig at low temperatures. The Unit 2 P/T curves were approved (at the same time) in TS Amendment No. 86, which established a limit of 475 psig. These curves are valid for up to 15 effective full power years of operation.

Subsequent to the TS amendments, in 1993, Westinghouse informed PSE&G of a condition that potentially could cause the automatic start of a second safety injection pump. The starting of a second pump with a solid reactor coolant system would, in turn, result in a pressure spike that could exceed the 10 CFR 50, Appendix G criteria for the POPS relief valves setpoint and put the plant outside the design bases. The NRC review of this issue (Inspection Report 50-272;311/94-32) resulted in the identification of four apparent violations, as described below, and the initiation of escalated enforcement action.

EEI 94-32-01 Failure to report an unanalyzed condition, as required by 10 CFR 50.72 and 73. When PSE&G became aware that the TS margins were no longer available and that the Appendix G limits of both units could be exceeded at low temperature (below 312°F), a reportable condition existed. PSE&G failed to make the required report.

EEI 94-32-01 Failure to request an exemption and obtain NRC pre-approval for using ASME code case N-514, as required by 10 CFR 50.60. To address the POPS issue, initially PSE&G decided to use ASME code case N-514 that adds 10% margin to the Appendix G criteria.

EEI 94-32-03 Failure to initiate corrective actions for a condition adverse to quality, as required by 10 CFR 50, Appendix B, Criterion XVI. When PSE&G recognized that the ASME code case could not be used without prior NRC approval they sought to credit the capacity of residual heat removal relief valve (RH3) to augment the analyzed POPS relief capacity. A subsequent PSE&G analysis confirmed that, with RH3 available, the peak pressure would remain below the Appendix G limit. The crediting of RH3 (without either a safety evaluation or prior NRC approval of the POPS TS change) was, however, under consideration from mid-January to mid-April 1994, when a discrepancy evaluation form (DEF 94-0060) was written. This form documented that relief valve RH3 was not credited in the original POPS analysis or in the existing licensing and design basis for Salem.

EEI 94-32-04 Failure to perform a safety evaluation in accordance with 10 CFR 50.59 to determine whether the change in POPS design-basis transient had created an unreviewed safety question. Since March 1993, PSE&G had initiated several corrective action programs to resolve the POPS issue.

PSE&G Actions

To address the concerns of EEI 01 and 03, PSE&G rewrote their procedures that delineate the operability/reportability and corrective action programs. The inspectors evaluated the process to resolve all identified issues (procedures "Action Request Process" and "Corrective Action Program") and concluded that the new program improved the ability for correcting conditions adverse to quality. Specifically, the new program maintains close control of all aspects of the problem through its correction, with all responsible parties having input to the solution.

The inspectors also determined that PSE&G conducted two surveys to evaluate engineering products and services. The surveys, performed by an independent contractor, pointed out the need for engineering to strengthen its communications, responsiveness, support, and quality of the engineering deliverables for the other departments. PSE&G also performed self assessments and had an outside agency also perform an assessment of the quality of the engineering department. The assessments concurred with the results of the surveys. PSE&G engineering management has conveyed the results of the surveys and self assessments to the engineering staff.

The inspectors verified that the training program had been upgraded to strengthen the identified weaknesses and, through discussions with the engineering staff as well as document reviews, verified that PSE&G engineering were aware of the department weaknesses and were working to resolve them.

Regarding EEI 02 and 04, PSE&G requested the NRC for an exemption to use ASME code Case N-514 in a letter dated December 22, 1994. The NRC granted the exemption by letter dated February 13, 1995. In addition, PSE&G performed 50.59 reviews for the changes in the Units 1&2 design bases. Specifically, they evaluated a new pump configuration for the POPS and, as a result, they were preparing changes to the Final Safety Analysis Report (FSAR) and to the TS bases. A letter delineating the TS basis change was submitted to the NRC on May 31, 1996.

The inspector's review of the revised design basis determined that: the mass addition considered the start of a second safety injection pump; the revised transient is bounded by the 780 gpm flow used in the original design analysis; the calculated peak transient pressure remains 446 psig for the revised mass input, as originally evaluated; and the pressure increase resulting from the operation of two additional reactor coolant pumps is 39 psig for a total of 485 psig. This value is below the new permissible pressure limits of 495 psig for Unit 1 and 544 psig for Unit 2, the new TS pressure limits based on approval to use the code case.

PSE&G's operating procedures were amended to reflect the shutdown configuration of the intermediate and high head pumps as well as instructions for running the safety injection and reactor coolant pumps below 312°F, based on the new design basis.

The inspectors concluded that the NRC approval of the code case and the new pump configurations provided sufficient assurance that the 10 CFR, Appendix G criteria referred to in TS would not be exceeded.

<u>Additional Concern From NRC Inspection Report 50-272,311/94-32</u>

On March 15, 1993, Westinghouse issued a Nuclear Safety Advisory Letter (NSAL-93-005B) informing PSE&G of nonconservatism in their setpoint methodology for POPS. Specifically, Westinghouse determined that the dynamic head, resulting from running reactor coolant pumps (RCPs), and the static head, due to elevation of sensors relative to the reactor vessel midplane, had not been considered in the original setpoint methodology.

The static head error for Salem is relatively small, resulting in a 4.7 psi increase in the peak transient pressure. The dynamic head error, however, is more significant.

For each operating RCP, the difference between the pressure at the reactor vessel midplane and that sensed by the POPS instrumentation increases by approximately 25 psi. Consequently, for a four-loop plant such as Salem, the sensed pressure (with all four RCPs running) could be as much as 100 psi less than the actual pressure at the reactor vessel midplane (the area of concern for P/T curves). These errors are added to the original peak transient pressure since their effect is to offset the pressure at which POPS will actuate. The pressure effects of running two reactor coolant pumps were included in the new design basis with the results identified above. These results and the associated calculations were sent to PSE&G by Westinghouse in a letter dated September 29, 1993.

Conclusions

Acceptable actions were taken by the licensee to address the POPS issue. The adequacy of the new design basis for POPS is currently under review by the NRC's Office of Nuclear Reactor Regulation. Pending NRC assessment of the PSE&G's proposed limiting design-basis transient for POPS, this issue remains unresolved.

E8.5 NRC Restart Issue II.37 - Concerns Over Service Water (SW) Piping Leaks (CLOSED)

a. Inspection Scope

SW piping leaks have been a problem at Salem since its construction. The purpose of this review was to evaluate PSE&G's resolution of the service water pipe erosion.

b. Findings and Observations

The carbon-steel-lined pipe is susceptible to corrosion at locations where the steel is exposed to the river water, such as weld joints. This corrosion is aggravated by the high biological activity in the river water. The resulting micro-biological influenced corrosion (MIC) proved to be aggressive.

To address this issue, since 1986 PSE&G has been gradually replacing the existing piping with a more corrosion resistant piping made from AL6XN, a stainless material with 6% molybdenum. Over the years, PSE&G has been inspecting the new piping at various opportunities with very good success; to date no leaks were identified in the new piping. During the current outage, PSE&G completed the SW piping changes for both units; all of the piping were replaced except for the underground piping and several through-wall penetrations. The underground piping of steel reinforced concrete and the supply headers of the pipe tunnel receive a 100% inspection, by divers, every other refueling outage. No degradation has been observed in this piping to date. The through-wall penetrations received a 100% inspection this outage and only minor weld repairs to some pits and seal welds were required. Both the underground and pipe penetration piping are scheduled to be inspected as indicated above. Rubber expansion joints will be replaced on their existing preventive maintenance frequency, which has been successful to date.

c. Conclusions

Based on his review of related documents, including a compiled graph showing a steady decrease from thirty leaks in 1991 to two leaks in 1995, the inspectors concluded that PSE&G had taken sufficient steps toward resolving the Salem SW system leak issues. This item is closed.

E8.6 NRC Restart Issue II.29 - Reactor Head Vent Stroke Times (CLOSED)

a. Inspection Scope

On July 6, 1994, the Unit 2 safety-related reactor head vent valve 2RC40 failed to operate (stroke open) during testing. Unit 2 was in cold shutdown. PSE&G speculated that the low reactor coolant system temperature may have promoted boric acid crystallization and adversely affect the valve operation. Subsequently, on July 10, 1994, upon increasing the reactor coolant system temperature and confirming the functionality of the valve, PSE&G returned the valve to normal service. They did not, however, perform a formal review or assessment of the failure relative to preventive maintenance, operability, actions to prevent recurrence, or generic implications, in accordance with the applicable "Work Control Process" procedure. In addition, this failure of a safety-related component was never documented. The purpose of this review was to evaluate PSE&G's resolution of the reactor head vent times.

b. Findings and Observations

Following the issuance of a violation, PSE&G investigated the issue and found that the valve (2RC40) and others like it, used in the same application, were worn internally. The wearing of the valve caused the seat to start leaking and the boric acid to be present. PSE&G also determined that the reactor vent was the only place were these valves are used in boric acid system applications. PSE&G took the following steps to correct the situation and prevent recurrence:

- They upgraded the corrective action program as described in paragraph E8-1. In addition the maintenance department established a group, with manager, dedicated to root cause investigation and corrective action determination. This group received level 1 root cause analysis training and was given a lower threshold for analysis implementation.

- They replaced all the reactor head vent valves and instituted a surveillance program for them. This program will involve disassembly and inspection of the valves every 54 months to check for wear, cycling of the valves every time the reactor is placed in cold shutdown, and flushing of the valves with demineralized water after cycling them for surveillance. The latter practice was started when the old valves began to leak.

The inspectors reviewed the statistics compiled by the maintenance department over the last seven months and observed an increase in self-identified problems in the areas of procedure, process, and field discrepancies.

c. Conclusions

Based upon the above review and considering the increased attention to the department weaknesses, the actions taken regarding the physical hardware changes, and the surveillance program established for the valves the inspectors concluded that appropriate actions had been taken to address the reactor head vent issue and that improvements were being made in the maintenance area. This item is closed.

E8.7 **<u>(Updated) Unresolved Item 50-272; 50-311/93-26-01 - Pressure Locking and Thermal Binding of Wedge Type Gate Valves</u> PSE&G's resolution of the pressure locking and thermal binding of wedge type gate valves is Item I.̈.24 of the NRC restart action plan.**

During a November 1993 NRC inspection, the NRC reviewed PSE&G's evaluation of the pressure locking and thermal binding potential for gate valves at the Salem plant. PSE&G had originally conducted a study in 1984 in response to Significant Operating Event Report 84-07. Based on the results of this study, they concluded that all susceptible valves were equipped with either internal or external protection devices that would prevent the occurrence of pressure locking or thermal binding.

Following Generic Letter (GL) 89-10, PSE&G reassessed the susceptibility of the motor operated valves (MOVs) identified in their original study. They concluded that twelve additional valves should have been included in the original study. Of these, four appeared to require additional evaluation to determine their susceptibility and the need for additional actions. This item was left unresolved pending completion of PSE&G's evaluation (NRC Inspection Report Item No. 50-272/93-26-01 and 50-311/93-26-01).

Prior to the NRC's follow up to the above open item GL 95-07 was issued extending the concerns of GL 89-10, Supplement 6 to all gate valves. PSE&G performed an assessment in accordance with GL 95-07 and identified a total of 22 valves for both units requiring corrective actions as follows: Ten valves required the drilling of weep holes, a practice recognized by the GL; the holes were drilled. Four valves required procedural changes to request cycling of the valves after running their respective pumps to prevent pressure binding; this item was in the process of being done. Four valves required recalculation of their thrust values to address the thermal binding concerns; the calculations had been completed. Four valves required the change of the motor controls from torque to position control along with a recalculation of the thrust limits. The calculation were completed, but the new limit switches had not installed.

The inspectors reviewed the licensee's actions to address pressure locking and thermal binding of wedge type gate valves and concluded that acceptable actions had been taken. The inspectors also reviewed the supporting calculations and found them acceptable. This item remains open pending PSE&G revision of the above procedures and installation of the above modifications and the NRC review of the completed tasks.

E8.8 NRC Restart Issue II.28 - Reactor Coolant Pump (RCP) Seal Water Flow Problems (CLOSED)

a. Inspection Scope

On February 19, 1994, the Salem Unit 2 control room operators shut the plant down from 47% power to remove No. 21 RCP from service because of a low seal water leakage flow. This event, in conjunction with other related RCP seal events (Inspection Report Nos. 50-272; 311/94-32 and 95-11) prompted NRC review of these RCP seal failures. The purpose of this review was to evaluate the licensee's root cause determination of the causes and their planned corrective actions to address these seal problems.

b. Findings and Observations

PSE&G engineering hired a consultant with expertise in Westinghouse RCP seals and the pump manufacturer to work with them to perform a root cause analysis of the RCP seal failures. The analysis determined that the primary cause of the failures was corrosion build up across the No. 1 seal. Seven recommendations resulted. These recommendations and the rationale for PSE&G resolution follow.

- Continue the program to reduce mesh size of the seal injection filters. PSE&G considered this a "restart" activity and indicated that they will reduce the size of the filters mesh in the RCP seal injection and the reactor coolant system (RCS). Starting with 2 microns they intend to decrease the mesh size to as low as is possible over the fuel cycle. During the cycle, they also intend to clean up the system to the optimum cleanliness possible. PSE&G polled the industry and determined that, by using this approach, other utilities had attained good results in lowering corrosion buildup throughout the RCS and in particular in the No. 1 seals.

- Review operating procedures to ensure seal injection is maintained during shutdown, outage and startup, and especially during reactor coolant fill operations. This recommendation was intended to keep the reactor coolant from going through the seal during the above modes of operation. The procedures implementation was confirmed via procedure review by the inspectors.

- Review operations of the boron system and boration practices to determine whether the RCP seals are being exposed to unnecessarily harsh and avoidable chemistry transients. The licensee completed this task and found that no operation of the boric acid system fell outside the system design. Engineering, however, issued an action request (AR) No. 960603249) to research this further and to ensure that the addition of boron does not affect the overall system chemistry.

- Examine the particulate downstream of the seals to ensure that sizes are not greater than the seal filters allow. The intent of this recommendation was to ensure that the seal filters were not being bypassed and that there was no source of crud downstream of them. PSE&G Engineering stated that with both units shut down for more than one year there were no reliable sources (old filters) to examine and that all of the old filters had been crated for offsite shipment and burial. Therefore, no action could be presently taken to satisfy this recommendation.

- Test the boric acid system for high levels of corrosion products as a result of high boric acid levels. PSE&G stated that the system already had filtration for particles greater than 2 microns. Therefore, significant particles would not enter the RCS or the charging and letdown system CVCS. Also, PSE&G stated that they operated the RCS within the chemistry guidelines of EPRI and Westinghouse. Therefore, no action was required at this time.

- Review the seal injection system especially downstream of the seal injection filters for components that have the potential for exposing carbon steel or other corrodible materials to the borated reactor coolant. PSE&G considered this recommendation a post-restart item. Therefore, they issued an AR (No. 960603249) to continue an already existing program to look for potential carbon steel or corrodible materials in the RCS.

- Flush the seal injection system at high flow rate. PSE&G stated that this was not practical because the RCS, CVCS and the seal injection systems operate in a closed loop and that all systems would have to be flushed for effective results. Also, the seal injection lines are flushed during the RCS fill, when the seal injection is operated and the seals are bypassed. Therefore, no further action was required.

Further, in their effort to resolve the RCP seal difficulties PSE&G also reviewed 139 records from the Nuclear Plant Reliability and Data System (NPRDS). Using the results of their root cause analysis and the information derived from the other sources, PSE&G developed a program that is comparable with those of other Westinghouse utilities. In addition, PSE&G issued a PR, No. 9590818341, to investigate the possibility of changing two of the No.1 seals every outage, a program that has become a standard practice at several other utilities having relatively few problems with their RCP seals.

c. Conclusions

The inspectors concluded that PSE&G had conducted the required reviews and had developed the most up-to-date information available regarding RCP seals. Even though the licensee had not accepted every recommendation from their consultant, taken as a whole, their actions appear appropriate to correct their program weaknesses. This item is closed.

E8.9 <u>(Closed) Unresolved Item 50-272 & 311/92-01-04</u> **The containment spray motor operated valve operability concern is Item II.1 of the NRC restart action plan.**

During a refueling outage, in January 1992, PSE&G engineering identified a concern regarding the operating capability of the containment spray discharge isolation valves of both Salem units (11,12,21,22CS2). The source of their concern was the difference between the originally specified (200 psid) differential pressure against which the valve motor operators were required to function and the one they had preliminarily calculated (241 psid) in response to Generic Letter 89-10. PSE&G took compensatory measures to continue operating the units, as delineated in NRC combined Inspection Report 50-272; 311; 354/92-01 and informed the NRC that they would replace the motors during the next outage of sufficient length to perform the replacements.

Due to switchyard problems Salem was experiencing, PSE&G replaced some transformers with ones of larger capacity. This change increased the degraded grid voltage available at the plant components. With the higher grid voltages PSE&G reevaluated their MOV program. New calculations for the above MOVs showed that, with appropriate thermal overloads in the motor control circuits, the installed motor could still be used. The new overloads were installed and the motors tested both statically and dynamically with satisfactory results.

The inspectors reviewed the calculations and test results and concluded that sufficient bases existed to ensure the operability of the valves. This item closed.

E8.10 <u>Conclusions and General Comments</u>

The inspectors review of the issues described in Sections E8.1 through E8.9 concluded that PSE&G's action to resolve five outstanding issues were sufficient for their closure. One additional issue, pertaining to pressure locking and thermal binding of safety related valves, remained open pending the licensee's completion of scheduled activities to resolve it. Further, resolution of the pipe support configuration control and of the POPS issues remained open pending the NRC completion of inspection activities.

However, PSE&G's actions to resolve the NRC concern regarding potential safety injection signals caused by spurious high steam flow signals were insufficient for closure of the issue. The NRC review of this issue concluded that the design changes performed in 1994 to dampen the response of the steam flow transmitters and delay the injection signal were narrowly focused in that they did not fully evaluate the impact of the changes. In addition, the justifications to address the inspectors questions and comments were insufficient to close the issue. As a result of this review, the NRC identified four specific concerns that require the licensee's resolution.

The quality of the licensee's packages to resolve the above items was adequate with improvements noted in packages developed later in the inspection period. These improvements were primarily due to the detailed review of closure packages by the system readiness review committee and by the management review board. For instance, the inspectors had reviewed the package for item II.28 (Section 8.8) prior to PSE&G's review process taking place. The inspectors found that the package had not thoroughly addressed all of the recommendations of the root cause analysis. The package was also rejected by PSE&G during their first step of the review process. After the package was reworked and PSE&G completed their review, the inspectors found that all issues had been addressed in sufficient detail to warrant closure of the issue.

E8.11 Review of UFSAR Commitments

A recent discovery of a licensee operating their facility in a manner contrary to the Updated Final Safety Analysis Report (UFSAR) description highlighted the need for a special focused review that compares plant practices, procedures and/or parameters to the UFSAR descriptions. While performing the inspections discussed in this report, the inspectors reviewed the applicable portions of the UFSAR that related to the areas inspected. Except as described in Section 02.1.b and E8.1.b of this report, the inspectors verified that the UFSAR wording was consistent with the observed plant practices, procedures and/or parameters.

IV. Plant Support

R1 Radiological Protection and Chemistry (RP&C) Controls

R1.1 Ammonia Leak in Unit 2 Turbine Building

a. Inspection Scope

The inspectors observed licensee response to an ammonia leak in the turbine building of Unit 2.

b. Observations and Findings

On June 7, 1996, ammonia leaked into the basement of the Unit 2 turbine building. The leak resulted from two separate activities. On June 4, plant staff opened a pipe union to flush and drain a section of the ammonia feed system. The workers relied on normally closed valves to provide isolation from the ammonia storage tank while the union was open. They did not apply safety blocking tags to these valves, and, therefore, did not ensure the open piping remained isolated from the ammonia storage tank. Subsequently, a chemist, not knowing other workers had opened the union, opened the normally closed valves to fill bottles from the ammonia storage tank. As a result, about five gallons of ammonia leaked from the tank through the open union and into the turbine building basement before operators stopped the spill.

The inspectors reviewed the tagging boundary for the drain and flush evolution, and NC.NA-AP.ZZ-0015(Q), Rev. 4, *Safety Tagging Program* (NAP-15). The procedure requires that plant staff establish tagging boundaries to isolate energy sources from personnel. The ammonia leak demonstrated that plant staff did not adequately isolate the ammonia tank from plant staff working in the turbine building. (Section 04.3 has additional details)

c. Conclusions

The inspectors concluded plant staff did not comply with the tagging procedure requirements. The procedure non-compliance did not violate regulatory requirements since the work on the union was not a regulated activity. The inspectors noted, however, that plant staff failed to recognize the need to apply red blocking tags to ensure isolation of the ammonia storage tank from open portions of system piping. As a result, they failed to protect other workers in the plant. Had the work involved higher energy systems or safety-related equipment, or if the storage tank isolation valves remained open longer, the staff's inadequate performance could have resulted in more serious consequences.

S4 Security and Safeguards Staff Knowledge and Performance

S4.1 Security Awareness

a. Inspection Scope (71707)

The inspector conducted frequent tours of the plant and periodically assessed physical security controls.

b. Observations and Findings

On May 27, 1996, the inspector discovered a security guard, seated and inattentive, in a secluded area of the Unit 2 auxiliary building. The inspector discussed the guard's inattentiveness with security supervision.

Security supervision talked to the guard and determined that the guard had been alert and within his assigned area. Security supervisors instructed the guard that although he was alert, he should also appear alert. The inspector independently requested, received, and reviewed recorded information that indicated that the guard remained seated for 21 minutes until disturbed by the inspector. The inspector discussed this observation with security management. Based on the guard's good performance record, Security management counseled the guard. In addition, Security management reinforced its standards and expectations concerning attention to duty to the security force organization.

c. Conclusions

A security guard did not patrol his assigned area continuously. Security supervision follow up did not thoroughly assess the guard's inattention to duty. They limited the thoroughness of their followup action because of previous good performance of the guard. During the exit meeting, the general manager noted this as a poor practice and provided the proper guidance and direction to the security organization.

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 July 3, 1996. 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.

X3 Management Meeting Summary

From June 25 through June 28, Mr. H. Miller, NRC Regional Administrator, Region III, visited Salem and Hope Creek to tour the plants and meet with various PSE&G managers and supervisors.

X4 Management Changes

Public Service Electric and Gas announced the following management changes: Charlie Munzenmaier assumed the position of General Manager, Steam Generator Replacements, effective June 3. Dave Garchow assumed the Salem General Manager position effective June 14. Mark Reddemann assumed the position of Director, Steam Generator Projects, effective June 14. Marty Trum assumed the position of Director, Nuclear Operations Services, effective June 17.

INSPECTION PROCEDURES USED

IP 61726: Surveillance Observations
IP 62703: Maintenance Observations
IP 71707: Plant Operations
IP 92903: Follow up - Engineering

ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

50-272&311/96-07-01	URI	UFSAR and licensing basis nonconformances
50-272&311/96-07-02	VIO	procedure noncompliance
50-272&311/96-07-03	IFI	switchgear testing
50-272&311/96-07-04	VIO	reporting guidelines

LIST OF ACRONYMS USED

CAP	Corrective Action Program
CR	Condition Report
CRI	Control Room Indicator
DCP	Design Change Package
DFOST	Diesel Fuel Oil Storage Tank
EDG	Emergency Diesel Generator
EMIS	Equipment Malfunction Information System
FHB	Fuel Handling Building
I&C	Instrumentation and Controls
IST	In-service Testing
LER	Licensee Event Report
N/A	Not Applicable
NAP	Nuclear Administrative Procedures
NRC	Nuclear Regulatory Commission
OE	Operating Experience
OEF	Operating Experience Feedback
PDR	Public Document Room
PMT	Post-Maintenance Testing
PSE&G	Public Service Electric and Gas
QA	Quality Assurance
RP	Radiation Protection
RP&C	Radiological Protection and Chemistry
RVLIS	Reactor Vessel Indication System
SAC	Station Air Compressor
SFP	Spent Fuel Pool
SNSS	Senior Nuclear Shift Supervisor
SPT	Station Power Transformer
SRO	Senior Reactor Operator
TS	Technical Specification
UFSAR	Updated Final Safety Analysis Report
URI	Unresolved Item
UT	Ultrasonic
VIO	Violation
WO	Work Order