U. S. NUCLEAR REGULATORY COMMISSION

REGION I

Docket Nos:	50-272, 50-311
License Nos:	DPR-70, DPR-75
Report No.	50-272/96-08, 50-311/96-08
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:	June 30, 1996 - August 10, 1996
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EXECUTIVE SUMMARY

Salem Nuclear Generating Station
NRC Inspection Report 50-272/96-08, 50-311/96-08

This integrated inspection included aspects of licensee operations, engineering, maintenance, and plant support. The report covers a 6-week period of resident inspection.

Operations

Operators continued to demonstrate increased ownership for the plant. For example, the Senior Nuclear Shift Supervisors (SNSS) continued to provide focus on safety at the General Manager's morning meeting. In addition, senior operations staff identified less than adequate material conditions and pursued resolution of the conditions. Control room operators demonstrated significantly improved plant knowledge. In one case, however, the control room operators did not understand the design function of a service water common header pressure control valve. The operations staff readily accepted observations concerning areas for improvement, and took a leading role in holding the entire Salem staff to high standards. Senior Salem managers also demonstrated the ability to perform and act on candid self-assessment. For example, they concluded that the maintenance staff continued to produce poor quality results. As a result, the managers extended the Salem Unit 2 outage schedule to the end of 1996, shifted the focus of outage activities to restoring equipment (rather than meeting deadlines), and initiated a major effort to obtain significant improvement in the performance of all Salem maintenance personnel. In addition, the Salem General Manager reduced the number of weekly meetings to allow increased manager time for field observations, reorganized the work control and maintenance organizations to provide improved leadership, and increased the focus on safety and quality during morning meetings. Through their actions, the Salem managers demonstrated determination to address and resolve work control and maintenance related equipment and staff performance deficiencies. (Sections O1.1 and O4.1)

The Operations staff continued, however, to evidence weak performance in some areas. For example, operators failed to update the Salem Tagging Request Inquiry System, a database used to control and monitor valve and breaker positions. As a result, inspectors and plant staff found service water valves out of their expected positions. In one case, the mis-positioned valves could have resulted in damage to a safety-related pump. Significantly improved vigilance by an operator, technician, and system engineer prevented damage to the pump. Operators did not demonstrate consistently appropriate response to the potential that mis-positioned valves resulted from tampering. In one case, operators did not act on the possibility of tampering until the inspectors questioned their actions. In a second case, the Nuclear Shift Supervisor and the Senior Nuclear Shift Supervisor SNSS immediately recognized the potential for tampering and took prompt and appropriate action. (Section O1.2)

Salem significantly improved the operability determination process through recent revisions. Inspectors found minor weaknesses, and determined that operations and system engineering had not completed training on their respective processes (Section O2.1). On two occasions, operators did not consider the possibility that identified equipment failures could apply to similar plant equipment. In one of these cases, operators did not question the generic applicability for a failure of a safety-related auxiliary oil pump supplying a charging pump. As a result, they did not prevent a second failure when subsequently another charging pump (Section O2.2).

Inspectors continued to identify weaknesses in operating procedures. The procedures did not contain information needed to protect plant equipment and personnel. Procedure weaknesses allowed a service water pressure perturbation, and could have permitted residual heat removal pump vortexing, potential injury to maintenance personnel, and a potential reactor vessel overpressurization. Operations management initiated actions to strengthen these procedures (Section O3.1).

The Emergency Operating Procedure (EOP) Group recognized the problems that existed in the former set of EOPs, implemented an effective process to resolve those problems, and produced a set of significantly improved EOPs and bases. PSE&G had not completed operator training on the new EOPs or implemented EOP maintenance tools in order to maintain the EOPs at this high level of quality (Section O3.2). The Salem training staff significantly improved the training programs through implementation of the Salem Training Restart Action Plan. The PSE&G staff made significant improvements in training program self-assessments and line management involvement in the training programs (Section O5.1).

The Management Review Committee (MRC) did not consistently insure closure packages for identified technical and programmatic concerns demonstrated that plant staff had completed essential corrective actions. (Section O7.2). For example, plant staff had not completed the corrective actions for the Salem Unit 2 trip of June 7, 1995, and the MRC did not identify the lack of evidence of corrective action (Section O7.1).

Maintenance

Ineffective maintenance frequently resulted in rework. As a result, Nuclear Business Unit and Salem senior management planned to test the maintenance staff to determine the areas of training weakness and conduct retraining. The intervention, schedule to occur offsite beginning in September, will require that qualified contractors perform maintenance during the PSE&G maintenance staff requalification process (Section M1.2).

In addition to ineffective maintenance, inspectors and plant staff found other problems with the performance of maintenance. For example, although PSE&G has improved the Foreign Material Exclusion (FME) program, significant problems continue to exist with implementation of the program. (Section M2.1) Inspectors identified one technician failure to perform a required post-maintenance test (PMT) on safety-related valves, and a second example revealed itself. (Section M4.1) In addition, the Operations staff identified

numerous deficiencies with the planning, scheduling and performance of PMTs. The senior Nuclear Business Unit managers and the inspectors independently identified that plant staff and contractors have not kept Salem clean. The inspectors identified that workers did not comply with requirements for storage of safety-related materials. The managers promptly took measures to clean the plant, dispose of the poorly controlled materials, and emphasize their expectations for housekeeping and material controls (Section M7.1).

Engineering

An independent assessment conducted by the Salem Integrated Readiness Assessment team concluded that, in general, Engineering appeared on the right track to support restart in a safe manner. Inspectors noted that, in one case, the Engineering staff appeared reluctant to document performance problems using the Corrective Action Program. Although the team identified four examples of inadequate engineering performance, the engineering staff did not initiate a Condition Resolution, as required, until questioned by an inspector. (Section E7.1). Engineering staff did not demonstrate strong ownership for plant systems in some cases. Although they provided a detailed list of recommendations for laying up various systems and components they did not actively identify and resolve deviations from their recommendations (Section E8.4).

Engineering took adequate corrective action to address a number of NRC restart inspection items, including the 21RH10 valve (Section E2.1), and the information provided in the PSE&G response regarding potential for Control Rod Drive Mechanism penetration cracking (Section E8.1). In some cases, such as safety injection pumps and closure of the main steam isolation valves, effectiveness of the corrective actions remains open until plant staff can test the corrective measures (Sections E2.2 and E2.3).

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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. Operators continued to demonstrate increased ownership for the plant. For example, the Senior Nuclear Shift Supervisors (SNSS) continued to provide focus on safety at the General Manager's morning meeting. In addition, senior operations staff identified less than adequate material conditions and pursued resolution of the conditions. Control room operators demonstrated significantly improved plant knowledge. The operations staff generally seemed to accept observations concerning areas for improvement more readily, and took a leading role in holding the entire Salem staff to high standards. Senior Salem managers also demonstrated the ability to perform and act on candid self-assessment. For example, they concluded that the maintenance staff continued to produce poor quality results. As a result, the managers extended the Salem Unit 2 outage schedule to the end of 1996, shifted the focus of outage activities to restoring equipment (rather than meeting deadlines), and initiated a major effort to obtain significant improvement in the performance of all Salem maintenance personnel. In addition, the Salem General Manager reduced the number of weekly meetings to allow increased manager time for field observations, reorganized the work control and maintenance organizations to provide improved leadership, and increased the focus on safety and quality during morning meetings. Through their actions, the Salem managers demonstrated determination to address and resolve equipment and staff performance deficiencies.

O1.2 Operator Control of Safety-related Equipment

a. Inspection Scope (71707)

The inspectors toured accessible plant areas to assess plant and equipment conditions. Inspectors discussed plant configuration control with Operations management, operating shifts, and Security personnel.

b. Observations and Findings

On July 18, 1996, the inspector discovered 21SW161, a normally closed and locked valve, open and unlocked. The 21SW161 valve provides an emergency service water (SW) supply to the auxiliary feedwater (AFW) system. The Tagging Request Inquiry System (TRIS) listed the 21SW161 as closed and locked. The

operating shift promptly closed and locked the valve, however, they did not immediately react to the possibility of tampering until the inspector contacted the Operations Manager. The operating shift subsequently determined that an operator, on an approved work order, repositioned the valve on July 15. The operator failed to update TRIS in accordance with management expectations. Poor communication between Operations and Maintenance contributed to operators maintaining the 21SW161 in the abnormal position after maintenance technicians completed work on July 15. There was no safety consequence to this lack of configuration control due to plant condition (no other applicable SW or AFW work).

On July 19, an equipment operator discovered a normally chained and locked 18-foot step ladder removed from its designated position. Operators needed the ladder to align temporary air compressors to provide a backup air supply. The operating shift did not respond to evaluate potential tampering until the inspector contacted the Operations Manager. The Operations Manager initiated a condition report and night order book entry identifying Operations' insensitivity to potential malicious tampering. The Operations staff drafted a "Response to Potential Tampering" procedure to provide guidance in this area.

In addition, while running no. 22 safety injection pump maintenance retest on August 8, workers found 2SW162 and 2SW181 closed. Operators expected to find the valves, used to isolate service water to the lube oil cooler, in their normally locked open position. The equipment operator began to reopen the valves, however, when the shift supervisor learned of the mis-positioned valves he terminated the pump test, directed operators to quarantine the area, and requested security to help determine the cause of the mis-positioned valves. The Senior Nuclear Shift Supervisor (SNSS) also notified plant managers, the Hope Creek SNSS, and the inspectors. Later that day, Operations staff determined that on July 31, an operator releasing a safety tags had opened the valves, as directed by the release order. He identified a service water leak and appropriately shut the valves. The inspector verified that the operator also marked the release documents, as required, to indicate that he left the valves in an abnormal condition due to the service water leak. The inspector verified that the independent verification also documented that the operator left the valves in an abnormal condition (closed). The operations staff concluded that plant staff had not accurately updated the TRIS to reflect the actual valve positions after the manipulations on July 31. Procedure SC.OP-DD.ZZ-OD08(Q), *TRIS Tagging Operations*, Rev. 6, step 2.1.7.C. requires that operators sign and date that TRIS has been updated on the Tagging Request Worksheet. Failure to update TRIS is a violation (**VIO 50-272&311/96-08-01**).

The inspectors observed that vigilance by plant staff during the pump run prevented damage to the safety injection (SI) pump. Failure to update TRIS, however, resulted in unnecessarily risking damage to the pump.

The inspectors noted that the Salem unit 2 nuclear shift supervisor and the SNSS promptly identified that mis-positioned valves represented a potential indication of tampering. They took prompt, aggressive, action to determine the cause, while simultaneously verifying that other systems did not have indications of tampering.

They also appropriately notified Hope Creek. The Hope Creek staff, however, did not demonstrate appropriate sensitivity to the potential for tampering, and took no action other than to mention the Salem problem to Hope Creek staff during morning meetings.

c. Conclusions

Operations staff failed to update the Salem TRIS. As a result, an inspector found one service water valve out of its expected position and operators found two additional valves out of position during a safety injection pump test. In the latter case, the mis-positioned valves risked damage to the no. 22 safety injection pump. In the first instance, operators did not respond to the potential for tampering until questioned by the inspectors. In the last instance, the Salem Unit 2 Nuclear Shift Supervisor and the Senior Nuclear Shift Supervisor placed the pump in a safe condition and took immediate action in response to the potential for tampering.

02 Operational Status of Facilities and Equipment

O2.1 Review of Operability Determinations, NRC Restart Item III.6 (Open)

a. Inspection Scope (71707)

The inspectors performed a review of PSE&G's methodology for assessing the operability of degraded or nonconforming structures, systems and components and how these issues were tracked through resolution. This effort included an evaluation of current programmatic guidance and a sampling of "active" operability determinations (OD), as well as an assessment of a recently completed safety review group audit of the OD process.

b. Observations and Findings

Based on a review of NRC inspection reports issued for Salem in the last two years, the inspectors noted several prevalent themes regarding the performance of OD's. Specifically, there has been:

- a lack of clear guidance for performing operability evaluations
- weak documentation of the technical bases of operability
- a weak review and approval process
- inadequate training for operators and supervisors
- weak engineering department support

The inspectors noted that PSE&G management has acknowledged each of these deficiencies, and has taken several steps to address and resolve them.

Of primary significance was the development of clear procedural guidance that systematically guides the implementation of the OD process. The inspectors reviewed the applicable procedures (SC.OP-AP.ZZ-0006 (Q) revision 2, "Operability Determination" and SC.SE.AP.ZZ-0001(Q) revision 0, "Follow-up Operability

Assessment") in detail and judged that they adequately addressed the above noted prior performance concerns. Specifically, these documents strictly define what an OD is, how one is made, where it is documented, and what compensatory measures are necessary. Further, the procedures mandate added levels of concurrence, including a Station Operations Review Committee (SORC) review within 24 hours of making an OD. Finally, clear standards are provided for when an OD can be considered resolved.

Despite these programmatic improvements, the inspectors determined that the new guidance did not require an evaluation of the generic applicability of identified degraded or nonconforming conditions to similar plant or opposite unit components, a feature that had appeared in earlier versions of the OD procedure. The inspectors also noted that, though the new OD process requires a monthly audit to ensure (in part) that the aggregate effect of open OD's has not caused a system to become inoperable, no documentation of previous audits was available for review and no standard for aggregate impact assessment is provided.

In addition, the inspectors learned that the operations department was employing an informal software database tracking system for managing "inactive" OD's (i.e. degraded or nonconforming equipment not required in the current plant operating mode), a process which was not governed by either of the controlled OD procedures. This process was developed to reduce the number of OD's shift personnel were forced to manage, as well as to code each of them with their technical specification operational mode applicability to ensure that they would be "re-activated" prior to plant entry into a mode in which the associated equipment was required. While the stated basis appeared to be sound, the inspectors judged that the operations department's use of an uncontrolled OD management process increased the potential for error in monitoring the existing backlog and tracking individual items to closure.

The inspectors reviewed a sample of six of the seventeen "active" OD's listed in the operating shift's log book. Of those reviewed, the documented technical bases appeared to adequately support a conclusion of "operable but degraded." Further, the inspectors verified that OD-required compensatory measures were being properly implemented. However, of these six OD's, two qualified for immediate closure under the SC.OP-AP.ZZ-0006 procedure (95-080, 95-140), and three qualified for transfer to "inactive" status under the informal program described above (95-043, 95-128, 95-140). Additionally, one OD (96-001) included inconsistent guidance for required compensatory actions and another (95-080) had incomplete documentation to support the OD. Finally, PSE&G's most recent OD performance indicator listed nineteen outstanding issues, two greater than tracked in the operations department active log. Collectively these discrepancies indicated a lack of rigor in implementing programmatic controls.

On May 23, 1996, the Salem safety review group (SRG) completed an assessment of the OD process. In their report, the SRG concluded that while OD programmatic controls were capable of supporting station restart, further management attention was necessary to ensure that implementation of program requirements would be

effective. The inspectors generally concurred with the SRG report findings, especially with regard to a noted weakness in OD and follow-up review training for plant operators and system engineers. The inspectors learned that most operators have received training on the newly revised OD process, but have not had recent "performance-based" training on how to evaluate degraded conditions in order to establish system operability. Additionally, no training had yet been conducted for system engineering personnel regarding the expectations of the newly issued SC.SE-AP.ZZ-0001 procedure for OD follow-up assessments.

c. Conclusions

PSE&G's recently revised operability determination process provides clear guidance for documenting and tracking the operability of degraded or nonconforming systems, structures and components, and adds additional levels of station review to ensure that associated technical bases and compensatory measures adequately support a conclusion of "operable but degraded." However, management of "inactive" operability determinations, while technically adequate, lacked formal procedural controls and increased the potential for tracking errors. The documentation associated with several "active" operability determinations did not consistently implement established guidance. Additionally, plant operators and system engineers had not received recent training on how to appropriately evaluate degraded and non-conforming conditions.

02.2 Equipment Status Awareness

a. Inspection Scope (71707), NRC Restart Item III.7 (Open)

The inspector performed control room walkdowns and operator log reviews to assess availability and operability of plant equipment.

b. Observations and Findings

On August 1, 1996, Unit 2 operators noted that the auxiliary oil pump for no. 21 centrifugal charging (CVC) pump did not start in auto as required (CR 960801362). Operators placed the auxiliary oil pump in manual run. On August 2, Unit 2 operators noted that the auxiliary oil pump for no. 22 CVC pump did not start in auto as required (96082073). The operating shift did not consider the potential for common mode failure until the inspector noted the auxiliary oil pump failures. Operation of the no. 22 CVC auxiliary oil pump in auto without an understanding of the failure of no. 21 CVC auxiliary oil pump represented a lack of questioning attitude on part of the operating shift. The system manager stated that operation without the auxiliary oil pump increased bearing wear, but did not threaten pump operability.

In the early morning hours of August 2, 21SW21, a diesel generator service water header supply valve, failed to stroke from the control room during a planned post maintenance test (PMT). (See section 4.1) At 5:47 a.m., Unit 2 operators discovered that 2SJ68, safety injection minimum flow valve, could not be opened

from the control console. (See section 4.1) The operating shift did not consider the potential for common cause failure of the motor operated valves until the inspector noted the degraded condition during a morning control room walkdown. Both valves have common 230 VAC, 28 VDC, and 125 VDC power supplies. Failure to question potential common mode failures of safety-related valves represents a lack of questioning attitude on part of the operating shift. Instrumentation and Controls (I&C) technicians determined that the valves failed for different mechanical reasons. The inspector determined that maintenance's failure to perform timely PMTs applied to both valves. (See section 4.1)

c. Conclusions

The operating shift failed to evaluate charging pump auxiliary oil pump and safety-related motor operated valve failures for potential common mode failures.

03 Operations Procedures and Documentation

03.1 Procedure Quality, NRC Restart Item III.3 (Open)

a. Inspection Scope (71707)

The inspector observed plant activities and reviewed the controlling procedures to assess procedure adequacy.

b. Observations and Findings

Control room operators maintained Unit 2 defueled and at the midloop position using S2.OP-SO-CVC-0007, revision 4, *Fill and Vent of CVCS*. The CVC-0007 procedure did not provide water level limitations to preclude residual heat removal (RHR) pump vortexing. In addition, S2.OP-SO.RHR-0001, revision 4, *Initiating RHR*, did not provide similar limitations. Despite the procedure weakness, all operators interviewed knew and understood RHR pump operating restrictions. The Unit's defueled status made this a RHR pump reliability concern and not an immediate safety concern. Operations management initiated a procedure revision for the CVC-0007 and RHR-0001 procedures (R15102).

Unit 2 operators used S2.OP-SO.CC-0002, revision 7, *21 and 22 Component Cooling Heat Exchanger Operation*, to remove no. 21 component cooling heat exchanger (CCHX) from service. The CC-0002 procedure did not provide specific guidance to control this evolution resulting in a SW pressure perturbation. (See section 04.1) Step 5.2.3 instructed the equipment operator to slowly close the CCHX SW inlet (SW122) and SW regulating (SW127) valves. The procedure provided no guidance on coordinating the above SW flow reduction with use of the pressure control valves (SW308/SW311) and the SW bypass valves (SW50s) to preclude excessive SW pressure swings. Operations management initiated actions to improve operator CC system training and to revise the CC-0002 procedure.

Unit 2 operators used S2.OP-SO.CA-0001, revision 2, *Control Air System Operation*, to control realignment of SW spool pieces needed to support an emergency control air compressor (ECAC) chill water outage. The CA-0001 procedure did not provide controls to protect maintenance personnel. In particular, the procedure tagging ensured use of an ECAC breaker danger tag to protect the ECAC, however, it did not require SW valve danger tags to protect personnel from pressurized SW piping. Mis-operation of the closed SW valves could also result in a SW pressure transient. Operations management initiated a procedure revision for CA-0001 (R15078) and initiated a search for additional operation procedures with similar safety tagging controls. On August 10, the operating shift made an on-the-spot change to S1.OP-SO.CA-0001 to require use of SW safety tags during the alignment of no. 1 ECAC SW spool pieces.

Maintenance personnel used SC.MD.FR.FH-0006, revision 9, *Reactor Vessel Head Reassembly*, to reset the head under various plant conditions. The FH-0006 procedure did not provide precautions to ensure brittle fracture prevention for the reactor vessel. Technical Specification (TS) 3.5.3 requires that a maximum of one safety injection pump or one centrifugal charging pump shall be operable whenever the temperature of one or more of the reactor coolant system cold legs is less than or equal to 312 degrees F and the head is on the reactor vessel. As a scheduled reactor head lift approached, Unit 2 operators maintained one charging pump in service and two safety injection pumps available. Although TS 3.5.3 did not apply to Salem's undefined mode, the potential for reactor vessel over pressurization is a vessel integrity concern. In addition, operators could use the FH-0006 procedure under similar circumstances with fuel in the vessel. Vessel overpressurization with fuel in the vessel presents a nuclear safety concern. Operations management initiated actions to provide an additional barrier to vessel overpressurization.

In addition to the NRC identified examples, the operations staff identified numerous improvements to procedures. Operations staff consistently implemented the "On-The-Spot Change" (OTSC) process when applicable. The shift's intolerance for poor quality procedures improved significantly and resulted in many procedure revisions. Operator awareness to problems with guidance "within" procedures increased, however, identification of needed guidance "left out" of procedures, as noted above, remained a weakness. The absence of adequate guidance in the above procedures is a violation **(VIO 50-272 & 311/96-08-05)**. NRC Restart Item III.3, Procedure Quality, remains open pending implementation of corrective actions to ensure adequate guidance is contained in the operating procedures.

c. Conclusions

Several Salem procedures did not contain essential information needed to protect plant equipment and personnel. Procedure weaknesses permitted potential RHR pump vortexing, a SW pressure perturbation, potential injury to maintenance personnel, and a potential reactor vessel overpressurization. Operations management initiated actions to strengthen these procedures.

O3.2 Adequacy of Emergency Operating Procedures, NRC Restart Item III.15 (Closed)

a. Inspection Scope (92903)

Emergency operating procedures (EOPs) provide operating instructions for plant conditions requiring a reactor trip and/or safety injection actuation. EOPs incorporate stabilization and recovery strategies for various postulated events, both within and outside the plant design basis, and include critical safety function recovery strategies designed to protect the physical barriers that prevent fission product release.

PSE&G had various Salem EOP improvement efforts underway since 1994. New company management reorganized these efforts into a comprehensive EOP Group in January 1996, and that group completed the revision of all Salem EOPs, along with the respective EOP bases, by June 1996. The inspector reviewed the EOP Group process used to revise the Salem EOPs, several of the completed EOPs, the performance of EOPs in the Salem simulator, and PSE&G management oversight of the EOP program. In addition, the inspector compared the EOP program to the requirements of the Salem UFSAR.

b. Observations and Findings

The EOP Group process for improving the Salem EOPs included a detailed comparison of each EOP against its associated Emergency Response Guideline (ERG). This comparison also involved a review of the ERG bases to validate the assumptions of the ERG to ensure applicability to the Salem facility. The EOP Group performed this review for all 41 Salem EOPs. The depth of the PSE&G effort was indicated by their submittal of approximately two dozen direct work requests to the vendor, Westinghouse, which proposed revisions and corrections of the generic ERGs and their bases. In addition to the technical review of the EOPs, the EOP program included the streamlining of individual EOP steps and the flowchart for each EOP. Where EOP steps are common between EOPs, the program standardized the format and language of the step to provide consistency between the EOPs. The EOP Group coordinated with PSE&G Engineering to identify all setpoints and numerical values used in the EOPs. All values were calculated by Westinghouse using data provided by PSE&G, appropriately placed in the EOPS, and then consolidated into an "EOP Setpoint Document." In addition to the EOPs themselves, the EOP Group redesigned and reformatted the Salem EOP bases documents to ensure consistent treatment of the Salem-specific procedures when compared to the generic documents.

The inspector performed an in-depth review of five of the new Salem EOPs:

EOP-TRIP-1, "Reactor Trip or Safety Injection",
EOP-SGTR-1, "Steam Generator Tube Rupture",
EOP-LOCA-1, "Loss of Reactor Coolant",
EOP-LOPA-1, "Loss of All AC Power", and
EOP-FRHS-1, "Response to Loss of Secondary Heat Sink".

The inspector compared the new Salem procedures to the corresponding Westinghouse ERG and the previous PSE&G revision, and analyzed the effectiveness of the procedure to properly mitigate the intended abnormal or accident condition. As an additional means to determine procedure adequacy, the inspector observed several simulator scenarios conducted with both initial operator training candidates and previously licensed operators in requalification training. During the observation of the use of the EOPS, the inspector identified a problem in EOP-LOCA-1 in which the procedure had a continuous action step which instructed the operator to not stop any ECCS pumps, yet within the next few steps the procedure had the operator stop a residual heat removal pump. The licensee acknowledged the inconsistency, revised the Salem EOP to remove the first instruction as a continuous action step, and submitted an additional direct work request to Westinghouse to identify the inconsistency as a potential generic concern. Other than this one inconsistency in EOP-LOCA-1, the inspector determined that the Salem staff noticeably improved the EOPs' consistency, accuracy and usability, and that the procedures provided the necessary steps and strategies for operators to respond to plant transients and accidents.

In order to assess management oversight of the EOP program, the inspector attended the SORC meeting for the approval of the "EOP Setpoint Document" and the Management Review Committee (MRC) meeting for the closeout of the EOP NRC Restart Item. The SORC acknowledged the setpoint document effort as a good initiative and had a number of questions regarding the effect of any new setpoints on Salem Technical Specifications and other Salem procedures. The SORC concluded that the 10CFR50.59 review associated with the EOP Setpoint Document had not adequately addressed the safety impact of the setpoint analyses and sent the review back for revision before it would accept the new setpoint document. The MRC asked the EOP Group head several questions concerning the process used to develop the new EOPs, how the new EOPs were to be maintained accurate and consistent, and the schedule for training licensed operators on the new EOPs. The EOP Group leader explained that all operators would receive training on the new EOPs prior to standing watch following plant startup and that the EOP usage guidance and maintenance documents would be completed and approved before plant startup. With these assurances given, the MRC accepted the EOP restart issue as closed. The inspector concluded that both the SORC and the MRC showed a good questioning attitude and maintained the proper oversight role and safety perspective while deliberating the EOP restart issue.

The Salem UFSAR has minimal requirements relating to EOPs. UFSAR Paragraph 13.5.3 requires the Salem plant manual to "include those emergency instructions, with the exception of fire and medical emergency response procedures, necessary to ensure that proper action is taken to handle any malfunction that may occur at either of the Salem units." The inspector verified that the revised set of Salem EOPs met this requirement. In addition, the inspector reviewed the 10CFR50.59 applicability review for EOP-FRHS-1, specifically the review and explanation of why the procedure revision did not change a procedure as described in the UFSAR. The inspector reviewed the description of the procedure steps used to attempt restoration of feed flow to the steam generators. The inspector concluded that the

systems and setpoints described in EOP-FHRS-1 complied with the assumptions and limits described in the Salem UFSAR.

c. Conclusions

Overall, the inspector concluded that the Salem EOPs were now more than adequate; the EOP Group had recognized the problems which had existed in the former set of EOPs, implemented a good process to resolve those problems, and produced a very good set of EOPs and bases as a final product. The inspector noted that PSE&G had not completed operator training on the new EOPs or implemented the EOP maintenance tools in order to maintain the EOPs at this high level of quality. The inspector concluded that the new Salem EOPs fully support Salem restart; this item is closed.

04 Operator Knowledge and Performance

04.1 Awareness of Plant Conditions, NRC Restart Item III.7 (Open)

a. Inspection Scope (71707)

The inspector discussed plant configuration and plant activities with control room operators to assess operator awareness and knowledge.

b. Observations and Findings

For a short period, one SW bay supplied both nuclear headers and the cross connected header supplied the sole source of emergency diesel generator (EDG) SW cooling. The Unit 2 control room operator fully understood the potential to lose all EDG SW cooling and properly evaluated leak isolation response to preclude such a loss.

With Unit 2 defueled, operators filled the reactor coolant system (RCS) to the midloop position. The control room operator maintained a good awareness of RCS level and the status and accuracy of available level indications. Improper RCS level could result in reactor coolant pump (RCP) seal fouling or RHR pump cavitation. In addition, control room operators demonstrated a good knowledge and practical application of RCS level requirements necessary to preclude RHR pump vortexing.

A Unit 2 control room operator did not know the function nor the setpoint of a SW bay common header pressure control valve. This contributed to a drop in SW pressure to 70 psig (105-125 psig normal operating range) when operators removed a component cooling heat exchanger from service. The operator responded promptly to restore SW pressure. Through informal interviews, the inspector determined that most operators knew the setpoint, but did not fully understand the function of the pressure control valve. The inspector discussed this training weakness with the Operation's staff. Operation's staff initiated actions to include the pressure control feature in operator requalification training and discussed the knowledge deficiency in a night order book entry.

c. Conclusion

Operator knowledge concerning plant configuration and operation was generally good, however, the inspector identified a training deficiency involving the function of a service water common header pressure control valve.

05 Operator Training and Qualification

O5.1 Adequacy of Training, NRC Restart Item III.16 (Closed)

a. Inspection Scope (92903)

In March 1995, reviewers identified numerous weaknesses in the Salem Operations Training program affecting every aspect of training. They subsequently conducted two root cause evaluations, one performed by PSE&G personnel, and the other by an independent team of industry peers, consultants and PSE&G personnel. The findings, causal factors and recommendations of the two teams formed the basis for the PSE&G Accredited Training Restart Action Plan.

The inspector reviewed the actions taken by PSE&G in accordance with the Training Restart Action Plan to assess its adequacy and completeness. The inspector also assessed the actions taken by PSE&G in response to Problem Statement 4 of the Engineering Restart Action Plan. Problem Statement 4 documented inadequate training of engineering staff to assure high quality of work and lack of clearly established or maintained staff qualifications.

In addition to the review of the Training Restart Plan itself, the inspector also assessed PSE&G management oversight of the restart issue and their performance in accepting the plan for closure. As part of an ongoing NRC initiative, the inspector compared the training programs with the description of and requirements for the programs contained in the Salem UFSAR.

b. Observations and Findings

The Salem Training Restart Action Plan identified nine problem statements which each had several associated corrective actions intended to resolve the deficiencies in that area. The topics covered by the nine problem statements were:

1. PSE&G management had not established expectations for line and training ownership of training programs;
2. Line and training management had not identified all root causes for training program deficiencies;
3. Open positions in the training staff had adversely impacted the quality of training;
4. Quality of training materials had adversely impacted classroom instruction;
5. Instructor performance weaknesses, including poor student evaluations, reduced the effectiveness of training;

6. Personnel had been performing tasks before their qualification for those tasks had been completed;
7. Training program self-evaluations had not provided critical assessment of the training programs;
8. Internal training oversight and industry peer evaluations had not been properly utilized to identify training weaknesses; and
9. PSE&G had to concur with readiness for accreditation renewal.

The inspector reviewed the PSE&G evaluations which had led to the development of the problem statements and the proposed corrective actions for them. The inspector performed this assessment for all problem statement areas except for the ninth problem statement, which was beyond the regulatory scope of the inspection. Using a sampling method, the inspector selected at least three corrective actions from each of the first eight problem statements and assessed those actions for adequacy and completeness.

The inspector found that PSE&G Training Restart Action Plan had done a thorough job in evaluating the deficiencies of the training program and had provided effective corrective actions as well. PSE&G performed a number of self-evaluations and had made a number of management changes in the Nuclear Training Department, including the Director of Nuclear Training, the Operations Training Manager, the Maintenance Training Manager, and the Technical Training Manager. Over the past year the new management team had brought in over a half dozen industry peer review teams to assist in assessing the progress in improving the training programs. PSE&G also issued new expectations for line management involvement in the training process and participation in each training department's Training Review Groups (TRGs). The inspector reviewed minutes from the last half year's TRG meetings for operations and technical training and interviewed several members of training, operations and engineering management, and concluded that line management's involvement in the training process had greatly improved and resulted in better self-assessments of the training programs.

In the interviews with Training Department management, the inspector determined that PSE&G took positive steps to resolve the weaknesses in training staff manning and performance. PSE&G had brought in a number of over-hires to supplement the previous training staff and instill a new perspective in the training staff. The inspector observed a number of licensed operator training sessions, both in the classroom and in the simulator, and concluded that the training staff performed well and that line management was very involved throughout the entire process. As one of the checks on training restart plan completion, the inspector verified the completeness of several qualification cards. The inspector compared the job assignments of several non-licensed operators, maintenance technicians and engineers with the qualifications and training completed by each person. The inspector determined that none of the personnel sampled were assigned to positions or responsibilities for which they were not qualified by documented training.

PSE&G addressed Problem Statement 4 of the Salem Engineering Restart Action Plan with corrective actions very similar to the actions of the training restart plan. In fact, responsibility for completing a majority of the engineering corrective actions had been assigned to the Nuclear Training Department. In order to improve engineer training and qualification, PSE&G planned on bench marking all engineering personnel qualifications, completing an engineering personnel job analysis, and developing a resultant engineering training and qualification matrix. PSE&G also intended to improve the engineering training programs to maintain the qualifications of the engineering staff at a high level. The inspector noted that the Nuclear Engineering Department had developed a training coordinator within the department, and that the Nuclear Training Department had moved the engineering training staff from the training center to the building which housed nuclear engineering staff in order to promote closer coordination between the training and line staffs. The inspector reviewed the new qualification and training matrix and the training programs PSE&G had developed to maintain the engineers' qualification and performance. The inspector determined that engineering personnel had been assigned to positions for which they were trained and qualified and that engineering and training management were coordinating and tracking engineer training in a manner to improve engineering performance.

The inspector attended the MRC meeting when the training staff presented the Training Restart Action Plan to the MRC for acceptance and closure. The Training Restart Action Plan was the first of the nine Salem restart plans to be brought before the MRC for closure. The training department intended the same presentation to be adequate to close the "Adequacy of Training" NRC Restart Issue. The inspector noted that the training department presentation was exceptionally brief (approximately 10 minutes) and only addressed the shortcomings of the licensed operator training program. The MRC did not ask any probing questions and yet accepted the training restart plan and the NRC restart issue as closed. The inspector concluded that the MRC performance had been relatively weak and did not justify the closure of the training plan. Subsequent to the MRC meeting, the inspector met with the Salem Projects Manager, who coordinates MRC activities, and discussed the inspector's concerns. The Projects Manager acknowledged the apparent shortcomings of the MRC performance but explained to the inspector the existence of extenuating circumstances. The Salem MRC had yielded responsibility for this restart plan to the Nuclear Training Oversight Committee (NTOC), a separate management team with a higher level of management on it than the MRC and whose sole responsibility was the oversight of the training programs. Through a review of MRC documentation, the inspector determined that the NTOC had maintained oversight of the training restart plan progress and had kept the MRC informed of their assessment of that progress. The inspector concluded that PSE&G management had in fact displayed the proper oversight of the implementation of the Training Restart Action Plan. Notwithstanding the inspector's conclusion, the Salem Projects Manager acknowledged the appearance of the MRC performance relative to restart action plan review and closure, and the Projects Manager issued new criteria for the MRC to use in assessing the closure of restart plans in the future.

The Salem UFSAR Section 13.2, "Training Program," states that the Nuclear Department training program is detailed in the training procedures manual. One of the procedures specifically referenced in Section 13.2 is Training Procedure 304, which describes the senior reactor operator training program. The inspector determined this reference was referring to training procedure TQ-TP.ZZ-0304(Q), "Senior Reactor Operator (SRO) Training Program." The inspector reviewed this procedure and determined that all assumptions and requirements of this procedure were being met by the Training Department's current programs. The inspector therefore concluded that this part of the training program complied with the UFSAR.

c. Conclusions

The inspector concluded that the Salem training programs had been greatly improved via the implementation of the Salem Training Restart Action Plan. Most notable were the improvements in the area of training program self-assessments and in the area of line management involvement in the training programs. PSE&G had evaluated the deficiencies in the training programs well and developed the training restart plan accordingly. The inspector's review determined that PSE&G had implemented that plan effectively and completely. In implementing the Training Restart Action Plan PSE&G had also satisfied the requirements of the Engineering Restart Action Plan Problem Statement 4. Despite the marginal performance of the MRC, the inspector concluded that the PSE&G completion and implementation of their Training Restart Action Plan was acceptable, and therefore, NRC Restart Issue III.16, "Adequacy of Training," is closed.

07 Quality Assurance in Operations

07.1 Corrective Actions for Salem Unit 2 Trip, NRC Restart Item II.43 (Open)

a. Inspection Scope (92901)

Inspectors reviewed the corrective actions to decide if they adequately addressed the causes of the Salem Unit 2 trip on June 7, 1995. The licensee review focused on the equipment-related causes specific to the Salem Unit 2 trip. The Salem Restart Plans address the broader issues leading to poor plant and staff performance.

b. Observations and Findings

Plant staff concluded that an actuation of Salem Unit 2 protective switchgear caused a turbine trip resulting in the reactor trip. The staff further concluded that an ineffective Operating Experience Feedback (OEF) program and ineffective response to vendor technical information resulted in failure to replace Struthers-Dunn SBF-1 relays prior June 1995. Salem addressed OEF corrective actions separately since a separate NRC inspection item addresses it and because different organizations have responsibility for OEF and vendor technical document reviews.

As a result, the package focused primarily on the vendor technical document reviews. The Significant Event Response Team (SERT) 95-02 report, the addendum to the report and the associated Licensee Event Report (LER) 95-04-01 identified a significant number of recommended actions, including the following with respect to vendor technical document review:

- Evaluate the history of all Struthers-Dunn relays and create a PM program;
- Perform an engineering review of the process for receipt, evaluation and routing of vendor and industry notifications;
- Replace all SBF-1 breaker failure relays on 13KV BS A-B, B-C, C-D, D-E with upgraded relays prior to restart; replace all SBF-1 breaker failure protection relays on 500KV breakers with upgraded relays with higher surge capability by 3-31-96;
- Perform a root cause evaluation for lack of prompt implementation of vendor recommendation to install upgraded relays (due 1-31-96);

The inspector found that the Management Review Committee considered the package closed without evidence that the plant staff completed the recommended actions. For example, the scheduled completion (7-15-96) for engineering review of the process for receipt, evaluation and routing of vendor and industry notifications occurred two weeks after MRC accepted closure of the package. The results of the review remained unavailable at the end of the inspection period. The inspector also noted that the closure package documented an audit of completion of the actions recommended in the SERT report and addendum, and in the LER. The inspector noted that the reviewers performed a thorough audit, and documented a number of discrepancies and incomplete recommendations. The MRC did not note or question the discrepancies.

c. Conclusions

Inspectors concluded that plant staff had not completed the actions to insure corrective action for the Salem Unit 2 trip of June 7, 1995. In addition, the Management Review Committee did not effectively insure a basis for closure of this issue.

O7.2 Quality of MRC Reviews

a. Inspection Scope (71707)

Inspectors assessed the MRC review effectiveness for closure of Salem technical and programmatic issues.

b. Findings and Observations

The MRC reviewed the closure package for NRC Restart Inspection Item II.18, Poor Reliability of Positive Displacement Charging Pumps in meeting 96-045 and approved it June 6, 1996. A subsequent review by the NRC lead to the following observations: Seven of fifteen corrective actions identified in the closure summary

as complete had no closure documents such as work orders, design changes, procedure changes, etc., to allow the MRC to confirm completion. The closure summary identified an additional seven of fifteen corrective action items as incomplete but provided no technical basis to justify closure of the issue or restart of the plant without their completion. In addition, the root cause analysis documents contained six recommended corrective actions with no discussion included in the package to explain whether these actions would be implemented.

As discussed in section O7.1, the MRC accepted the closure package for the Salem Unit 2 trip with no evidence (such as Work Orders) that plant staff completed corrective actions for SBF-1 relay problems. In addition, the closure package contained evidence that engineering had not completed an essential corrective action, assessment of the vendor technical document review program, yet MRC accepted the package.

c. Conclusions

The MRC did not consistently insure closure packages for identified technical and programmatic concerns demonstrated that plant staff had completed essential corrective actions.

O7.3 Operating Shifts

a. Inspection Scope (71707)

Inspectors reviewed a report made to comply with operating license requirements.

b. Observations and Findings

On August 8, Salem reported to the NRC that they had not submitted a license amendment when their operating shifts switched from eight hour shifts to twelve hour shifts. During a review of the license requirements (DPR-75 for Salem Unit 2) the licensee discovered that license condition 2.C. (24). a. required that, by June 3, 1981, PSE&G establish an eight hour operating shift to comply with NUREG 0737, item I.A.1.3. Salem Unit 2 complied with the requirement, however, in 1993 Salem Unit 2 transitioned to a twelve hour operating shift without requesting that the NRC change the license condition. The operating license for Salem Unit 1 did not contain the same condition. This item is unresolved pending further NRC review of the Salem licensee conditions (URI 50-272&311/96-08-06).

O7.4 Corrective Action Plan - Rules and Responsibilities, NRC Restart Item III.10.2 (Closed)

a. Inspection Scope (92903)

The inspector reviewed the licensee's actions to address problem statement No. 2 of their Corrective Action Restart Plan regarding: Roles and Responsibilities. This is

one of six subsections implemented to address weaknesses in the Corrective Action Program.

b. Observations and Findings

The inspector observed the Corrective Actions Group (CAG) presentation of this issue to the Management Review Committee (MRC) on May 30, 1996. Problem statement no. 2 identified that the Corrective Action Program (CAP) had no single point of accountability with respect to management ownership and oversight. It also noted that managers had not clearly defined roles, authorities, and responsibilities for administration of the program

In the spring of 1995, the NBU formed the CAG under a single manager, the Manager - Corrective Action and Quality Services (CA/QS) with a staff strictly to provide corrective action program oversight. Revision 9 of NAP-006, *Corrective Action Program*, initially defined their roles. The CAG discussed additional changes at the MRC and planned to further refine the CAG staff's roles and responsibilities.

c. Conclusion

Regarding problem statement No. 2, the inspector concluded that Manager, CA/QS satisfies the requirement for a single point of contact. The roles and responsibilities defined in NAP-006 are sufficient to address the second part of the problem statement . Since both of these items have been adequately addressed, this restart item (III.10.2 only) is closed.

II. Maintenance

M1 Conduct of Maintenance

M1.1 General Comments

Inspection Scope (62703)

The inspectors observed all or portions of the following work activities:

- 960729212: 125 VDC battery charger inspection/repair of terminal lugs
- 960314180: No. 21 spent fuel pit cooling pump motor bearing replacement
- 960701200: Rotation of no. 11 SI pump
- 960701177: Rotation of no. 21 SI pump

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

M1.2 Conduct of Maintenance

a. Inspection Scope (62703)

Salem maintenance staff continued to perform repairs that required a large amount of rework.

b. Observations and Findings

During the report period, Salem staff identified numerous examples of inadequate maintenance activities. Condition Resolutions (CRs) documented the following examples:

- Repeat work on the redundant air panel associated with 21MS171, CR 960806101;
- Repeat work on the Lunkenheimer valve associated with 22MS169, CR 960806125;
- Repeat work on the 2CVC excess letdown heat exchanger inlet valve (2CV131), CR 9960806081;
- Repeat corrective maintenance for the no. 2 polar crane pendant controls, CR 960806090; and
- Repeat work to replace the diaphragm for the 21SW63 valve, CR 960807210.

These CRs represent a small portion of the ineffective maintenance requiring repeat work. Salem management recognized the lack of maintenance effectiveness, in part, as a result of the Salem Integrated Readiness Assessment (SIRA), and documented the lack of effectiveness in CR 960801205. In addition, on July 22, 1996, PSE&G announced that the Salem unit 2 outage would continue well into the fourth quarter of 1996 to insure that the staff completes necessary work to insure safe, reliable plant operation. During the week of August 5, Salem managers initiated a plan to retrain all maintenance personnel during the remainder of 1996. In the interim, qualified contractors and Salem employees that pass performance examinations will perform Salem maintenance.

c. Conclusions

Salem and senior managers acknowledged continued poor maintenance staff performance. In response, the managers demonstrated their commitment to insuring safe reliable plant performance. The managers extended the Salem outage well into the fourth quarter of 1996, and initiated a program to retrain and re-qualify the entire Salem maintenance organization.

M2 Maintenance and Material Condition of Facilities and Equipment

M2.1 Adequacy of the Foreign Material Exclusion (FME) Program, NRC Restart Inspection Item III.5 (Open)

a. Inspection Scope

Inspectors reviewed procedure changes, training records, completed work packages, and made field observations to assess the effectiveness of the licensee corrective actions regarding the FME program.

b. Observations and Findings

The licensee described previous FME related performance with the following problem statement: "Weaknesses in our Foreign Material Exclusion (FME) practices had the potential to introduce foreign material into fluid systems or electrical components. Insufficient understanding of good FME practices by station supervisors and workers and inadequate FME procedures contributed to the problem."

PSE&G initiated several corrective actions to resolve the FME program shortcomings. Among the corrective actions:

- Revision of procedures which describe the FME process;
- Development and implementation of specialized FME training for new employees;
- FME training for the existing maintenance work force;
- Reinforcement of expectations on FME to the work force;
- Periodic reviews of FME practices; and
- Performance indicators to measure program effectiveness.

The FME closure package included a request to revise SC.MD-GP.ZZ-0006(Q), "Foreign Material Exclusion (FME) and Closure Control", to ensure an Action Request (AR) is written whenever FME integrity has been violated or is suspect. Procedure SC.MD-GP.ZZ-0006(Q), revision 7, dated July 1, 1996, however, requires an AR only "If the non-conformance CANNOT either be restored to an acceptable condition or replaced in kind". PSE&G responded to the inspectors' observation by initiating a procedure change request to require an AR for all FME non-conformances. (Reference Change Request R-15036)

The inspector reviewed FME trending information included in the closure package. This trend indicated a reduction in the number of FME occurrences per month since September, 1995. However, discussions with PSE&G personnel revealed that input data for the trending came from information contained in Action Requests which had been initiated since September. During that time period, there had been no requirement to initiate ARs for FME occurrences, therefore, the inspector considered the trend information inconclusive.

The inspector reviewed training records to verify that all maintenance department personnel had received the self-study material as indicated in the FME closure package. The records were difficult to retrieve, and in several cases, it was not possible to locate the records. PSE&G initiated AR 960801169 to identify and track resolution of this problem. PSE&G produced other training records that provided documentation that those personnel in question had received FME training other than the self-study material.

The inspector reviewed several field completed maintenance work packages. For each package, the documentation indicated FME controls and practices had been adequately implemented.

The inspector made observations of ongoing work activities within the plant. The inspector noted two examples where FME protective devices were used which were not authorized by procedure SC.MD-GP.ZZ-0006(Q), "Foreign Material Exclusion (FME) and Closure Control". Although the equipment involved was not safety related, the inspector concluded that since the procedure applied uniformly throughout the plant, there was potential for impact on safety related components. PSE&G responded to this observation by initiating AR 960801140 to identify and track this problem to resolution.

The inspector also found that entry control at the reactor vessel cavity FME boundary was not in strict compliance with procedures. The FME monitor at the boundary was allowing an individual with binoculars to enter and exit without being logged in or out, except for the initial entry at the beginning of the shift and final exit at the end of the shift. PSE&G corrected the immediate problem and initiated AR 960806222 to identify and track the procedure noncompliance issue.

The inspector noted two FME occurrences identified by PSE&G during the inspection period. One involved a hand tool which was dropped into the spent fuel pool as a result the tool not being secured properly. The second involved the discovery of pieces of carbon and stainless steel wire found in the reactor cavity following drain down. Both incidents are being tracked for resolution/corrective action by ARs.

The procedure violations noted above are considered additional examples of the failure to comply with procedure requirements which was identified in Notice of Violation 50-272,311/96-07-01 transmitted to PSE&G in a previous inspection report.

c. Conclusions

Although PSE&G has improved the FME program, significant problems continue to exist with implementation of the program. As a result, this inspection item remains open.

M4 Maintenance Staff Knowledge and Performance

M4.1 Post Maintenance Testing (PMT)

a. Inspection Scope (62703)

The inspector reviewed Maintenance's restoration of plant equipment following maintenance.

b. Observations and Findings

On June 3, 1996, maintenance technicians completed relay work on 21SW21, a diesel generator service water header supply valve. Maintenance returned the valve to Operations on June 5. On August 2, maintenance technicians performed a PMT and discovered the valve did not stroke from the control room. On August 2, the inspector identified that maintenance technicians did not perform the PMT prior to returning the 21SW21 valve to Operations. Failure to perform the required PMT is a violation of NC.NA-AP.ZZ-0009, *Work Control Process*, step 5.9.1.a. **(VIO 50-272&311/96-08-02)** Instrumentation and Controls (I&C) technicians determined that a single phase condition caused tripping of the motor operated valve thermal overloads.

Maintenance technicians completed a PM inspection on 2SJ68, safety injection minimum flow valve, on May 15, 1996. On August 2, Unit 2 control room operators discovered that they could not stroke the valve from the control room. An I&C supervisor identified that technicians did not conduct the PMT in May 1996. Technicians marked the PM procedure step not applicable (NA) that required valve stroke because the valve was tagged. Failure to perform the required PMT is another example of a violation of NC.NA-AP.ZZ-0009 as noted above. Instrumentation and Controls technicians identified a loose limit switch spring contact and attributed that condition to a weakness in the maintenance procedure.

In addition, the operations staff identified deficiencies with the planning, scheduling and performance of PMTs. For example, the staff initiated AR 960612155 (2B EDG PMT activities missing) and AR 960703142 (Inadequate PMTs for RVLIS and EHC system). The Operations Manager assigned a senior reactor operator to lead a 20-man task team to identify and correct PMT program deficiencies.

c. Conclusions

Maintenance technicians failed to perform required PMTs on safety-related valves. The Operations staff identified numerous deficiencies with the planning, scheduling and performance of PMTs.

M7 Quality Assurance in Maintenance Activities

M7.1 Housekeeping and Storage of Safety Related Materials

a. Inspection Scope (71707)

Inspectors toured the site to assess the adequacy of housekeeping and to determine compliance with the UFSAR section 17.2.2 commitment to Regulatory Guide 1.38, Quality Assurance Requirements for Packaging, Shipping, Receiving, Storage, and Handling of Items for Water Cooled Nuclear Power Plants.

b. Observations and Findings

During the inspection period the inspectors found numerous examples of poor housekeeping at Salem. Examples included trash, rain water, tools, litter, and miscellaneous equipment throughout the plant. The turbine deck contained make-shift storage areas that contained main generator parts completely immersed in water. The inspectors observed electrical extension cords too numerous to count. The inspectors found numerous chemical storage containers (spray cans, etc.), many of them empty, throughout the plant. On August 1, inspectors discovered numerous safety-related spare parts stored in a building near the service water intake structure. The parts included valve stems, bearings, gaskets, valve bodies, pipe, and other parts associate with the Service Water system. Many of the parts had labels requiring storage level C conditions, and a few parts required storage level B conditions. For example, the inspectors found a safety related shaft bearing, part J50207-000-220, associated with WO 90082011. The Regulatory Guide requirements for storage of level B and C materials include a fire resistant, tear resistant, weather tight, and well-ventilated building or equivalent enclosure. The building (and the storage racks outside of the building) was not fire resistant, weather-tight, or well-ventilated and did not protect the parts from the possibility of damage or lowering of quality due to corrosion, contamination, deterioration, or physical damage. Failure to meet the requirements for storage of level B and C safety-related materials is a violation. **(VIO 50-272&311/96-08-03).**

Salem and Nuclear Business Unit (NBU) managers independently identified poor housekeeping and gave considerable attention to it. In response, they initiated action to clean up the plant, dispose of the parts, and to emphasize supervisor and worker responsibility for plant cleanliness and safety. They also initiated CR 960731134, as required, to document a condition adverse to quality, and insure that they correct it.

c. Conclusions

The senior NBU managers and the inspectors independently identified that plant staff and contractors have not kept Salem clean. The inspectors identified that workers did not comply with requirements for storage of safety-related materials. The managers promptly took measures to clean the plant, dispose of the poorly

controlled materials, and emphasize their expectations for housekeeping and material controls.

III. Engineering

E2 Engineering Support of Facilities and Equipment

E2.1 NRC Restart Issue II.31 - Residual Heat Removal Discharge Valve (21RH10) Banging Noise (Closed)

a. Scope

The inspectors reviewed Salem engineering staff's determination for 21RH10 banging noises with no. 21 residual heat removal loop in service.

b. Observations and Findings

Salem engineers determined the cause was an out of tolerance valve stem arm combined with coolant flow through the valve. The flow rattled the valve disc against the valve seat. Engineers also noted, based on their review of work history documents, that disc noise was not unique to 21RH10. All RH10's exhibited rattling noises, with 21RH10 being the loudest.

The RH10 is a normally-open, eight inch, double disc (split wedge) gate valve. When the valve is open, the discs sit in the upper part of the valve body and have room for movement due to the loose tolerances due to the body casting. With flow through the valve, the bottom of the discs touch the flow stream and consequently the discs rattle against the downstream valve seat.

Plant staff took vibration data on all RH10's; 11&12RH10 on Unit 1, and 21&22RH10 on Unit 2. Based on the data, they opened and inspected 11, 21, and 22RH10. Valve 11RH10 dimensions checked out satisfactorily. The 21RH10 body was satisfactory, however, the disc stem arm dimensions were out of tolerance. Also, technicians could not weld repair wear indications on the downstream valve seat. They subsequently replaced valve 21RH10 with valve 11RH10. Technicians performed minor repairs to 22RH10, including replacement of a worn stem arm. The staff did not open 12RH10 because the vibration data did not indicate dimensions had deteriorated.

Engineers established a monitoring program for the valves. Technicians will open and inspect one valve, starting with 12RH10, each refueling outage. The inspections will continue unless the results indicate the inspections are unnecessary.

b. Conclusions

The inspectors concluded Salem engineers identified the cause of the banging noise for 21RH10 and took appropriate corrective action. Also, plant staff adequately addressed the generic issue and inspected the discharge valves for the remaining RHR loops, where warranted. This technical issue is closed.

E2.2 NRC Restart Issue II.34 - Safety Injection (SI) Pump Deficiencies (Open)

a. Scope

The inspectors reviewed Salem engineers' resolution of SI pump deficiencies.

b. Observations and Findings

Salem engineers reviewed the maintenance history, in service test data, and outstanding work items to determine whether the Salem staff had corrected SI pump deficiencies. The engineers noted the staff had corrected the deficiencies, and concluded the SI pumps would perform reliably.

Motor and pump vibration data were satisfactory for both Units' pumps, however, during this review engineers identified that no preventive task existed to periodically refurbish the motors. Engineers requested a recurring task for refurbishment every 10 years. As an immediate action, the staff refurbished two of the four motors. Of the remaining two motors, the staff will refurbish one prior to Unit 1 restart; the other does not warrant refurbishment (done in 1992).

Engineers also responded to industry experience with improperly fastened impeller locknuts. The staff disassembled all SI pumps and verified technicians had correctly fastened all locknuts. During reassembly, mechanics noted excessive shaft run out on both Unit 2 pumps. They successfully replaced both pumps and subsequently initiated a recurring task to rotate the SI pumps monthly until operators restart the respective Units.

The inspectors confirmed satisfactory SI pump and motor vibration data and that plant staff implemented monthly shaft rotations for idle SI pumps (Work Order 960701200 for no. 11 SI pump and Work Order 960701177 for no. 21 SI pump).

c. Conclusions

The inspectors concluded plant staff identified SI pump deficiencies. This item is still open, however, pending the results of operators conducting pump performance tests.

E2.3 NRC Restart Issue II.17 - Main Condenser Steam Dumps Malfunction (Open)

a. Scope

During a requalification training program inspection, NRC examiners observed operators on the simulator shut all main steam isolation valves (MSIVs) at a point where the EOPs did not direct them to do so. The operators acted, in part, because operation of the Salem units using the main condenser steam dumps causes an uncontrolled plant cooldown. The inspectors reviewed Salem staff's resolution of the operator performance and plant design issues.

b. Observations and Findings

Historically, balance of plant steam leaks were significant enough to cause the reactor cooldown rate to approach the Technical Specification limit of 100 degrees per hour. To compensate for this condition, operators adopted the unwritten practice of closing the MSIVs after a reactor trip to maintain the cooldown rate within regulations. The inspectors also noted that secondary plant steam leaks forced operators to perform plant startups with the MSIVs closed (instead of open, with the turbine stop valves closed).

The Salem staff addressed the procedure compliance and staff performance aspects of this restart issue through operator training. To correct EOP inadequacies, the staff revised steps that gave operators direction on whether to close the MSIVs.

The staff validated the revision and trained the operating crews. The inspector reviewed the new steps of the EOPs and concluded they were adequate, however, Salem staff has not yet issued the revision. The staff expected to issue the revision by September 1st.

c. Conclusions

Although the revised EOPs direct operators when to shut the MSIVs, the operators do not yet have the revision. Also, the Salem staff did not address why the operators could not operate the plant as designed following a reactor trip. Therefore, this item remains open.

E7 Quality Assurance in Engineering Activities

E7.1 Independent Assessment

a. Inspection Scope (71707)

Inspectors reviewed the results of the SIRA team to determine whether the team identified any safety or compliance concerns.

b. Observations and Findings

During the period June 3 to 23, an independent team assessed Salem performance in the areas of Operations, Maintenance and Surveillance, Engineering and Technical Support, and Management Programs and Independent Oversight.

The team concluded that five of the sixteen assessed Engineering areas were ready for restart. The team expected that another nine areas would be ready for restart. The two remaining areas, revalidation of the design bases and engineering staff knowledge of the design basis required significant improvement. In the details of the engineering assessment, the team identified several examples of engineering failure to meet code and regulatory requirements. The examples included:

- No evaluation for thermal expansion of chrome-moly replacement feed water piping as required by UFSAR commitment to ANSI-B31.1.
- Equivalent replacement of spiral wound asbestos filled gaskets with flexi-carb gaskets without a safety evaluation required by 10CFR50.59.
- Use of ASTM A-563 nuts in place of ASTM A-307 nuts without design reconciliation, as required by ASME XI.
- A temporary modification (removal of the motor operated valve 2SW26) without supporting calculations, and without consideration of the seismic effects on piping for the duration of the modification.

From June 21, when the SIRA team presented their findings until the inspector questioned the lack of a Condition Report on July 19, the Engineering staff failed to document the deficiencies as required by procedure NC.NA-AP.ZZ-0000(Q), *Action Request Process*, Rev. 0, step 5.2.6. This is a violation (**VIO 50-272&311/96-08-04**).

c. Conclusions

An independent assessment conducted by the Salem Integrated Readiness Assessment team concluded that, in general, Engineering appeared on the right track to support restart in a safe manner. Although the team identified four examples of inadequate engineering performance, the engineering staff did not initiate a Condition Resolution, as required, until questioned by an inspector.

E8 Miscellaneous Engineering Issues

E8.1 Potential for Vessel Head Cracking Due to Sulphur Intrusions in the Reactor Coolant System

Early in 1994, an inspection to identify any Primary Water Stress Corrosion Cracking (PWSCC) at the Jose Cabrera plant in Spain identified reactor vessel head penetration cracks which were apparently initiated by high sulfate levels in the reactor coolant system. In a letter to L.R. Eliason, dated May 9, 1996, NRC Region 1 requested that PSE&G conduct inspections or investigations as necessary to alleviate concerns on this topic regarding Salem Units 1 & 2.

a. Scope

PSE&G responded to the May 9, 1996 letter in a letter to the NRC dated June 10, 1996. In order to evaluate PSE&G's resolution of this concern, the inspector reviewed the response, documentation supporting the response, and plans for future actions.

b. Findings and Observations

The following items are from the itemized responses in the PSE&G letter and are organized to correspond to that letter. The descriptions are abbreviated for the purpose of this inspection report.

Item I.A

> "No high sulfur concentration as described in NSAL-94-028 or NRC Information Notice 96-11 have existed at Salem 1." (Note: NSAL-94-028 is a Westinghouse Report which addresses the same issue)

Item I.B

> "Two sulfur intrusions did occur at Salem 2." .... "These sulfur intrusions were from the equivalent of 7 liters of cation resin compared to the 200-300 liters reported at the Jose Cabrera plant."

The inspector reviewed PSE&G letter NE-95-0724 from R. Dolan, Principle Engineer - Chemistry Support which documented the history of the sulfur intrusions at Salem. The inspector found that the letter supported the information in Items I.A and I.B.

Item I.C

> "Salem 1 does have the Alloy 600 (Inconel) material described in NSAL 94-028, which experienced cracking at the Jose Cabrera plant, in the control rod drive mechanisms (CRDM) penetration." "...the Alloy 600 used in Salem 1 is more susceptible to sensitization than the alloy used in Salem 2." "PSE&G Engineering is monitoring experience from other plants with alloy 600, especially detailed inspection results, to determine if any additional actions are appropriate for Salem 1 and 2."

The inspector reviewed Westinghouse Report NSAL-94-028 and PSE&G letters MEC-95-528 and NE-95-0724 on the subject of PWSCC. In addition, the inspector met with engineering personnel regarding the monitoring of experience from other plants regarding this subject. The inspector found that information contained in the letters was consistent with the response letter and that the plan for monitoring experience at other plants on this issue is adequate.

Item I.D

> "...the Salem In service Inspection (ISI) Department performs visual inspections and ultrasonic testing of the reactor vessel head during refueling outages to provide assurance that any cracks or leaks are identified." "Visual inspections of the reactor vessel for leakage are also performed in Mode 3 during plant startups..."

The inspector reviewed procedure SC.RA-IS.ZZ-0006(Q), VT-2 System Leakage Visual Exams for Nuclear Class I, II, & III Systems and procedure OP-PT.CAN-0001, Containment Walkdown. The inspector noted that although these procedures provided adequate guidance for leakage detection, neither procedure provides for crack detection by ultrasonic testing, dye penetrant testing or eddy current testing for the CRDM penetrations. Further research determined that the NRC has accepted the position that visual inspection is acceptable for crack detection regarding the CRDM penetrations. This position was stated in an NRC letter dated November 19, 1993 from William T. Russell to NUMARC.

The inspector discussed the results of past inspections for vessel head leaks/cracking with a member of the ISI Group in Specialty Engineering and learned that, to date, no cracking has been found.

Item I.E

> "CRDM penetration cracking has been analyzed by Westinghouse and it has been determined that even if such cracking is present it is not a substantial safety hazard (NSAL-94-028)."

The inspector confirmed that the NRC has previously agreed with the position that there are no unreviewed safety questions associated with CRDM penetration cracking. That position is documented in the NRC November 19, 1993 letter referred to in the discussion of Item I.D above. The inspector agrees that the CRDM penetration cracking issue is not a substantial safety hazard.

c. Conclusions

The inspector found that the documentation reviewed at the Salem site validates the information provided in the PSE&G response regarding potential for CRDM penetration cracking. In addition, the inspector concluded that the planned visual inspections of the vessel head are adequate for detecting any cracks. This issue is closed.

E8.2 Steam Generator Replacement

a. Inspection Scope (37551)

Inspectors reviewed the Steam Generator Replacement Project (SGRP) and parts of the Salem FSAR project on 7/23-7/26 and 8/8-8/9/96.

b. Observations and Findings

On June 27, 1996, PSE&G met with NRC staff in Rockville, Maryland to present their plan to replace the four steam generators of Salem Unit 1 with unused steam generators from the canceled Seabrook Unit 2 plant. During the week of July 22, 1996 inspection was conducted at the Salem plant of the project staffing, preliminary steam generator replacement (SGRP) planning, organization of the project, engineering involvement and related project Quality Assurance. As of that time, work had initiated at the Seabrook Unit 2 in preparation to remove the replacement steam generators (RSG). The work scope at Seabrook includes tube quality verification by eddy current testing, pipe cutting, machining, welding, rigging and lifting, and hydrostatic pressure testing. Onsite inspection by NRC of a portion of the work on RSGs at Seabrook is planned during August and September. An objective of the inspection at the Salem plant was to determine the project overview and schedule for planning inspection coverage of the steam generator replacement process.

At the Salem site, the project team had been established and preliminary planning and scheduling of the SGRP work was in progress. The engineering/licensing analyses work planned to establish the significance of changes induced by the SGRP project includes a review of the FSAR Chapter 15 accident analyses, steam generator performance calculations, qualification of the NSSS and support loads, an evaluation of operational transients, operational evaluations, and operator training support. At this preliminary stage of the SGRP, no firm conclusions were reached by the inspector, however no items of concern were identified.

E8.3 Extended Layup of Unit 1 Systems

a. Inspection Scope (92901)

The NRC reviewed licensee actions to preserve the Salem Unit 1 facility pending replacement of the steam generators. Proper layup of plant systems during the shutdown could reduce challenges to operators during the subsequent startup. The licensee shut Unit 1 down in May, 1995 and expected it to remain shutdown through the remainder of 1996. The inspector reviewed associated procedures and documentation, performed system walkdowns and interviewed key personnel.

b. Observations and Findings

In June, 1995, Salem assigned a chemistry supervisor the responsibility to coordinate and implement the layup program. Chemistry staff developed a Salem Department Directive SC.CH-DD.ZZ-0003(Q), *Plant Layup for Salem Chemistry*, to provide guidance for layup of the steam generators, the feed and condensate system, and the demineralizer plant. System engineers developed recommendations for layup of other portions of the facility and provided them to the layup coordinator in a series of memos from the System Engineering Manager.

At the time of the inspection, plant staff had almost completely implemented the secondary system drying with 20 desiccant dehumidifiers installed to control system humidity. A staff of two full time technicians tended to the desiccant dehumidifiers, perform walkdowns and log performance data weekly. The technicians trended flow rates and humidity readings from various system vent points to assure dehumidification. One challenge to the secondary layup program was maintaining the correct system valve lineup.

Chemistry technicians established the secondary system lineups using a work request and requesting operations to position specific valves. Operations positioned the valves and updated the positions in the TRIS. However, no mechanism existed to assure secondary system valves will remain in position for the remainder of the outage. Problems resulted from small bore piping replacement where workers removed and replaced valves, then returned to the normal system lineup vice the layup position. Chemistry staff implemented technician walkdowns and system performance trending to maintain the required system configuration.

NRC walkdown identified that plant staff had laid up the sections of piping from the condensate pump suction to the hot well with flow through a vent point as desired. This configuration resulted in a significant section of piping in the low point of the system with no flow through it to promote drying and without monitoring to assure the piping remained dry and un-isolated. As a result of the inspector's observations Chemistry staff requested that operators establish the vent point and added the valves to their list for sampling and trending.

The inspector reviewed the system engineering recommendations and considered them comprehensive. The layup recommendations acknowledged planned maintenance activities prior to restart and summarized the systems required to remain available during the layup period. However, the system engineering memos made numerous recommendations that plant staff did not fully implement. Examples included monthly rotation of various pumps such as auxiliary feed, residual heat removal and containment spray; removal and dry storage of the traveling water screens and circulating water pumps; heating and desiccant application in electrical cabinets; weekly operation of the turbine oil system and rotation of the turbine. The layup coordinator continued to pursue implementing procedures and work requests to establish the desired layup activities. However, the inspector noted that the system engineering staff did not aggressively chase completion of the recommendations or establishment of alternate conditions.

Operators had defueled the reactor and drained the primary system as much as possible. Although system engineers recommended sampling of the stagnant water remaining in the reactor vessel, plant staff had not yet developed a procedure to obtain the samples. Engineers also recommended that the reactor vessel level indicating system (RVLIS) should have water on the process side to prevent damage to the seals. The inspector noted that the current plant conditions did not provide for wetting of the RVLIS seals. At the end of the inspection period, the licensee had not determined the proper course of action regarding RVLIS layup.

c. Conclusions

The inspector concluded that engineering provided a detailed list of recommendations for laying up various systems and components. However, plant staff had not developed a comprehensive plan for plant layup that integrated the various recommendations. The system engineers did not actively identify and resolve deviations from their recommendations. Plant staff had nearly completed layup and drying of secondary systems with a trending program in place to monitor performance. However, the inspector identified a significant portion of piping in the low point of the system that they had not included in the trending program. Although control of the valve lineup for system drying was weak, the trending program should provide an adequate indication of system configuration.

E8.4 Spent Fuel Pool Cooling and Refueling Activities

a. Findings and Conclusions

Inspectors performed a survey of spent fuel practices and spent fuel pool (SFP) cooling system design and current licensing basis was performed on March 28 and 29, 1996. The NRC published the results of this survey in NRC Inspection Report No. 50-272 and 50-311/96-05. The survey identified four discrepancies that the licensee committed to resolve. A letter dated June 27, 1996, was sent to the licensee requesting that the licensee confirm these commitments and indicate the projected completion date for each of the actions.

Specifically, the licensee committed to:

(1) Update the current licensing basis to state that a full core off-load is the routine practice during refueling outages (IFI 50-272&311/96-08-07).

(2) Perform an analysis of the SFP structures and associated systems to consider SFP water temperatures above 180 F (IFI 50-272&311/96-08-08).

(3) Develop a procedure for using the cross connect between the heat exchangers to support the one unit with the SFP excess heat load (IFI 50-272&311/96-08-09).

(4) Put in place procedural controls that will assure that the SFP heat load is maintained below the analyzed value (IFI 50-272&311/96-08-10).

Inspectors will inspect licensee implementation of the commitments during routine inspection activities.

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 August 14, 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.

INSPECTION PROCEDURES USED

IP 61726:	Surveillance Observations
IP 62703:	Maintenance Observations
IP 71707:	Plant Operations
IP 92901:	Followup - Plant Operations
IP 92903:	Followup - Engineering

ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

50-272&311/96-08-01	VIO	Ineffective Tagging Request Inquiry System updates
50-272&311/96-08-02	VIO	Failure to perform post maintenance testing
50-272&311/96-08-03	VIO	Inadequate safety-related material storage
50-272&311/96-08-04	VIO	Failure to initiate Condition Resolution reports (App B, Criterion XVI)
50-272&311/96-08-05	VIO	Failure to Provide Adequate Operating Procedures
50-272&311/96-08-06	URI	Review Salem License Conditions
50-272&311/96-08-07	IFIs	Refuel Practices Commitments
50-272&311/96-08-08	IFIs	Refuel Practices Commitments
50-272&311/96-08-09	IFIs	Refuel Practices Commitments
50-272&311/96-08-10	IFIs	Refuel Practices Commitments.

LIST OF ACRONYMS USED

AFW	Auxiliary Feedwater
AR	Action Request
CAG	Corrective Action Group
CAP	Corrective Action Program
CA/QS	Corrective Action and Quality Services
CCHX	Component Cooling Heat Exchanger
CRDM	Control Rod Drive Mechanisms
CRs	Condition Reports
CVC	Centrifugal Charging
ECAC	Emergency Control Air Compressor
EDG	Emergency Diesel Generator
EOPs	Emergency Operating Procedures
ERG	Emergency Response Guideline
FME	Foreign Material Exclusion
HDI	Hilti Drop-In
I&C	Instrumentation and Controls
INPO	Institute of Nuclear Power Operations
ISI	Inservice Inspection
LER	Licensee Event Report
MRC	Management Review Committee
MSIVs	Main Steam Isolation Valves
N/A	Not Applicable
NBU	Nuclear Business Unit
NRC	Nuclear Regulatory Commission
NTOC	Nuclear Training Oversight Committee
OD	Operability Determinations
OEF	Operating Experience Feedback
OTSC	On-The-Spot Change
PDR	Public Document Room
PMT	Post-Maintenance Testing
PSE&G	Public Service Electric and Gas
PWSCC	Primary Water Stress Corrosion Cracking
RCP	Reactor Coolant Pump
RCS	Reactor Coolant System
RHR	Residual Heat Removal
RVLIS	Reactor Vessel Level Indicating System
SERT	Significant Event Response Team
SI	Safety Injection
SIRA	Salem Integrated Readiness Assessment
SNSS	Senior Nuclear Shift Supervisor
SORC	Station Operations Review Committee
SRG	Safety Review Group
SRO	Senior Reactor Operator
SW	Service Water
TDR	Technical Document Room
TRGs	Training Review Group
TRIS	Tagging Request Inquiry System
TS	Technical Specification
UFSAR	Updated Final Safety Analyses Report