U. S. NUCLEAR REGULATORY COMMISSION

REGION I

Docket Nos: 50-272, 50-311
License Nos: DPR-70, DPR-75

Report No. 50-272/97-03, 50-311/97-03

Licensee: Public Service Electric and Gas Company

Facility: Salem Nuclear Generating Station, Units 1 & 2

Location: P.O. Box 236
Hancocks Bridge, New Jersey 08038

Dates: January 26, 1997 - March 15, 1997

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EXECUTIVE SUMMARY

Salem Nuclear Generating Station
NRC Inspection Report 50-272/97-03, 50-311/97-03

This integrated inspection included aspects of licensee operations, engineering, maintenance, and plant support. The report covers a 7-week period of resident inspection. In addition, it includes the results of inspections of steam generator replacement, the Motor-operated valve program, and the commitment management system.

Operations

Operators continued to demonstrate deliberate control of plant activities and conservative decision-making. Unit 2 operators demonstrated good awareness of technical specification requirements in controlling pressurizer auxiliary spray even though a surveillance procedure did not provide appropriate precautions (Section O3.2). Although the inspectors observed good overall operator performance, the inspectors noted some weaknesses involving use of the alarm response procedures, evaluation of an off-normal plant condition, and shift turnovers (Section O4.2). Plant managers demonstrated leadership and commitment to excellence in demanding that containment inspection teams implement higher standards for containment cleanliness and material condition (Section O8.2).

The station implemented a number of programs designed to enhance procedure use and adequacy. Recent inspection observations indicate good and improving procedure use. Procedures were reviewed and revised in key station functional areas. The operations staff appropriately identified operations procedures that required revision prior to restart. Selected procedures reviewed appeared adequate and generally consistent with the procedure writers guide. The inspector concluded that procedure use and adherence is adequate (Section O3.1). Implementation of effective operability determination training for operations and system engineering staff resulted in an effective process for developing operability determinations (Section O2.1).

The operations staff implemented extensive corrective measures resulting in significant improvement in operator performance since June 1995. Operators demonstrated safety-conscious decision making, ownership for plant equipment, detailed knowledge of plant operation, a good questioning attitude, effective communications, procedure compliance, low tolerance for workarounds, and a tendency to identify and correct deficient conditions. The inspectors considered the measures to improve performance effective (Section O4.1). The operations staff also established, implemented and completed the Operations Restart Action Plan. Inspectors considered the results of the completed actions effective in improving: oversight of plant activities, operator training, standards for equipment condition, communication, and control of plant operation (Section O8.1).

In a letter dated March 18, 1997, NRC issued a violation for two aspects of licensed operator requalification training that did not meet 10 CFR 55.59(c) based on licensee submittals dated November 7, 1996, January 6, 1997, and February 12, 1997. The two aspects related to compliance with requirements for an annual operating test for all operators and for continuous requalification training programs not to exceed 2 years in duration. The NRC letter also noted that the operator training has been high quality and effective, but the violation represents weak program planning (Section O5).

The inspectors concluded that Salem radiation monitors and procedures adequately addressed the requirements of 10 CFR 70.24 for criticality monitors (Section O8.3). An independent investigation, in response to a employee concern, effectively demonstrated that Quality Assurance (QA) management actions had not resulted in toning down QA inspector findings. The investigation also effectively demonstrated that QA managers had not taken action to reprimand or otherwise penalize QA inspectors as a result of the QA inspectors' findings (Section O8.4). The licensee developed and improved their methods for commitment management (e.g. Commitment Manager and the 30-day look ahead report), informed responsible personnel of these methods and management expectations, and began to improve commitment management procedures. The NRC Restart Item (III.14) remains open pending completion of the procedure changes (Section O8.5).

Maintenance

The maintenance restart action plan effectively addressed previous performance deficiencies. The inspectors found that management monitored emergent work and actively participated in the assignment of priorities to safety significant work. Maintenance personnel identified new problems and initiated corrective action. For the activities observed, maintenance technicians used procedures and tools properly. Management actively monitored performance using trending tools and self assessments. Additionally, QA provided useful performance assessment. The self assessments and QA assessments enabled management to continue to improve maintenance performance. Although performance deficiencies continue to occur, significant reduction in the error rate and significant improvement in equipment performance indicated that implementation of the maintenance restart plan resulted in effective maintenance (Section M1.2).

Inspectors noted that good quality generally characterized the performance of the Salem Unit 1 steam generator replacement project (SGRP). When workers identified problems, the managers and supervisors stopped or delayed work until they established an acceptable course of action (Section M1.3). Technicians demonstrated good procedure adherence during repair of the 1C EDG jacket cooling leak, and during replacement of the 11 SW pump. Troubleshooting of the 1C EDG frequency variations was logical. Weak engineering controls were established prior to changing the type of packing in the 11 SW pump (Section M1.4). Maintenance did not effectively repair a packing leak or adequately use equipment malfunction identification system tag tracking. Maintenance and engineering did not adequately support operations in resolving diesel day tank level indication inadequacies (Section M2.1). Technicians properly controlled and conducted safety-related maintenance on the no. 23 component cooling water pump (Section M3.1).

Salem management has improved, and continues to improve, work control effectiveness. They improved the process, trained personnel, and increased staffing levels in the planning and scheduling group. PSE&G's staff addressed the work order backlog and they are using performance indicators to monitor progress. While personnel could still improve their performance, the work control staff's response to their self assessment indicated to the inspector that management would ensure the organization continued to address deficiencies. The inspector concluded the work control program is ready to support Salem restart (Section M8.1).

Engineering

Significant progress and improvements in the MOV program were evident since the last NRC inspection of July 1996. The justifications for key program assumptions were complete and the applied valve factors of Salem Unit 2 MOVs were adequate for GL 89-10 closure, demonstrating design-basis capability. These conclusions were based on the understanding that PSE&G would pursue additional actions for certain MOVs in Families 6 and 9 in conjunction with their periodic verification program (Sections E1.3 and E1.4). PSE&G's actions to address pressure locking and thermal binding of motor-operated gate valves were acceptable (Section E1.5). PSE&G had developed a good tracking and trending program and was adequately addressing MOV performance problems (Section E1.6).

Inspectors observed generally good engineering performance during the period with occasional lapses. During review of an operability determination, station operations review committee (SORC) members questioned the basis for assurance that containment fan coil unit (CFCU) modifications did not affect containment integrity. The plant staff did not address the SORC question, and station management demonstrated lack of follow through by not ensuring that the plant staff developed a satisfactory response to the containment integrity question. In response to inspector questions, and prior to entering the affected mode, SORC approved a 10 CFR 50.59 safety evaluation that adequately addressed the concern regarding the UFSAR commitments for Type C leak rate testing the CFCU SW cooling line containment isolation valves (Section E1.9). As a result of a proposed modification, an alert system manager discovered an incomplete surveillance of the circuit for automatic operation of the Pressurizer Overpressure Protection System. The plant staff immediately devised and completed an effective test. The inspectors noted that TSSIP, phase 2, scheduled for completion in late 1997, would have discovered this deficiency (Section E1.10). The engineering staff conducted appropriate trouble-shooting to determine the cause of control room ventilation performance problems. The Salem managers properly elected to correct system deficiencies rather than change the licensing basis for control room ventilation. As a result of considerable effort, the engineering staff successfully demonstrated the ability of control room ventilation to perform its design function (Section E8.1)

Pending satisfactory implementation of the modifications to address the effects of multiple hot shorts on safe shutdown, the associated NRC Restart Item and Unresolved Items will remain open (Section E8.3).

Plant Support

Inspectors concluded that PSE&G had adequately addressed various open items relating to Emergency Preparedness.

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Report Details

Summary of Plant Status

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

Operators maintained Unit 2 in Mode 5, Cold Shutdown, for the duration of the period.

I. Operations

O1 Conduct of Operations

O1.1 General Comments (71707)

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

O2 Operational Status of Facilities and Equipment

O2.1 Operability Determinations, NRC Restart Item III.6 (Closed) and Unresolved Item 50-272&311/95-80-01 (Closed)

a. Inspection Scope (71707)

Various NRC Inspection Reports, such as 50-272&311/95-80, documented unacceptable and poor quality operability determinations at Salem. The inability of the Salem staff, in the past, to appropriately determine equipment operability contributed significantly to the cause of the shut down of Salem Units 1 and 2 in 1995. In NRC Inspection Report 50-272&311/96-08, section O2.1, the inspectors reviewed Salem's method for assessing the operability of degraded or nonconforming structures, systems, and components. The inspectors concluded that the new operability determination process provided clear guidance for documenting and tracking the operability of degraded or nonconforming equipment. The inspectors noted, however, that operations and system engineering staff had not received training on implementation of the new system. As a result, the inspectors left NRC Restart Item III.6 open at that time.

b. Observations and Findings

The inspectors verified that operations and system engineering staff had received training on implementation of the new system. In addition, the inspectors reviewed several recent operability determinations and observed the staff presentations of operability determinations to SORC. The inspectors noted that the station staff presented comprehensive operability determinations that included consideration of design and licensing basis information pertinent to the equipment evaluated in the operability determination. The presentations included operability determinations for component cooling water room coolers, containment fan coil units, and others. The inspectors considered the operability determinations acceptable.

c. Conclusions

The inspectors concluded that implementation of effective operability determination training for operations and system engineering staff resulted in an effective process for developing operability determinations.

O3 Operations Procedures and Documentation

O3.1 Procedure Use And Adequacy - NRC Restart Item III.3 (Closed)

a. Inspection Scope (92901)

The inspector reviewed the licensee's actions to address problems with the use and adequacy of procedures.

b. Observations and Findings

Procedure Adherence

Salem implemented several initiatives to improve performance in procedure adherence including:

- Site and departmental management reinforced procedure use expectations through memorandums and site messages.
- Salem staff upgraded procedure use instructions in several areas.
- Plant staff conducted procedure use training for operations and maintenance department personnel.

The inspector concluded that these actions improved procedure adherence. The inspector performed several observations and reviewed the recent inspection record to determine the effectiveness of these actions. Recent inspection reports (96-15, 96-17, 96-18) noted generally good and improving procedure adherence performance. Inspectors also noted good procedure adherence for operations and maintenance activities monitored this period.

Procedure Adequacy

The licensee reviewed procedures in the station operations, maintenance, chemistry, radiological protection, and engineering areas. Plant staff revised or validated a number of operations procedures including the abnormal, emergency, alarm response, and integrated operating procedures. They also upgraded maintenance troubleshooting, Hagan module configuration and calibration, and foreign material exclusion control procedures. Plant staff targeted specific enhancements for chemistry and radiological procedures.

Salem staff updated the procedure writer and reviewer's guide, and developed a program to train procedure writers on the new guide. The licensee recently identified additional chemistry procedure enhancements to remove statements that could lead to mis-interpretation. The licensee reviewed the procedure revision backlog in the operations, maintenance, chemistry and radiological areas and identified the procedures that required revision prior to restart.

The inspector reviewed a portion of the operations procedure backlog and did not identify any procedures that required revision prior to restart. Additionally, the inspector reviewed normal operating procedures and did not identify any technical deficiencies. Maintenance procedures reviewed during plant observations appeared adequate.

c. Conclusions

The station has implemented a number of programs designed to enhance procedure use and adequacy. Recent inspection observations indicate good and improving procedure use. Plant staff reviewed and revised procedures in key station functional areas. They appropriately identified corrected operations procedures that required revision prior to restart. The inspector considered sampled procedures adequate and generally consistent with the procedure writer's guide. The inspector considered procedure use and adherence adequate.

O3.2 Control of Pressurizer Auxiliary Spray (71707)

On March 11, Unit 2 operators stroked 2CV75 (auxiliary spray valve) in accordance with S2.OP-ST.CVC-0007, *Inservice Testing Chemical and Volume Control Valves in Modes 5 and 6*. The reactor operator ensured that spray differential temperature did not exceed 320°F as specified in Technical Specification 3.4.10.2.C. The inspector noted, however, that S2.OP-ST.CVC-0007 did not provide guidance to prevent operators from exceeding a 320°F differential temperature and impacting pressurizer spray nozzle fracture toughness. The reactor operator initiated a procedure revision request to improve S2.OP-ST.CVC-0007. The inspector concluded that operators demonstrated good awareness of technical specification requirements and ensured plant operation within specified limits despite lack of procedure guidance to limit the differential temperature.

O4 Operator Knowledge and Performance

O4.1 Operator Performance, NRC Restart Item III.7 (Closed)

a. Inspection Scope (92901)

The inspector reviewed corrective actions to address operator performance weaknesses. The inspector assessed operator performance relative to the restart of the Salem units.

b. Observations and Findings

Starting in June 1995, the operations manager acted to increase operations staffing, improve operator training, and raise operator standards. The operations manager strengthened shift resources through increased shift technical advisor (STA) staffing, hiring seven previously licensed senior reactor operators (SROs) with significant operating experience, and balancing operating crews based on strengths, weaknesses, and personalities. The operations and training staff developed and implemented a comprehensive two phase training program to improve operator performance. The first phase involved a comprehensive assessment of licensed operator knowledge, skills, and attitudes through written, oral, and performance evaluations. The second phase contained training specifically targeting phase one weaknesses and involved approximately 500 contact hours. The training focused not only on knowledge and skills, but on affecting the cultural shift needed for safe plant operations.

In recent inspection reports (50-272 and 311/96-17 and 96-18), inspectors documented good performance in the following areas:

- risk management and safety focus,
- technical specification compliance,
- intolerance for workarounds,
- identification of degraded conditions and timely corrective action,
- procedure compliance,
- operator knowledge,
- questioning attitude,
- communication and coordination,
- plant ownership, and
- awareness of plant equipment status.

Although operator performance continued to improve since June 1995, operators periodically failed to meet management expectations and, on occasion, NRC requirements. Operations management's prompt and comprehensive corrective actions for past errors reduced the frequency and consequences of similar performance lapses. For example, on January 2, 1997, operators experienced a problem with reactor coolant system (RCS) level indication as a result of an operator-induced valve misalignment during the RCS fill and vent. Operators immediately recognized and responded to the problem as a result of their focus on RCS level. Operations management immediately took comprehensive corrective action. The valve misalignment had no safety consequence.

c. Conclusions

Operations management implemented extensive corrective measures and affected significant improvement in operator performance since June 1995. Operators demonstrated safety-conscious decision making, ownership for plant equipment, detailed knowledge of plant operation, a good questioning attitude, effective communications, procedure compliance, an intolerance for workarounds, and a propensity to identify and correct deficient conditions. Operator performance supports restart of the Salem units.

O4.2 Routine Operator Performance Observations

a. Inspection Scope (71707)

The inspectors observed the control room operators perform routine plant activities including transfer of the operating Unit 2 residual heat removal (RHR) heat exchanger in accordance with S2.OP-SO.RHR-0001, "Initiating RHR" and response to a low ambient temperature condition in the Unit 1 and Unit 2 service water (SW) pump bays.

b. Observations and Findings

Transferring Residual Heat Removal Loops - Unit 2

The inspectors observed that a reactor coolant pump (RCP) bearing low cooling flow alarm repeatedly actuated and cleared during transfer of the operating Unit 2 RHR heat exchanger. The control room operator (CRO) attributed the alarm condition to aligning the component cooling water (CCW) flow into the standby RHR system heat exchanger. The CRO did not refer to the alarm response card (ARC) and completed transferring the RHR heat exchangers. The RCP cooling flow alarm promptly cleared upon completion of the transfer evolution, demonstrating that the alarm did not represent a degraded condition. The inspector considered that not referring to the alarm response card demonstrated a poor operator practice. The inspector did not identify any other operator deficiencies during the evolution. The system manager and the assistant operations manager indicated that they would review the S2.OP-SO.RHR-0001 procedure to determine if the RHR heat exchangers could be transferred with less impact on the CCW system flow.

Low Service Water Pump Bay Ambient Temperature Readings

The inspector noted that the logged 1 and 2 SW pump bay ambient temperatures were between 50 and 58°F during a two day period. The minimum specified log temperature for these rooms was 60°F. The plant operators properly identified and circled the out of specification log readings, and verified that an active action request existed to address the cause for the low room temperature conditions.

The nuclear shift supervisor (NSS) did not know whether the low temperature condition had been evaluated to ensure that the safety-related components in the SW pump bays remained operable. The inspector reviewed the Updated Final Safety Analysis Report (UFSAR), Section 9.4.7.1, and noted that the SW pump bay room had a low ambient temperature alarm setpoint of 40°F and concluded that the recorded SW pump bay temperatures did not exceed the room ambient temperature design limits.

The inspector discussed this observation with the Operations Manager and learned that a previous shift had evaluated the impact of the low temperature condition on the operability of components. The inspector concluded that NSS's lack of familiarity with this evaluation demonstrated weaknesses in the evaluation of off-normal plant conditions and the communication of information during shift turnovers.

c. Conclusions

The inspector concluded that although routine operator performance is generally good; some weaknesses were noted involving use of the alarm response cards, evaluation of an off-normal plant condition, and shift turnovers.

O5 Operator Training and Qualification

In a letter dated March 18, 1997, NRC issued a violation for two aspects of licensed operator requalification training that did not meet 10 CFR 55.59(c) based on licensee submittals dated November 7, 1996, January 6, 1997, and February 12, 1997. The two aspects related to compliance with requirements for an annual operating test for all operators and for continuous requalification training programs not to exceed 2 years in duration. The NRC letter also noted that the operator training has been high quality and effective, but the violation represents weak program planning. For follow-up purposes, this violation will be numbered as **VIO 50-272&311/97-03-01.**

O8 Miscellaneous Operations Issue

O8.1 Operations Restart Action Plan (Closed)

a. Inspection Scope (92901)

The Salem Operations Restart Action Plan established a performance based approach to specify and control the actions required to demonstrate operations restart readiness. The inspector reviewed operations implementation of their restart plan and assessed operations readiness for restart.

b. Observations and Findings

The Operations Manager identified six major areas for improvement, and developed six problem statements to describe the weaknesses and outline corrective actions. The inspector closed problem statements nos. 1, 2, 3, and 6 in inspection report 50-272 and 311/ 96-18.

Problem statement no. 4 identified that operations procedures and policies need to be strengthened to support long-term operational excellence and plant startup. The inspector reviewed operations' corrective actions and concluded that the adequacy and use of procedures supported restart of the Salem units (see section O3.1). The inspector considered the actions to address problem statement no. 4 adequate to support restart.

Problem statement no. 5 identified that operations' ownership for skills, knowledge, attitude and training of operators needed significant improvement. Inspectors reviewed the adequacy of training, NRC Restart Item III.16, in inspection report 50-272 and 50-311/ 96-08. Inspectors concluded that 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. The inspector considered the actions to address problem statement no. 5 adequate to support restart.

c. Conclusions

Operations established, implemented, and completed an effective restart action plan to demonstrate operations' readiness for restart of both Salem units.

O8.2 Containment Cleanliness (71707)

The inspector assessed the Unit 2 containment material condition and housekeeping as plant staff prepared for mode 4, Hot Shutdown, operation. Early in the period, five "sparkle" teams led by radiation protection identified approximately 200 minor deficiencies. The Operations Manager and QA/NSR Director spearheaded a management effort to upgrade standards concerning plant material condition. Plant management set higher standards for the inspection teams and the teams identified 60 additional containment deficiencies. Further management guidance and direct inspection effort resulted in 40 more documented deficiencies. The inspection teams identified and removed a significant amount of small debris including paint chips, plastic bags, loose lagging, tape, cable ties, and discrepancy tags. Plant management planned to apply the same high level inspection effort to the remainder of the Salem facility. The inspector noted that plant managers successfully accomplished two goals: they significantly raised the standards for acceptable plant cleanliness, and they successfully implemented the standards in the Salem Unit 2 containment.

O8.3 Criticality Monitors

a. Inspection Scope (71707)

The inspectors reviewed the Salem Unit 1 and Unit 2 plant design to determine compliance with the requirements of 10 CFR 70.24.

b. Observations and Findings

The Salem UFSAR, section 12.1.3.6, states: "A Geiger-Mueller, or equivalent monitor is located on the operating deck floor (Elevation 130 feet) of each Fuel Handling Building. These monitors are sensitive to gamma radiation and are alarmed in accordance with NRC Regulation 10 CFR 70.24. The alarm will sound locally and in the control room." The UFSAR also states that Salem staff has written comprehensive emergency procedures to ensure that all personnel withdraw upon the sounding of the alarm to a designated area of safety. The inspectors verified installation of the radiation monitors (1R5 and 1R9 for Unit 1, 2R5 and 2R9 for Unit 2) described in the UFSAR. The engineering staff verified that the alarm setpoints for the radiation monitors met requirements of 10 CFR 70.24 a(1) for both Salem units. The Salem Operating Procedures and Emergency Plan Implementing Procedures contain procedures to evacuate the Fuel Handling Building in the event of high radiation conditions. The Salem staff intended to review station procedures for opportunities to improve the procedures with respect to the requirements of 10 CFR 70.24 a(3).

c. Conclusions

The inspectors concluded that Salem radiation monitors and procedures adequately addressed the requirements of 10 CFR 70.24.

O8.4 Management Oversight of Quality Assurance and Nuclear Safety Review (QA/NSR)

a. Inspection Scope (71707)

The inspectors reviewed the results of an investigation of potential adverse management oversight effects on QA reports.

b. Observations and Findings

In January 1997, the Employees Concern Program received an anonymous concern that certain activities by QA/NSR managers could lead to inappropriate toning down or alteration of QA reports, and may have resulted in reprimands. The Nuclear Business Unit (NBU) managers concluded that the nature of the concern necessitated investigation by an independent source. The NBU managers appointed the Director, Nuclear Business Support as the investigation manager. The investigation manager, in turn, chose a nuclear procurement manager and an outside consultant to conduct the investigation.

The investigators reviewed a random sample of 1996 QA audits and surveillances for Salem and Hope Creek. They compared the field notes and checklists with the final reports to determine if findings had changed. The investigators also interviewed randomly selected personnel to determine the validity of the concern. In addition, the investigators reviewed performance appraisals for indications of reprimands as suggested by the concern.

The investigators found no evidence that QA staff had toned down the findings in their audits and surveillances. All interviewed members of the QA staff confirmed this conclusion. The interviewed personnel indicated that managers had not pressured them to tone down their findings with the exception of the occasional use of abrasive language in their reports. The interviewees all stated that any such changes were made with their concurrence, and if they disagreed the wording was not changed. The investigators found no indication of reprimands or other repercussions in the performance appraisals. Although the performance appraisals contained critical observation of auditors' communication skills, the investigators considered the observations constructive criticism.

c. Conclusions

The inspectors concluded that the independent investigation effectively demonstrated that QA management had not taken action that resulted in toning down QA inspector findings. The investigation also effectively demonstrated that QA managers had not taken action to reprimand or otherwise penalize QA inspectors as a result of the QA inspectors' findings.

O8.5 Commitment Management, NRC Restart Item III.14 (Open)

a. Inspection Scope

The NRC Staff identified instances where the licensee failed to meet commitments, both within the licensee's organizations and with the NRC Staff. The inspector reviewed licensee actions to insure that plant staff takes effective action to address commitments.

b. Observations and Findings

On August 21, 1996, the licensee documented the completion of a review of a sample of completed NRC commitments to ascertain whether these commitments were properly implemented. The sample included 2653 commitments consisting of 98% of commitments made between 1990 and 1995, 58% of commitments made between 1985 to 1989, 17% of the commitments associated with NRC's NUREG-0737, and 99% of the commitments associated with NRC's Generic Letter 83-28. The licensee staff obtained the commitments associated with Salem Units 1 and 2 directly from the original source documents (e.g.. Licensee Event Reports, response to Notices of Violations, and docketed correspondence). The results of the review indicated that less than 2% of the commitments (45 commitments) had not been properly implemented due to never having been implemented (7 commitments), implemented but inadvertently changed (7 commitments), or not properly implemented (31 commitments). The plant staff verified that all Salem Unit 2 restart commitments had been entered in a commitment management system.

The inspector verified that the licensee had initiated measures to resolve the 45 deficient commitments. In addition, the inspector reviewed a sample of ten additional commitments, observed the retrieval of these commitments from the licensee's data base, and confirmed that they were properly managed.

In addition to reviewing completed commitments, the licensee evaluated the commitment management process to resolve the deficiencies that had resulted in the failure to properly implement the 45 commitments noted above. The evaluation, contained in Performance Improvement Request (PIR) No. 960111309, resulted in the following short term corrective actions:

A. Plant management held a meeting with licensing personnel on January 26, 1996 to discuss the issue of commitment tracking.

B. The staff initiated a 30-day look ahead and overdue report for commitments.

C. The support staff developed commitment Performance Indicators.

D. Licensing planned to provide due dates for all commitments in correspondence to the NRC.

The inspector reviewed the implementation of the licensee's short term corrective actions and found them useful and well implemented. This is particularly true of the 30-day look ahead and overdue report, provided periodically to Salem and Hope Creek to alert responsible individuals to pending or late commitments.

In addition to the above, PIR 960111309 proposed the following long term corrective actions:

A. The licensee planned to establish expectations and standards for commitment management and communicate them to all licensing personnel. The inspector observed accomplishment of this objective in meetings held on March 27 and 29, 1996.

B. Licensing staff planned to review current Nuclear Department Administrative procedures and work standards associated with management of commitments. The inspector could not determine the schedule for completion of the revised commitment management procedures. This task is open pending inspector review and acceptance of the finalized procedures. **(IFI 50-311/97-03-02)**

C. Licensing planned to clearly communicate commitment management expectations to NBU managers. The inspector reviewed the statement of expectations associated with commitment management, forwarded to NBU management in a memo dated April 29, 1996 and found these expectations acceptable.

D. Licensing planned to evaluate other commitment tracking databases and determine if changes were necessary. The inspector noted that the licensee utilized several tracking databases to manage commitments. Although the licensee no longer used ATS to manage new commitments, it contains old commitments that still require implementation. The PIR system superseded ATS but also stopped using it to manage new commitments as of December 31, 1996. The licensee began to use the Commitment Manager database to manage all commitments as of January 1, 1997.

E. Plant staff planned to perform a self-assessment of the commitment management process. This licensee has not completed the self-assessment since it is viewed as a long term verification effort. The inspector did not consider completion of the self-assessment necessary for NRC closure of Restart Item III.14.

F. The staff planned to evaluate the process for identifying commitments. The licensee completed this effort as documented in PIR 960111309. The inspector noted that no list of long term commitments for Salem existed prior to implementation of procedure NC.NA-AP.ZZ-0030(Q), "Commitment Management", on March 15, 1992. The source documents for these commitments, however, remain available and computer searchable. Moreover, the results of the commitment verification process (an approximately 98% success rate for fulfillment of commitments) indicate that plant staff effectively managed commitments although improvements in the process remain warranted.

c. <u>Conclusions</u>

The licensee took action to improve commitment management. The licensee has developed and improved methods for commitment management (e.g.. Commitment Manager and the 30-day look ahead report), made the responsible management and personnel aware of the use of these methods and commitment management expectations, and began to improve commitment management procedures. When the licensee completes the improvements to the commitment management procedures, the NRC will close NRC Restart Item III.14.

O8.6 <u>(Closed) Violations 50-272&311/93-23 (EA 94-003-01013, 01023, 01033, 01043, 01053, 01063, 01073, & 01083) and 50-272&311/96-06-01, 96-01-01 & 96-01-02</u>: Collectively these violations documented failure to follow procedures, and fell into two categories: Tagging work practices, and verbal and procedural work control. The licensee conducted root cause analyses and identified the following causal factors: 1) less than adequate supervisory methods (insufficient management/supervisory oversight), 2) less than adequate verbal communications, and 3) less than adequate work practices (failure to follow procedures), and self checking by the individual workers. The inspector reviewed the above analysis and did not identify any additional contributing factors to those identified by the licensee.

<u>Corrective actions</u>: The licensee temporarily stopped work to communicate expectations with regard to safety and work standards to the workers. Meetings were held with contractor supervisors and craft personnel to relay the licensee expectations for safety and adherence to work standards. Operation directives were issued to re-emphasize the proper sequence of tagging work releases. Radiation technicians were reminded of the requirements for the release of materials from the work controlled area. Regarding the 1993 violation, the licensee established an on-shift middle management review group to review and assess and control of maintenance activities.

The inspector reviewed documentation confirming that the corrective actions stated above were enacted to correct the immediate concerns.

Actions to prevent recurrence: The licensee took the following actions to prevent recurrence:

1. Directions, from station management, were made annotating the expectation that supervisory/managerial personnel increase the field time spent monitoring and assessing work, providing direction, and taking appropriate corrective actions when necessary.

2. Carefully reviewed the scope of future outages to ensure management oversight is sufficient for the job tasks.

3. Decreased the number of vendors from 3 to 2 to provide better licensee oversight.

4. Provided better focus on station planning and proposed the establishment of two separate work control centers by the end of 1996.

5. Established an oversight team to; review pre-outage work progress, monitor work control progress, and review incidents of previous outages as they relate to the work standards, contractor control and work control process in general for lessons learned.

The inspector reviewed the documentation of meetings held by licensee management with all levels of the Salem organization that identified reasons for the events and emphasized management expectations for all maintenance work to be performed in the future. The inspectors noted that the concern over control of the scope of outages did not apply to the current outage due to its duration. However, the licensee plans to address the control of outage scope in the new work control process implemented after restart. Inspectors also noted that the licensee has greatly reduced the use of vendors in recent months. The plant managers implemented the "war room" concept to improve work control center effectiveness.

The oversight team was established. The inspector reviewed selected findings of the group and determined that they were focusing on the areas that would make failure to follow procedure problems less likely.

Inspectors will review the effectiveness of corrective actions for tagging deficiencies as part of NRC Restart Item III.12 prior to plant start-up.

The inspectors considered the implemented corrective actions adequate, and noted recent improvements in procedure use and adherence. This item is closed.

O8.7 (Closed) LER 50-311/96-009: fourteen day followup report regarding 12 hour shifts for operations personnel. This LER identified a conflict between the Operations staff's practice of assigning operators 12 hour work shifts versus a license requirement for 8 hour shifts (NRC Inspection Report 50-272&311/96-15 has details). Salem management requested an operating license amendment to delete the 8 hour shift restriction and the NRC has approved this request. Salem staff implemented the amendment (no. 169) on January 13, 1997. This item is closed.

O8.8 (Closed) Unresolved Item 50-272&311/96-08-06: Salem Unit 2 Operating License does not permit 12 hour operating shifts. This issue is identical to the issue in LER 50-311/96-009. This issue was licensee identified and corrected, and predates the shutdown of Salem Units 1 and 2. This licensee identified and corrected violation is being treated as a Non-Cited Violation, consistent with Section VII.B.1 of the NRC Enforcement Policy.

O8.9 (Closed) Violation E94-112-04013: PSE&G staff provided inadequate training, guidance, and procedures for operators to handle plant transients properly. On April 7, 1994, events initiated by grass intrusion into the circulating water system led to a rapid power reduction, a reactor trip and a safety injection. During the rapid power reduction, Salem operators exceeded allowable shutdown rates and the reactor temperature dropped below minimum allowable temperature. The safety injection resulted in operators filling the pressurizer to solid conditions. During the recovery from the solid pressurizer condition, neither plant procedures nor operator training was adequate in that the operators were unable to use any procedure relating to existing plant conditions.

In response to the violation, the licensee's staff made numerous procedure changes to operating and emergency procedures to provide adequate guidance for operators in handling a future event of this type. Also, the licensee developed a new procedure to address rapid load reduction for turbine load reductions of equal to or greater than 5% per minute. Salem staff trained and qualified all operating crews on the new and revised procedures. Operations personnel ran the event scenario at the Salem simulator and training personnel stopped the scenario at critical points to discuss lessons learned. The Operations manager required individuals whose performance was less than expected to complete additional training for qualification.

The inspector reviewed documentation specific to this incident and confirmed that Salem staff enhanced the procedures and that operators completed the training. The generic issue of procedure adequacy and adherence is the subject of NRC Restart Issue III.3.1. Salem staff must complete the corrective action for that item and NRC staff must evaluate the response prior to the restart of Salem Unit 2. Based on the response to this violation and the understanding that Salem management will complete NRC Restart Issue III.3.1 prior to restart, this violation is closed.

O8.10 (Closed) Violation 50-272 & 311/95-07-03: failure to follow procedures. During inspections in April and May 1995, inspectors noted five examples of activities in progress that they judged not to meet Salem procedure requirements. Although none of the examples was safety significant, the number of examples indicated a trend of procedure non compliance. PSE&G staff responded to four of the examples with appropriate corrective action and contested one example as not being a procedure violation. The inspector reviewed the response and samples of corrective action documentation. The review confirmed that Salem staff completed procedure changes and training for the four non disputed examples. The inspector reviewed the response for the disputed example and found the justification sufficient to withdraw only the fifth example of the violation. The inspector concluded that the activity, specifically, an attempt to correct a malfunctioning security door latch, did not require a procedure. Also, Salem personnel later generated a corrective action to document the replacement of worn parts. The inspector concluded that the response to this violation was satisfactory. This item is closed.

O8.11 (Closed) Violation 50-272 & 311/96-15-02: failure to follow procedures. While preparing to remove the 1C 460/230 volt bus from service, operators performed steps out of sequence. The procedure did not provide for this latitude. PSE&G staff responded to this violation with several corrective action steps as follows:

Salem management counseled the personnel involved in accordance with PSE&G site procedures.

The Operations staff revised the procedure to reflect the changed step sequence.

Salem operations management provided guidance to all operations personnel via night orders, a departmental memo, and temporary standing orders.

Salem staff issued Administrative Procedure NC.NA-AP.ZZ-0001(Q), Nuclear Procedure System, Revision 10, effective December 6, 1996 and trained operations personnel regarding use of procedures.

The inspector found that the corrective action for this specific violation was acceptable. The generic issue of procedure adequacy and adherence is the subject of NRC Restart Issue III.3.1. The NRC staff must evaluate the response to this issue prior to the restart of Salem Unit 2. Based on the response to this violation and the understanding that Salem management will resolve NRC Restart Issue III.3.1 prior to restart, this violation is closed.

O8.12 (Closed) Unresolved Item 50-272&311/93-15-04; 50-354/93-11-01, Corrective Action Program Weaknesses

In the subject inspection, the inspector identified weaknesses in the licensee's corrective action program (CAP). During a followup investigation concerning a containment fan cooler unit (CFCU) regulator, the licensee identified minor weaknesses in the incident report, engineering discrepancy control, a deficiency report, and work control processes. In this case, the inspector found the processes to be properly implemented, but noted weak coordination between these processes.

Currently, the licensee has made significant progress in improving the CAP. The implementation of a single point of entry (Action Requests) for the CAP has virtually eliminated the coordination problem between programs and processes. A recently completed inspection (50-272/96-18) noted marked performance improvement in the administration and implementation of the CAP. Based on the above, this item is closed.

O8.13 (Closed) Violation 50-272 & 311/96-08-05 : inadequate procedures. From June 30, 1996 until August 10, 1996, the NRC inspectors identified four inadequate Salem plant procedures; three were for operating plant safety related systems and one was for reactor vessel head reassembly. Salem management's response to the violation stated that plant staff revised the procedures and provided details of those changes. The response also detailed corrective steps to prevent recurrence. These corrective actions included steps specific to the procedures identified, such as communication to procedure writers and to reviewers, and more generic corrective action such as the extensive procedure review for technical adequacy as part of the Salem Restart effort.

The inspector reviewed the specific procedures identified in the violation and determined that Salem staff made the required changes. From the review of the response, the inspector also concluded that other corrective actions were satisfactory for these specific procedure inadequacies. Considering the corrective action already taken and since Salem management will resolve the generic issue of procedure adequacy prior to restart as part of NRC Restart Issue III.3.1, Adequacy and Use of Procedures, the inspector considered this violation closed.

O8.14 (Closed) Violation 50-272 & 311/96-17-01: failure to perform a safety evaluation in accordance with 10 CFR 50.59. Operators developed a temporary procedure to control activities during a total station air outage. Personnel developing the procedure incorrectly concluded that the changes to the plant detailed in the procedure did not meet the criteria of 10 CFR 50.59 to require a safety analysis. Once questioned by the inspector, Salem staff promptly completed the safety analysis. NRC Inspection Report 50-272&311/96-17 documented the fact that the inspector reviewed the safety analysis and found it acceptable. In response to the violation, Salem management communicated the event and lessons learned to operations staff and other department managers, and incorporated these lessons in the 10 CFR 50.59 training program. The inspector concluded that the corrective action for this violation was adequate. This item is closed.

II. Maintenance

M1 Conduct of Maintenance

M1.1 General Comments

a. Inspection Scope (62707)

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

- 950610179: RHR discharge valve weld repair
- 961031038: 1B EDG Elliot strainer 92 day lube
- 960927115: addition of overpressure device on CFCU return piping

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

b. Inspection Scope (61726)

The inspectors observed all or portions of the following surveillances:

- S2.OP-ST.DG-0003: 2C diesel generator surveillance test
- S2.OP-ST.DG-0004: diesel generator auxiliaries 21 fuel oil transfer system operability test
- S1.OP-ST.DG-0001: 1A diesel generator surveillance test
- S2.RE-ST.ZZ-0002: shutdown margin calculation
- S2.OP-ST.DG-0001: 2A diesel generator surveillance test
- S2.OP-ST.CVC-0001: inservice testing - 21 boric acid transfer pump
- SC.OP-ST.CAV-0001: plant systems control room ventilation
- SC.OP-ST.CAV-0001: control room emergency air conditioning system manual operation

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

M1.2 Salem Maintenance Restart Action Plan (Closed)

a. Inspection Scope

The inspector reviewed the list of corrective maintenance work orders and a sample of work orders required for restart. The inspector also reviewed corrective action documents related to maintenance issues that Salem personnel generated during the previous month to determine the nature and significance of the problems identified. In addition, the inspector monitored an ongoing Quality Assurance audit of maintenance activities and observed maintenance work in progress to gain additional insight regarding the maintenance program.

b. Observations and Findings

Salem maintenance personnel provided the inspector a list of work orders required for the restart of Unit 2 as of January 31, 1997. The list provided brief descriptions of 728 work orders and provided the status and priority of these work orders. From the review of this list, the inspector found four examples where the priorities were incorrect when compared with the criteria of procedure NC.NA-AP.ZZ-0009(Q), Work Control Process. However, personnel had appropriately prioritized the vast majority. Three of the four had a lower priority assigned than was appropriate. However, work was in progress indicating that they were in fact getting treated as priority work. Also, for those work orders on the list that were of highest priority, the status was "Work In Progress" thus indicating they too were in fact receiving priority treatment. The inspector found that this prioritizing method allowed emergent work that was urgent to be given immediate attention when necessary.

The Quality Assessment group provided copies of corrective action documents that documented problems related to maintenance. These documents, 108 in total, represented the total related to maintenance issued during December 1996. Of these, thirty-four were examples of completed work orders which did not resolve the original problem. The inspector reviewed these in more detail and determined that although this number was greater than optimum, i.e., zero, the number did not represent a significant problem in the quality of work being performed (considering that Salem maintenance was completing more than 1000 work orders per month). The inspector also noted from his review of the 108 documents that Salem staff had given adequate consideration regarding generic implications.

The inspector met with the manager of the Salem maintenance department to discuss the methods by which supervisors monitor work in the field. The inspector learned that the primary method used is a formal Self Assessment Program. The maintenance manager has set up a program that requires each supervisor to conduct and document three observations of field work per week, at a minimum. The observations are performed using an 85-point checklist as a guide. Maintenance compiles and trends the data periodically to detect weak areas of performance. Management can then direct attention to problem areas and apply corrective action. In addition, the inspector learned that the Quality Assessment group routinely performs field observations and assessments of maintenance activities and forwards this information to maintenance.

To assess the acceptability of post maintenance testing, the inspector selected ten completed work orders that, by the nature of work performed, would require testing to demonstrate acceptable work completion. The inspector found that each work order reviewed provided documentation of acceptable retesting, but noted that in most cases, the description of testing requirements, as originally provided in the work order by the planners, was vague. The inspector reviewed ten more work orders, the planning for which, had been performed within the past two months. The inspector found that for each of these more recent work orders, the description of the post maintenance testing was more specific. Most referenced a specific procedure that the technician should use to conduct a suitable test. The inspector considered these as examples of improvement in the planning of work orders with regard to describing required post maintenance testing.

The inspector performed field observations of maintenance work in progress to help assess the effectiveness of improvements made to the maintenance program. The inspector observed a calibration of a containment fan coil unit water flow controller, installation of temporary test equipment on a turbine steam bypass valve, assembly of a turbine auxiliary cooling pump, and preventive maintenance for moisture separator reheater controls. Contractors were working the first two jobs and PSE&G personnel were working the last two jobs. The inspector found that personnel were properly using procedures, were storing tools and disassembled equipment properly, and were using measuring and test equipment (M&TE) which had been properly calibrated. PSE&G personnel were knowledgeable regarding their work and when in doubt, were contacting their supervisor for assistance.

In addition to the Salem plant maintenance organization, the Maintenance Services group also performs maintenance work. Most of the work performed by this group is related to the site facilities such as buildings, traveling screens, heating boiler, and switchyard. However, the group sometimes performs work on in-plant systems such as service water (a safety related system), heater drain pumps, and the turbine. During this inspection period, the Quality Assessment organization performed an audit of Maintenance Service activities. As a result of findings from that audit regarding the M&TE calibration process and procedure non-compliance within the site services activities, the manager of Maintenance Services ordered a work stoppage. During this three day stoppage, managers and supervisors counseled technicians regarding procedure use and compliance, quality of work, safety, identification of problems and use of the corrective action program and other applicable topics. The Salem plant management decided that Maintenance Services would no longer be utilized for safety related work until the Maintenance Services management demonstrated readiness for satisfactory work control and implementation.

c. <u>Conclusions</u>

The inspector concluded from his observations that the maintenance restart action plan was effective. Management is aware of emergent work and actively participates in the assignment of priorities to safety significant work. Overall, maintenance personnel are willing to identify new problems and initiate corrective action. For the activities observed, maintenance technicians were using procedures and tools properly in the conduct of maintenance. Management actively monitors performance and status utilizing various trending tools and through the use of self assessments. Additionally, QA provides useful feedback regarding performance. The inspector considers the assessment program and the QA feedback strengths in that these feedback processes should enable management to continue the improvement process for the maintenance program. Through the review of maintenance related deficiency documentation, the inspector concluded that there are still weaknesses in the maintenance program. However, the licensee has significantly improved, and continues to improve the maintenance program. The inspector concluded that the maintenance program is ready to support restart of Salem Units 1 & 2.

M1.3 Steam Generator Replacement Project (SGRP) Inspection Procedure 50001

a. Inspection Scope

Inspections were performed to obtain an overview of current and planned work, related procedures, documentation, quality inputs and progress of the Salem Unit 1 steam generator replacement project (SGRP).

Specific areas inspected included observation of reactor coolant system (RCS) welding on no. 13 replacement steam generator (RSG), feedwater (FW) pipe welding in the fabrication shop, FW pipe welds in containment, main steam (MS) pipe machine welding mockup practice; RSG weld planning and extent of weld supervisory coverage; weld procedures and materials for RCS, MS, FW, steam generator blowdown (SGBD) piping and structural steel welding; the pre-service inspection and inservice inspection (ISI) planning to meet the requirements of 10 CFR 50.55a(g) and the ASME Code Section XI; adequacy of welds for ISI, review of Work Package 3011871086 for RSG no. 14 primary pipe welding; the as-welded root valves; the Authorized Nuclear Inspector (ANI) involvement in SGRP activities as documented in work packages; preparation and procedure controls for Radiography, the quality and acceptability of interim and final Radiographs on the RCS welds of RSGs 11, 12 & 14; original steam generator (OSG) and RSG moving, handling, rigging and lifting; observation of movement of the third OSG to and onto the barge for transport offsite; the prejob briefing for and upending of RSG 11 in containment; foreign material exclusion (FME) control; the basis for why the new insulation for RSGs and piping is acceptable; the post RSG installation restoration process including controls and documentation; the Polar crane remote control; Polar Crane track clamps/seismic restraint interferences; and fire control.

The site inspection included observations of conditions and work in and outside the containment structure.

b. Observations and Findings

By March 12, 1997, the 4 original steam generators (OSGs) had been shipped from the site by barge for burial. The 4 replacement steam generators (RSGs) were in place in the Unit 1 containment building with welding of the steam generator nozzles to the reactor coolant piping complete and accepted by radiographic examination. Fitup and welding of the feedwater and main steam piping was in progress. Restoration of other items removed as a part of the SGRP, including the steam generator upper restraints and structural steel, was continuing.

The inspection found that work activities were generally well planned and properly documented. The machining of the steam generator RCS nozzles and RCS piping elbow ends to dimensions developed, using computer-based measuring techniques, resulted in RCS weld joint fitups that met very close tolerances. The work packages were being tracked and closed out at a rate commensurate with work completion. Surveillances of project conditions and specific work activities were done by project Quality Assurance. In project areas where problems were identified, work was delayed or stopped until an acceptable course of action was established. Examples of problems include the interference of the polar crane seismic lug with one of the track hold down lugs during positioning of the fourth RSG, resolution of upper RSG support details, the selection of a volumetric ISI inspection method for the RCS elbow-to-head nozzle welds due to the difficulty of performing an adequate UT examination of the cast stainless material, and the acceptability of the weld surface contour for ISI ultrasonic inspection of the FW pipe transition pieces to RSG FW nozzles.

The engineering work packages, EWP-1EA-1243-01 and EWP-1EA-1243-02 and PCI Report on Transport Analysis of Nukon Insulation (PCI ltr 90-1079-09), provide information on the adequacy of the replacement insulation for the RSGs and piping. These are inputs for the 10 CFR 50.59 evaluation to determine that the thermal insulation used on the RSGs and that replaced on piping would not interfere with the flow of water to the containment sump during assumed accident scenarios. The engineering review of the replacement insulation was noted to be a detailed process that, although not final, had not identified any unexpected difficulties in the performance of the RSG and piping insulation.

c. Conclusions

The inspections found a generally high level of project performance in the areas inspected and identified no safety significant project deficiencies. For example, controlled work packages were in use and project communication was maintained by prejob briefings and daily plan of the day meetings. Quality assurance, mainly by surveillances, was continuing. Welder qualification testing, control of weld materials and component welds were of high quality.

M1.4 Routine Maintenance Observations

a. Inspection Scope (62707)

The inspector observed routine corrective maintenance activities including the repair of a jacket cooling water leak and restoration of the 1C emergency diesel generator (EDG), and the replacement of the 11 service water (SW) pump.

b. Observations and Findings

- 1C Emergency Diesel Generator

The operators identified a leak from 1C EDG jacket cooling water system following a post maintenance test run. Maintenance technicians pressurized the EDG jacket cooling system and determined that the leak was through the 7L cylinder. The maintenance technicians removed the cylinder head and installed blind flanges to permit additional EDG jacket water pressure testing to ensure that there were no other system leaks. The inspector observed the pre-evolution brief, and a portion of the EDG jacket cooling water pressure test and noted that the brief was thorough, and that the testing was performed in accordance with procedure SC.MD-PT.DG-0001, "Diesel Engine Jacket Water Pressure Test." No other leaks were identified, and the maintenance technicians replaced the 7L cylinder head. A maintenance supervisor indicated that the failed cylinder head would be shipped to the vendor for a failure analysis.

During the subsequent post-maintenance testing, operators noticed variations in the EDG output frequency. The licensee contacted the EDG vendor for technical assistance and developed a troubleshooting plan for correcting the frequency problem. The inspector reviewed the troubleshooting plan and determined that it was logical. During troubleshooting, the licensee identified that the frequency problem was caused by the electronic governor assembly. Maintenance technicians replaced the assembly and successfully retested the EDG on March 6. The inspector observed a portion of the testing and noted that it appeared to be well controlled and in accordance with the procedure.

The inspector reviewed the EDG test data taken during the post-maintenance surveillance testing in accordance with S1.OP-ST.DG-0003. The inspector verified that the EDG starting response characteristics (frequency, engine speed, and voltage) were acceptable. The inspector concluded that procedure adherence was excellent throughout this maintenance activity, and that the licensee implemented a sound plan for restoring the EDG following the cylinder water leak.

- 11 Service Water Pump

The 11 service water (SW) pump was replaced in accordance with maintenance procedure, SC.MD-EU.SW-000, "Johnston Service Water Pump Removal And Installation." During the pump removal and installation activities the inspector observed good procedure adherence, supervisory oversight, and foreign material exclusion (FME) controls.

During the post-maintenance testing and packing adjustment, the pump packing assembly became overheated. The operator secured the pump, however, the heat generation damaged the pump shaft necessitating an additional replacement of the pump. Condition report (CR) 970228053 was generated to investigate the root cause(s) for the packing problem. The investigation identified several potential root causes for the packing problem including inadequate installation and adjustment instructions.

The packing was a new style packing and several inconsistencies were identified in the vendor's guidance regarding adjustment and installation of the packing. The inspector interviewed a design engineer and learned that the licensee intended to replace the pump and install the original style packing. The inspector concluded that this occurrence demonstrated poor engineering design control, but noted that this condition was of minimal significance since the SW system was not required to be operable for Unit 1.

c. Conclusions

Maintenance technicians demonstrated good procedure adherence during repair of the 1C EDG jacket cooling leak, and during replacement of the 11 SW pump. Troubleshooting of the 1C EDG frequency variations was logical. Weak engineering controls were established prior to changing the type of packing in the 11 SW pump.

M2 Maintenance and Material Condition of Facilities and Equipment

M2.1 Packing Leakage and Control of Deficiency Tags

a. Inspection Scope (71707)

The inspector routinely toured the facility to assess safety-related component leakage, lubrication, and general condition.

b. Observations and Findings

The inspector identified that numerous safety-related valves exhibited minor packing leakage shortly after maintenance personnel had retorqued or repacked the glands (22RH18, 2RH71, 2CV54, 21SS116, 21SS46). Maintenance supervision initiated a CR (970218215) to investigate the apparent cause of persistent packing leakage.

The inspector identified that a planner inappropriately closed a packing adjustment work request for 22RH18 (22 residual heat removal heat exchanger outlet throttle valve) and failed to remove the equipment malfunction identification system (EMIS) tag. A maintenance supervisor replaced the inactive EMIS tag and initiated a work order to repair the packing leak. In addition, maintenance staff failed to remove several other EMIS tags that listed previously corrected or rejected deficiencies (22CC pump, 21CC3, 21CC16, 2A EDG jacket water cooler).

The inspector observed inactive EMIS tags in place identifying inadequate 2B and 2C diesel day tank level indication. On July 29, 1996, engineering closed out CR 960516192 for 2C day tank and on January 21, 1997, the maintenance work-it-now (WIN) team rejected CM 970116120 on 2B day tank without resolving operator concerns. The lack of resolution, combined with the inactive EMIS tags, caused operators to unnecessarily abort a diesel fuel oil transfer pump surveillance on February 16, 1997, and estimate daily diesel day tank log readings. Following inspector identification, the operating shift initiated CR 970218221 to address diesel day tank level indication.

During the inspection, plant staff and managers separately identified several cases of problems resulting from ineffective control of EMIS tags. As a result, the management team planned to inspect the plant to identify and remove inactive

EMIS tags. In addition, they intended to develop methods to improve EMIS tag controls.

c. Conclusions

The minor material condition deficiencies did not result in any safety consequence, however, maintenance did not demonstrate effective packing leakage repair or adequate EMIS tag control. Maintenance and engineering did not adequately support operations in resolving diesel day tank level indication inadequacies. Plant managers independently identified problems with EMIS tag controls. The licensee planned to systematically remove inactive tags and develop methods to improve control of the tags.

M3 Maintenance Procedures and Documentation

M3.1 Component Cooling Pump Repair (62707)

The inspector observed maintenance technicians repair no. 23 component cooling pump mechanical seal. Technicians demonstrated good maintenance practices involving foreign material exclusion, safety-related part storage, tagging, and work area cleanliness. Technicians appropriately implemented procedure revisions in accordance with station policy. Technicians properly documented work and maintained the procedure up to date. The supervisor provided good oversight and direction at the job site. The inspector concluded that technicians properly controlled and conducted safety-related maintenance on the no. 23 component cooling water pump.

M8 Miscellaneous Maintenance Issues

M8.1 NRC Restart Item III.17, Work Control and Planning Program; Work Control Process Improvement Restart Action Plan (Closed)

a. Inspection Scope

Salem staff determined that emergent work, work package content, and process inefficiencies limited work control effectiveness. The inspectors reviewed Salem staff's resolution of these deficiencies.

b. Observations and Findings

The Work Control staff, comprising planners and schedulers, developed problem statements to address major areas for improvement. They completed the actions associated with the problem statements and on January 8, 1997, the Management Review Committee (MRC) affirmed the work control process ready for restart. Each problem statement is followed by the results of inspection for the area.

<u>Problem Statement 1</u>: The existing work control process requires better definition, structure, and discipline.

To resolve this problem, the Work Control Manager established new mechanisms such as a WIN team to screen and validate corrective maintenance tasks; a Minor Maintenance program; a process for controlling limiting condition for operation (LCO) maintenance; a checklist to establish consistency in work package quality; an automated, on-line process for resolving work-in-progress problems; and a work package completion, retest, and closure process. Salem management incorporated these innovations in a Work Control Program Manual, and trained the planning and scheduling staff on the new processes contained in the Manual. By a sample of training records, the inspector confirmed planning management trained their staff on the Manual. The inspector also discussed the process improvements with work control members to determine whether the measures were effective and, based on the responses, concluded the initiatives adequately resolved the problem statement. This problem statement is closed.

<u>Problem Statement 2</u>: Low staffing levels and process inefficiencies have contributed to an accumulation of functional area backlogs which contribute to material and performance deficiencies. The existing backlogs should be reduced to levels which permit the application of available resources to the resolution of real time conditions.

Inspectors reviewed the status and content of the maintenance backlog during the inspection for NRC Restart Item III.4.2, Work Order Backlog Reduction Plan. From that inspection, the inspectors determined that Salem management was managing the backlog and the inspectors no longer consider this issue a restraint to the restart of Salem Unit 2. The inspectors documented the details of that inspection in NRC Inspection Report 50-272,311/96-18. This problem statement is closed.

<u>Problem Statement 3</u>: Organizational functions interfacing with and supporting the Work Control Process need improvement.

To assess the effectiveness of corrective actions taken by Salem management to resolve this problem, inspectors attended daily work coordination meetings and performed field observations of work in progress. Each day, representatives of the principal organizations, (maintenance, operations, chemistry, radiation protection, fire protection, and engineering), meet for the sole purpose of discussing and coordinating the work items which maintenance plans to work that day. The inspectors determined that the representatives were knowledgeable and they conducted the meetings professionally. In several cases observed, operators postponed or rescheduled work due to conflicts the staff identified during these meetings. In other cases, operations pointed out high priority items needing maintenance to support operation of plant systems. The inspector found that these meetings improved coordination of work. From the field observations, the inspectors determined that technicians were working priority tasks as required, and were receiving support as needed from planning, supervision, and engineering when problems arose. In one example, technicians could not install a pump seal in accordance with the procedure. The technicians stopped work, and held discussions with engineering to resolve the problem. Later, the staff revised the procedure to reflect the field requirements.

Inspectors monitored a Quality Assessment maintenance audit that was ongoing during the inspection period. As part of that audit, Quality Assessment personnel interviewed maintenance technicians to help assess the effectiveness of work control. The inspectors found that technicians recognized a need for more improvement in work control but all stated that the work control staff made significant improvements to the process during the past six months. Supervisors frequently visited the job site, and engineering and planners were readily available to help resolve problems.

This problem statement is closed.

Problem Statement 4: The Managed Maintenance Information System (MMIS) needs to be enhanced to support a comprehensive work control process.

The Planning staff implemented software changes that made the work order system more efficient and increased task accountability. For example, now work initiators can assign minor maintenance directly to the WIN team, and senior reactor operators can electronically approve work orders. Also, work orders now have a required sign-off for job supervisors that signifies they have walked down a task and it is ready for technicians to work. The inspector confirmed that work control management trained the staff on the modifications and, based on discussions with the staff, concluded the enhancements had improved and streamlined the work control process. This problem statement is closed.

Problem Statement 5: The performance indicators used to monitor and track work control process functions do not provide sufficient visibility of process weaknesses.

During this inspection period and in past inspection periods, inspectors reviewed and utilized Salem performance indicators. The inspectors noted that indicators are in place to monitor backlog status, job rework rate, work holds due to engineering and parts requirements, and other important indicators that enable Salem management to identify and correct work process weaknesses. This problem statement is closed.

Problem Statement 6: A systematic, structured Self-Assessment is needed as part of the Work Management Program process control function.

Procedure SC.SA-AP.ZZ-0034(Q), *Self Assessment Program*, governs implementation of self assessments. The adequacy of AP-34 is the subject of NRC Restart Issue III.21, Self Assessment Capability, and therefore was not part of inspecting this problem statement.

The inspector verified that the work control and planning group performed a self assessment in accordance with AP-34. The inspector read the assessment and reviewed QA staff's comments regarding the assessment. The inspector noted the QA staff made several insightful comments. First, the assessors did not discuss work control performance with key users of the work control and planning program. For example, the assessors did not interview personnel from radiation protection, the work control center, chemistry, or tagging. Second, the assessment team was made of exclusively planning and work control personnel; no personnel from outside the organization were members. The QA team provided these comments to the assessment team leader for resolution. Subsequently, the self assessment leader augmented his team with representatives from the work control center and maintenance, then conducted additional interviews with personnel from radiation protection, the work control center, and maintenance. The inspector reviewed the followup assessment and noted it identified additional areas for improvement. The inspector concluded that the work control staff adequately implemented the assessment process. This problem statement is closed.

Problem Statement 7: Ensure functions to support on-line processes are in place prior to startup.

The inspector noted work control management has implemented the functions that support the work management process. For example, the inspector determined the staff has issued the WIN Team Desk Guide, the Radiation Protection Desk Guide, identified work week managers, named work group coordinators, and trained the staff on the Guides and new functions. This problem statement is closed.

c. Conclusions

Salem management has improved, and continues to improve, work control effectiveness. The licensee improved the process, trained personnel, and increased staffing levels in the planning and scheduling group. The Salem staff addressed the work order backlog and are using performance indicators to monitor progress. While personnel could still improve performance, work control staff's response to their self assessment indicated to the inspector that management would ensure the organization continued to address deficiencies. The inspector concluded the work control program is ready to support Salem restart.

M8.2 (Closed) Unresolved Item 50-272 & 311/95-17-03: evaluation of corrective action regarding Salem Unit 1 steam generator tube inspection weaknesses. Westinghouse personnel performed the eddy current testing and data analysis as a contractor to PSE&G during the 1993 and 1995 outages. The NRC inspection determined that Westinghouse engineers misinterpreted defects that should have required plugging of eight tubes. Consequently, Salem technicians did not plug these tubes. Also, Westinghouse staff used probes that were not qualified for the application, and data from different style probes did not correlate. Salem management was very prompt and aggressive in addressing these issues. The licensee issued a stop work order, arranged for an independent organization to perform data reanalysis, and developed site specific analysis guidelines for eddy current testing probes. Subsequently, management corrected eddy current testing weaknesses, contracted with a new vendor for steam generator inspections, and replaced Unit 1 steam generators. The inspector also verified that, as part of the maintenance restart plan, Salem management implemented significant corrective action during the past months to improve control of contractors. Based on the information above, the inspector considers this unresolved item closed.

M8.3 (Closed) Violation 50-272&311/94-14-02: failure to provide adequate training to maintenance personnel. In July 1994, maintenance personnel attempted to implement preventive maintenance on the turbine driven auxiliary feedpump. The objective was to change the oil in the gear box. During the process, technicians inadvertently added oil to the governor oil reservoir and also disturbed the turbine overspeed trip device. The turbine subsequently tripped on overspeed during post maintenance testing.

The inspector completed an inspection on the effectiveness of the maintenance restart plan and documented the results in Section M1.2. Maintenance management addressed the causes of this incident, i.e. poor training, lack of a questioning attitude, and poor pre-job briefing, in generic maintenance program improvements described in the restart plan. Salem staff also responded to the violation with detailed corrective actions that addressed this specific event. Salem staff counseled the personnel involved, enhanced training modules, and stressed to first line supervisors the importance of good pre-job briefings. The inspector concluded the corrective measures adequately addressed this issue. This item is closed.

III. Engineering

E1 Conduct of Engineering

E1.1 Generic Letter 89-10 Motor-Operated Valve Program Review (T/I 2515/109) (Closed), NRC Restart Issue III.a.23, Adequacy of Motor Operated Valve Program (Closed)

Introduction and Purpose

On June 28, 1989, the NRC issued Generic Letter (GL) 89-10, "Safety-Related Motor-Operated Valve Testing and Surveillance," requested licensees to establish a program to ensure that switch settings for safety-related motor-operated valves (MOVs) were selected, set, and maintained properly. Seven supplements to the GL have been issued to provide additional guidance and clarification. NRC inspections of licensee actions implementing the provisions of the GL and its supplements have been conducted based on the guidance provided in NRC Temporary Instruction 2515/109, "Inspection Requirements for Generic Letter 89-10," which is divided into three parts.

The NRC conducted the Part 1 inspection at Salem in May 1992 as documented in NRC Inspection Report (IR) 92-80. IR 93-24 reviewed the status of the open items developed during the Part 1 (program) inspection. A Part 2 (implementation) inspection, conducted in November and December 1993, was documented in NRC IR 93-26. An initial Part 3 (closure) inspection was documented in IR 96-11.

A public meeting was held on November 12, 1996, to discuss PSE&G plans to complete the Salem Unit 2 MOV program, as well as to discuss the unresolved issue of MOV program status in the context of 10 CFR 50.9(b). The slides presented by PSE&G during the November 12th meeting are attached to this inspection report. The purpose of this more recent inspection was to review PSE&G's corrective actions for the findings from IR 96-11 and to again address closure of the GL 89-10 program at Salem Unit 2.

E1.2 Summary Status of Generic Letter 89-10 MOVs

a. Inspection Scope

In GL 89-10, the NRC requested notification within 30 days after the MOV design-basis reviews, analyses, verifications, tests, and inspections have been completed. In a letter dated March 20, 1995, PSE&G notified the NRC that the committed programmatic actions taken to address Items a through h of GL 89-10 had been completed at Salem Unit 2. The inspectors reviewed PSE&G's S-C-VAR-NEE-1117, "Generic Letter 89-10 Closure Summary for the Motor Operated Valve Program as Implemented at Salem Unit 2," Rev. 0, and documents associated with all MOVs in the GL 89-10 program. Using these documents, a valve sample was selected that included examples of all methods used to demonstrate design-basis capability.

b. Observations and Findings

PSE&G used several methods to demonstrate MOV design-basis capability which included verification by:

- Valve-specific dynamic test at, or near, design-basis conditions,
- Valve-specific test, linearly extrapolated to design-basis conditions,
- In-plant information obtained from dynamic tests on similar MOVs. and
- Electric Power Research Institute's (EPRI) Performance Prediction Model (PPM) applied to MOVs that were not practicable to test.

PSE&G had dynamically tested 46 of the 94 MOVs in the GL 89-10 population at Salem 2. PSE&G provided information for the 94 MOVs which were grouped into 16 MOV families. The inspectors reviewed special test packages and engineering evaluations for the following MOVs:

22SJ40	(Family 2)	Safety Injection Pump to Hot Leg Isolation Valve
2RH1	(Family 6)	Reactor Coolant System (RCS) Hot Leg to Residual Heat Removal (RHR) Suction Header Valve
2CC136	(Family 5)	Reactor Coolant Pump (RCP) Motor Bearing Cooling Water Outlet Valve
22SJ33	(Family 1)	Safety Injection Pump Suction Valve
21SJ113	(Family 3)	Containment Spray Pump Discharge Isolation Valve

E1.3 MOV Sizing and Switch Settings

a. Inspection Scope

The inspectors reviewed valve packages that established the thrust requirements for MOVs in their GL 89-10 program. These documents included thrust calculations and test evaluation packages associated with the selected MOVs. PSE&G's methods for determining minimum thrust requirements were documented in Motor Operated Valve Program - Appendix 6 "MOV Mechanical Capability Review," Rev. 4, dated June 7, 1994, and EE: A.-O-ZZ-MEE-0609, "MOV Program Position Papers," Rev. 5, dated April 9, 1996. The purpose of this review was to assess the licensee's justifications for assumptions used in MOV thrust calculations which form the basis for determining the design-basis requirements.

b. Observations and Findings

PSE&G's thrust calculations typically utilized the standard industry equations. Mean seat diameter was used to calculate valve seat area. Valve factors were based on the in-plant test results or other industry sources as specified by the licensee's grouping methodology. A stem friction coefficient of 0.20 was used for determination of actuator output thrust capability. The licensee applied margin to account for diagnostic equipment uncertainty, torque switch repeatability, load sensitive behavior, and potential valve degradations.

Valve Factor and Grouping

PSE&G classified Salem MOVs into valve families based on manufacturer, type, and ANSI pressure class rating. Some families contained a range of valve sizes. PSE&G attempted to use in-plant data for justification of valve factors for non-dynamically tested MOVs. However, PSE&G did not have sufficient in-plant test results to adequately cover all valve groups. During the program review, the inspectors noted that the licensee initially did not provide adequate justification for MOVs in Families 6 and 9. However, further discussion resolved the inspector's comments as follows:

- Family 6: 14" Copes Vulcan 2500psi Parallel Double Disk Gate Valves

This family consisted of the RCS hot leg-to-RHR suction header valves (2RH1 and 2RH2). PSE&G was unable to obtain in-plant or applicable industry data for these valves. To address this issue, the licensee reviewed the "separate effects" friction test program that was conducted by EPRI as part of the Performance Prediction Program (PPP). A friction coefficient of 0.55 was selected based on an expected operational water temperature of 200-300° F. This justification was not considered adequate for program closure because the EPRI separate effects testing was only one of many parts of what the NRC reviewed regarding the PPP.

After discussion with the inspectors, PSE&G revised its valve factor for these valves to 0.61 which was based on the maximum value experienced during dynamic in-situ testing at Salem Unit 2. Also, PSE&G intended to modify valve 2RH1 prior to restart to make it comparable to valve 2RH2, thereby improving its actuator capability. While both valves were shown to have adequate design basis capability, the inspectors noted that the valve factor basis for these valves was still weak and could be better supported in the long term. Based on PSE&G's intent to pursue an improved valve factor basis for these valves as part of their periodic verification program and modifications to be performed prior to restart, the inspectors concluded that these valves were acceptable for GL 89-10 closure. An inspector followup item will track implementation of issue 2RH1 and 2. **(IFI 50-311/97-03-03)**

- Family 9: 3" & 4" Velan Flex Wedge Gate Valves

The inspector's comments for this family focused on the power operated relief valve (PORV) block valves (2PR6 and 2PR7) and the RCP thermal barrier isolation valves (2CC131 and 2CC190). PSE&G modified the PORV block valves to operate them based on limit switch control. The modification provided an "available" valve factor (i.e., functional upper limit) of 0.61 to close the valve. Given this apparent capability, use of a 0.2 stem friction coefficient, and the application of actuator pullout efficiencies, the inspectors considered the current settings of the PORV block valves to be adequate. However, the inspectors requested PSE&G to confirm the technical adequacy of the basis for valve factor, and to address any potential non-predictability for the PORV block valves as part of Salem Unit 2's periodic verification program. PSE&G agreed and stated that they will review the possibility of applying the EPRI PPM methodology for these valves. An inspector followup item will track implementation of this issue for valves 2PR6 and 7. **(IFI 50-311/97-03-04)**

For the RCP thermal barrier isolation valves (2CC131 and 2CC190), the licensee used EPRI PPM test data in a unique manner to determine a bounding valve factor of 0.64. The unique treatment of the EPRI PPM test data was described in a vendor (MPR Associates) calculation that was included as Attachment 24 to PSE&G's Engineering Evaluation S-C-VAR-

NEE-1117. The statistical approach utilized in this calculation was not endorsed in the NRC's safety evaluation of the EPRI PPM, and was considered to be unacceptable for GL 89-10 closure.

PSE&G revised the valve factor to 0.54 which was based on the highest value obtained from testing similar Salem Unit 2 valves. Both valves were still shown to have positive thrust margins, with 2CC131 the least at 8%. While the inspectors considered this acceptable for GL 89-10 closure, PSE&G was requested to take measures at the first opportunity to improve the actuator capability for these MOVs. The inspectors also requested PSE&G to confirm the technical basis of the valve factor, and to address any potential non-predictability for these valves as part of periodic verification. PSE&G agreed and stated that they will review the possibility of applying the EPRI PPM methodology for these valves. An inspector followup item will track implementation of this issue for valves 2CC131 and 190. **(IFI 50-311/97-03-05)**

Load Sensitive Behavior

Attachment 19 of the Unit 2 Closure Summary documented a statistical analysis of 75 data points, an average load sensitive behavior of 3.7% and a standard deviation of 9.6%. Based on this analysis, the licensee's error analysis added 4% directly as a bias margin and 21% as a random value that was included with other uncertainties using the square root sum of the squares method. The inspectors found the licensee's analysis and load sensitive behavior margin to be acceptable for non-dynamically tested MOVs at Salem Unit 2.

Stem Friction Coefficient

PSE&G recently completed a comprehensive stem friction coefficient review of the results from in-plant testing. Based on this study, PSE&G increased Unit 2's assumed stem friction coefficient value from 0.15 to 0.20. The inspectors found the licensee's stem friction coefficient justification to be acceptable for Salem Unit 2.

Degradation Margin

NRC Inspection Report 50-311/96-11 noted that the licensee's margin to address potential future valve degradations may not exist if other uncertainties were large enough to consume the fixed 30% margin that was used to account for these uncertainties. Recently PSE&G revised their setup methods to include a 5% bias margin to account for degradations as a part of their standard error analysis. Results from Salem's periodic verification program will be used to revise this 5% margin if necessary. The inspectors found this approach to be acceptable.

Linear Extrapolation

The inspectors reviewed Section 4.4.5 of the Unit 2 Closure Summary which contained PSE&G's justification for use of linear extrapolation to account for differences between dynamic test conditions and design-basis conditions. PSE&G's justification was based on results from EPRI's PPM. The inspectors did not identify any concerns with the licensee's general method for extrapolating test results. However, the inspectors requested that PSE&G review the NRC's Safety Evaluation (SE) by the Office of Nuclear Reactor Regulation of Electric Power Research Institute Topical Report TR-103237, "EPRI Motor-Operated Valve Performance Prediction Program," dated March 15, 1996, and EPRI's latest recommendations related to use of linear extrapolation. The licensee's review was requested to ensure that adequate disk loading was obtained during testing at Salem Unit 2, and in order to improve the reliability of wide extrapolations.

c. Conclusions

The justifications for key program assumptions were complete and the applied valve factors for Salem Unit 2 MOVs were adequate for GL 89-10 closure. These conclusions were based on the understanding that PSE&G would pursue actions for certain MOVs in Families 6 and 9 in conjunction with the periodic verification program for Salem Unit 2 MOVs. These additional evaluations were agreed to be formalized in a revision of the Salem Unit 2 GL 89-10 closure summary document S-C-VAR-NEE-1117.

The inspectors noted that progress was achieved since the previous NRC inspection as reported in NRC Inspection Report 50-311/96-11. The inspectors also noted that NC.DE-PS.ZZ-0033(Q), "Motor Operated Valve Programmatic Standard and Appendices," was not consistent with PSE&G's current margin and error analysis assumptions, as presented in the Salem 2 GL 89-10 Closure Summary document.

E1.4 Design-Basis Capability

a. Inspection Scope

The inspectors reviewed dynamic test evaluation packages that were performed in accordance with Appendix 14 of the Motor Operated Valve Programmatic Standard and associated test reports for the selected MOVs. The purpose of this review was to assess PSE&G's efforts to establish design-basis capability for all MOVs in Salem Unit 2's GL 89-10 program.

b. Observations and Findings

Reactor Coolant System Hot Leg-to-Residual Heat Removal Suction Header MOVs

During the initial review of Salem Unit 2's Closure Summary document, the inspectors noted that the RCS Hot Leg to RHR Suction Header Valve (2RH1 - Family 6) had an identified 1% thrust margin. As noted in Section E1.3 of this report, the licensee had applied a 0.55 valve factor which was inadequately justified. Further, the inspectors noted that the margin calculation for 2RH1 did not include any margin for load sensitive behavior (because of limit switch control), or valve degradation. However, as discussed in Section E1.3, after further discussion with the inspectors, the licensee changed the approach to demonstrating design basis capability by adopting a higher valve factor and agreeing to perform modifications prior to restart of Salem Unit 2. The inspectors concluded that this was acceptable for these valves for GL 89-10 closure.

Thrust Margin Improvement

The inspectors noted that several Salem Unit 2 MOVs were scheduled for margin improvements. However, the following MOVs had adequate basis for the applied thrust requirements, but had low thrust margins and were identified by the inspectors to ensure that they are included in PSE&G's margin improvement plans:

2CC136	22CC16	2SJ4
21BF13	22BF13	2SJ5

The licensee was requested to review this list and to include these MOVs as part of their margin improvement program. PSE&G personnel agreed to conduct this review. Closure of these MOVs under the generic letter program was considered contingent upon the licensee's agreement to improve the margin of these MOVs as part of Salem Unit 2's long term MOV program (IFI 50-311/97-03-06).

Pratt Butterfly Valves

Family 16 consisted of 8" and 24" Pratt butterfly valves. The licensee used the EPRI PPM butterfly model to develop the torque requirements for these valves. Further, the licensee has initiated Minor Modification package No. S-96-019 to change the spring packs which will increase the output capability for the four 24" valves. However, these modifications were not complete at the time of the inspection. PSE&G has scheduled these modifications to be completed prior to restart of Salem Unit 2. The inspectors concluded that the methodology for setting the torque switches for these valves was acceptable for GL 89-10 closure.

MOV Thermal Overloads

During a recent inspection of the component cooling system as reported in NRC Inspection Report 50-311/96-81, the inspectors found that design change DCP 2EC-3249 installed thermal overload (TOL) relay heaters on MOV circuits that were different than the design basis calculation ES-18.006. The inspectors requested confirmation that the correct heater sizes were used in the MOV program, NC.DE-PS.ZZ-0033 (Q). Appendix 5, Electrical Capability Review, of this MOV program document presented the methodology establishing the degraded voltage factor for the MOV program analyses. The MOV group maintains a separate file for each valve in which the TOL heater resistance is used in part of the analysis to determine the voltage at the valve motor.

In response to the inspector's concern, PSE&G compared the as-installed TOL heaters with the TOL heaters used in the analyses. PSE&G identified spray additive isolation valve 2CS14 and RCP motor and bearing cooling water valve 2CC118 with heaters that were a smaller size than used in the analyses and, because of their increased resistance, would result in a lower degraded voltage factor than that used in the MOV program analysis of record. PSE&G reran the analyses for these two valves and reviewed the results with the inspectors. The results of the reviews indicated that the degraded voltage factors would decrease by 2% but the valves were still capable of developing sufficient torque under the new degraded voltage conditions.

PSE&G prepared AR 970116087 to document this discrepancy.

c. Conclusions

The inspectors concluded that PSE&G had adequately demonstrated design basis capability for Salem Unit 2 MOVs such that the NRC review of GL 89-10 could be closed. This inspection also closes NRC Restart Issue III.a.23, Adequacy of Motor Operated Valve Program. This conclusion was based on the understanding that PSE&G would pursue actions for certain MOVs in Families 6 and 9 in conjunction with the periodic verification program for Salem Unit 2 MOVs.

E1.5 Pressure Locking and Thermal Binding

a. Inspection Scope

The inspectors reviewed the evaluation of gate valves susceptible to pressure locking (PL) and/or thermal binding (TB) which the licensee had completed in response to GL 95-07, "Pressure Locking and Thermal Binding of Safety-Related Power-Operated Gate Valves." As indicated in the licensee's response to GL 95-07 dated February 13, 1996, PSE&G identified 8 valves (21CS2, 22CS2, 2SJ12, 2SJ13, 2SJ1, 2SJ2, 21SJ113, and 22SJ113) that were considered to be susceptible to PL for Salem Unit 2. In addition, PSE&G identified 4 valves (21CC16, 22CC16, 2PR6, and 2PR7) that were considered to be susceptible to thermal binding for Salem Unit 2.

b. Observations and Findings

PSE&G indicated that holes were drilled in 6 of the 8 valves that were susceptible to PL. In addition, PSE&G modified the procedures for the 21CS2 and 22CS2 valves to include valve cycling after surveillance testing. The inspectors concluded that the licensee's modifications were adequate to address the susceptibility of PL for the modified valves.

PSE&G also indicated that TB concerns were addressed for the PORV block valves, PR6 and PR7, by modifying the MOV control circuit from torque control to limit control. It was noted that the unwedging force was significantly decreased following the modification. The MOV static test trace from the diagnostic equipment (i.e., VOTES) indicated approximately 2673 lbs. of unwedging force for the PR6 valve. A calibration error of 40% was added to the unwedging force; therefore, the unwedging force for PR6 was recalculated to be about 3842 lbs. The inspectors were not able to verify the unwedging force for PR7 due to diagnostic sensor problems.

By letter dated July 1, 1996, the NRC staff asked PSE&G to supply additional information concerning their submittal in response to GL 95-07. By letters dated August 7 and 30, 1996, PSE&G provided a response to the staff's request for additional information. PSE&G indicated that the RH-26 valves were not within the population of valves considered to have a safety-related or important to safety function to open; therefore, the licensee did not evaluate the susceptibility to PL for the RH-26 valves. The inspectors noted that PSE&G's position concerning 2RH26 remained the same during this inspection as it was not included in the scope of the GL 89-10 program (see Section E1.2). Regarding the PORV block valves PR6 and PR7, PSE&G indicated that an evaluation of these valves under conditions associated with a steam generator tube rupture had been completed. The licensee concluded that there was a negligible effect on the required unwedging thrust for the PR6 and PR7 as a result of a steam generator tube rupture. Accordingly, the licensee concluded that there was no increase in the required thrust associated with the PL scenario. PSE&G indicated that valve specific evaluations were performed with respect to valve and system function; however, no specific training had been conducted regarding modifications.

The inspectors noted that PSE&G utilized the services of MPR Associates, who developed an analytical method to determine a maximum inertial thrust limit below which TB should not be a concern for the 21CC16, 22CC16, 2PR6, and 2PR7 valves. In reviewing the MPR analysis, the inspectors determined that the test data that was used for this analysis did not completely validate the model to determine the susceptibility to TB for the PR6 and PR7 valves. In addition, the inspectors found that MPR's key assumption in their calculations for deriving a PL/TB model may not adequately consider transient or steady state temperature gradients in the valve body or valve disk.

The MPR analysis included an analytical method that was utilized to demonstrate that the actuators on the PORV block valves, PR6 and PR7, could develop adequate thrust to overcome pressure locking. PL thrust requirements for these valves were calculated by a method of the MPR analysis. The inspectors independently calculated the thrust required to overcome PL and determine the actuator capability for the PR6 and PR7 valves and concluded that the actuators were able to develop the thrust required to overcome PL.

The inspectors noted that a response to one item of the RAI was still required by the licensee and had not been submitted. The licensee indicated that a response to this item would be submitted to the NRC in the near future.

c. Conclusions

The inspectors did not find any immediate safety or operability concerns regarding any Salem Unit 2 MOVs. PSE&G's modifications and other actions to address PL and TB in the short term were acceptable. However, in the long term for satisfying GL 95-07, PSE&G was requested and agreed to determine and confirm at the earliest opportunity that the unwedging force for 2PR7 is comparable to 2PR6. Also, PSE&G was requested and agreed to further discuss and resolve with the NRC questions regarding assumptions and test validation of the MPR Associates PL and TB analytical model.

E1.6 MOV Failures, Corrective Actions, and Performance Trending

a. Inspection Scope

The inspectors reviewed two recent MOV failures concerning component cooling (CC) water valve 22CC3 and service water valve 22SW17. The inspectors evaluated the causes of the failures, implications of the failures for similar MOVs, and the comprehensiveness of the corrective actions. These failures were then reviewed within the context of PSE&G's methodology to track and trend MOV performance as described in the MOV program procedure Appendix 18, "MOV Tracking and Trending Assessment."

b. Observations and Findings

Torque Switch Failure of 22CC3

During differential pressure (DP) testing of the CC pump discharge header isolation valve 22CC3 using a variable transformer (i.e., VARIAC) to simulate degraded voltage conditions, the torque switch failed to open even though the valve closed. The motor stalled at a torque value of about 5 ft-lb below the torque switch trip value of 352 ft-lb. The licensee disassembled the actuator and found no significant mechanical conditions which confirmed the initial thoughts that the actuator was not the cause of the failure. PSE&G also reviewed the VOTES diagnostic trace, disassembled the motor, and found no abnormalities. The motor was then sent to Liberty Technologies for further evaluation off site. Tests of the motor were not conclusive in determining why the motor stalled during the DP test.

PSE&G replaced the motor on 22CC3 and performed the DP test successfully. However, PSE&G is still evaluating the 22CC3 failure under an open Action Request and has postulated that the motor may have stalled because of loose cable connections associated with the variac used for this degraded voltage test. Further motor disassembly and inspection was being evaluated to better define the root cause of the problem. The inspectors concluded that PSE&G was evaluating this problem consistent with the requirements of the GL 89-10 program.

Incorrect Torque Switch Setting of 22SW17

Service water isolation valve 22SW17 is a limit-seated butterfly valve which has a torque switch wired in series with the limit switch. The torque switch is generally not actuated and it is set to trip at maximum allowable torque for component protection. On September 4, 1996, PSE&G operations closed 22SW17 under dynamic loading but did not receive the closed indication. While the valve fully closed, there appeared to be an indication problem. Operations informed the Salem MOV program manager who initiated corrective actions to review this and other similar MOVs for this problem.

On November 1, 1996, during DP testing, 22SW17 failed to fully close on its limit switch. Action Request 961101135 was issued to take appropriate corrective actions. PSE&G discovered that the torque switch setting was erroneously set to 1.0 in lieu of the correct setting of 1.5 for both the open and close directions. This setting prematurely deenergized the motor causing the valve to stop before reaching its full closed position. In the subsequent investigation, the licensee determined that maintenance personnel had removed the valve and actuator to the maintenance shop and inadvertently changed the torque switch setting during "bench testing" in the shop. PSE&G concluded that the incorrect torque switch setting was due to human error in that new personnel were at fault for not restoring the torque switch to its proper setting. The inspector noted that the lack of independent verification of maintenance activities involving torque switch settings during the maintenance shop work contributed to the failure of 22SW17.

As corrective actions per AR 9611001135, PSE&G was verifying the torque switch setpoint for each of the limit-seated butterfly valves and other limit seated valves. In addition, PSE&G will revise the MMIS data base by providing only the maximum torque value and torque switch setting for limit-seated MOVs. This should eliminate erroneous use of the minimum torque setpoint which is not applicable for limit-seated MOVs.

The inspectors considered the corrective action for the 22SW17 valve to be adequate. However, it was noted that the licensee could enhance its independent verification process in its MOV maintenance procedures. The inspectors considered this to be an area of weakness requiring thorough licensee evaluation before closeout of AR 9611001135. The inspectors had no further comments.

Tracking and Trending

The inspectors verified that the licensee has an adequate program, in place, to annually examine pertinent MOV documentation for trending purposes. The inspectors noted that a detailed database was implemented in order to track MOV test data and MOV failures. The inspectors noted that overall parameters for monitoring MOV performance were well-defined and properly implemented for tracking and trending purposes. The annual MOV review will be fully documented in accordance with the requirements of the Salem corrective action program.

c. Conclusions

The inspectors concluded that PSE&G was adequately addressing MOV performance problems by taking appropriate corrective actions. PSE&G had developed a good MOV tracking and trending program.

E1.7 Post Maintenance Testing

a. Inspection Scope

The inspectors reviewed Salem's MOV post maintenance testing (PMT) practices as described in procedure NC.NA-AP.ZZ-0050(Q), "Station Testing Program."

b. Observations and Findings

The inspectors verified that the licensee's procedure adequately described the process of identifying PMT and ensured that components or systems perform as intended when returned to service, following corrective or preventive maintenance activities. In addition, PSE&G adequately defined maintenance activities which would create the need for a PMT of the affected component or system.

c. Conclusions

The inspectors concluded that PSE&G established and implemented an adequate MOV PMT program as recommended by GL 89-10.

E1.8 MOV Program Administration

a. Inspection Scope

The inspectors reviewed the governing MOV program procedure NC.DE-PS.ZZ-0033(Q) and supporting appendices throughout the inspection and observed how the various implementing procedures were controlled to fulfill program requirements. This review included the licensee's efforts regarding periodic verification of MOV design basis capability in response to GL 96-05.

b. Observations and Findings

PSE&G prepared a sound Engineering Evaluation S-C-VAR-NEE-1117 to present the Salem Unit 2 MOV information in an organized manner for this inspection. The MOV staff demonstrated a thorough understanding of the MOV issues in presenting the MOV program for closure. The inspectors requested that PSE&G formally revise Engineering Evaluation S-C-VAR-NEE-1117 to include the changes discussed during this inspection. Consistent with the Salem Quality Assurance program requirements, PSE&G recognized the need to update the MOV program procedure NC.DE-PS.ZZ-0033(Q) and associated MOV calculations to be consistent with the information presented during this inspection.

The inspectors reviewed Salem's MOV periodic verification program as describe in procedure EE:S-C-VAR-NEE-1117, Rev. 0. The inspectors verified that PSE&G has a surveillance work order in place to perform a recurring task for static testing each MOV of the GL 89-10 program every 5 years or 3 refueling outages, whichever is later.

PSE&G is in the process of determining periodic verification plans for performing dynamic tests of GL 89-10 valves. The inspectors noted that the licensee intends to perform some dynamic testing. This item will be further reviewed under GL 96-05.

c. Conclusions

The inspectors concluded that PSE&G was implementing adequate administrative controls for the Salem Unit 2 MOV program. PSE&G prepared a sound engineering evaluation to present the Salem Unit 2 MOV information in an organized manner for this inspection.

E1.9 Containment Fan Cooling Unit Service Water Isolation Valve Testing

a. Inspection Scope(37751)

The inspector reviewed the licensee's plan for operation of the containment fan cooling units (CFCUs) during a planned Unit 2 Mode 4 entry.

b. Observations and Findings

The inspector attended a Station Operations Review Committee (SORC) meeting and learned that station management planned to enter Mode 4 with two CFCU units operational and with the SW cooling supply isolated and drained for three CFCUs. The CFCUs were removed from service to support installation of a design change package intended to resolve generic service water (SW) pressure transient concerns identified in NRC Generic Letter 96-06.

The SORC approved an operability determination which demonstrated that 2 CFCUs were adequate to support the potential containment cooling requirements for the Mode 4 entry.

The inspector noted that one SORC member questioned whether the drained SW cooling lines presented a containment integrity concern.

The inspector subsequently reviewed the updated final safety analysis report (UFSAR) Table 6.2.-13 which stated, in part, that the SW containment isolation valves had been exempted from Appendix J, Type C leak rate testing since the valves were normally open to support CFCU operation. The inspector questioned whether the basis for the leak rate test exemption as described in the UFSAR remained applicable with the SW lines drained and isolated.

The licensee subsequently prepared, and the SORC approved a 10 CFR 50.59 safety evaluation to revise the UFSAR to clarify the basis for not Type C leak rate testing the SW isolation valves. The 10 CFR 50.59 concluded that these valves did not meet any of the required categories of valves subject to Type C testing. The approved 10 CFR 50.59 adequately addressed the inspector's UFSAR compliance concern.

The inspector noted, however, that NRC follow-up was required to get a fully satisfactory response to the containment integrity question raised at the first SORC meeting. The inspector concluded that the ineffective follow-up demonstrated a weak safety perspective by station management.

c Conclusions

SORC approved a 10 CFR 50.59 which adequately addressed inspectors concern regarding the UFSAR commitments for Type C leak rate testing the CFCU SW cooling line containment isolation valves. Station management demonstrated a weak safety perspective by not ensuring an appropriate response to the containment integrity question raised at the SORC meeting.

E1.10 Surveillance Effectiveness

a. Inspection Scope (61726)

Inspectors monitored Salem staff response to an identified surveillance deficiency.

b. Observations and Findings

As a result of a proposed modification to the control circuitry for automatic operation of the pressurizer Power Operated Relief Valves (PORVs), a system manager discovered that the surveillance procedure for the Pressurizer Overpressure Protection System (POPS) did not completely test the operation of the automatic controls. The surveillance procedure previously required operators to turn off each channel of POPS while technicians inserted a test signal on the input of the circuit. As a result, plant staff had not demonstrated that the output relays actuated as required. The plant staff immediately developed a method to test the circuit from input to output and successfully demonstrated operability of the POPS. The inspectors considered the previous failures to completely demonstrate operability of POPS a non-cited violation, since PSE&G shut down both Salem units to correct long-standing plant deficiencies subjected to NRC enforcement action, and because the Salem staff identified the violation, and took appropriate corrective action. In addition, the violation stemmed from procedure inadequacies existing prior to the Salem shutdown.

The inspectors noted that the Salem Technical Specification Surveillance Improvement Project, phase 2, would probably have detected this type of surveillance deficiency. Since Salem management has not scheduled completion of TSSIP phase 2 until the end of 1997, the inspectors considered it probable that, if not for the implementation of the PORV control circuit modification, Salem staff would have detected the lack of a complete POPS surveillance until well after Salem Unit 2 restart.

c. Conclusions

As a result of a proposed modification, an alert system manager discovered an incomplete surveillance of the circuit for automatic operation of the Pressurizer Overpressure Protection System. Plant staff immediately devised and completed an effective test. The inspectors noted that TSSIP, phase 2, scheduled for completion in late 1997, would have probably discovered this deficiency.

E8 Miscellaneous Engineering Issues

E8.1 Control Room Ventilation Modification Testing

a. Inspection Scope (71707)

Inspectors observed engineering staff actions to insure that the newly modified control room ventilation system met design requirements.

b. Observations and Findings

During the inspection period, the Salem staff expended considerable effort to demonstrate that the ventilation system could develop the required positive pressure in the control room area compared to air pressure in adjacent rooms and the outside air pressure. Although plant management and staff considered the possibility of a license change request to change the licensing basis requirement for differential air pressure, they decided instead to make the system perform as designed. As a result of trouble-shooting activities, such as temporarily covering ventilation dampers to assess air leakage from the control room envelope, plant staff discovered that the switchgear and penetration area ventilation system (SPAVS) pressurized the rooms adjacent to the control room area. The Salem staff identified and corrected the leak paths allowing SPAVS to pressurize areas adjacent to the control room. The engineers subsequently demonstrated the ability of the control room ventilation system to perform its design basis function.

c. Conclusions

The inspectors concluded that the engineering staff conducted appropriate trouble-shooting to determine the cause of control room ventilation performance problems. The Salem managers properly elected to correct system deficiencies rather than change the licensing basis for control room ventilation. As a result of considerable effort, the engineering staff successfully demonstrated the ability of control room ventilation to perform its design function.

E8.2 (Closed) Unresolved Item 50-272 & 311/95-17-02

The inspectors previously identified that a commitment to install a concrete curb at the entrance to each Salem Unit 1 and 2 Emergency Diesel Generator (EDG) cubicle, contained in a July 26, 1978 letter from PSE&G to the NRC, had not been implemented. The purpose of the curbs was to prevent the potential spread of diesel fuel to areas outside of the individual cubicles. The failure to implement the commitment to install the curbs was interpreted as a weakness in the licensee's commitment management processes.

The inspector toured the EDG cubicles at Salem Units 1 and 2 and noted that curbs, fabricated from steel angle (approximately 3 inches high) with caulking, had been installed at the entrance to each Unit 2 EDG cubicle; no curbs had been installed at the Salem Unit 1 EDG cubicles. The licensee indicated that the caulking is resistant to diesel fuel oil.

The inspector reviewed the process that the licensee used to change the commitment from installation of concrete curbs to installation of caulked steel curbs. In response to a request from the inspector, the licensee provided "FORM-4, NUCLEAR BUSINESS UNIT, COMMITMENT CHANGE EVALUATION SUMMARY FORM" which addresses the EDG curb commitment change and was approved on November 1, 1996. The "FORM -4" is an enclosure to the licensee's procedure NC.NA-AP.ZZ-0035(Q), Revision 5, dated December 27, 1995 and is to be used in Step 5.1.4 for "Changes to commitments made to the NRC in response to GLs, Notices of Violations (NOVs), Inspection Report Followup Items, and Bulletins." The inspector noted that "FORM-4" follows the process of the "NEI Guidelines for Managing NRC Commitments - Revision 2", dated December 19, 1995 that was endorsed by NRC letter dated January 24, 1996. Based upon the review of the subject "FORM 4", the inspector found the change in commitment, and installation of the caulked steel curb, to be acceptable.

The inspector noted that the licensee had closed the commitment tracking form for the Unit 1 and 2 commitment without implementing the installation of curbs at the Unit 1 EDG cubicles. The licensee responded to this finding by opening a new commitment, using the Commitment Manager database, to assure installation of the curbs at Unit 1. Based upon installation of the curbs at Unit 2 and the commitment to install the curbs at Unit 1, this item is closed.

E8.3 NRC Restart Item III.1, Unresolved Items 50-272&311 93-80-06, 07, and 08 (Open) - Appendix R jumpers and program discrepancies, including fire barrier penetrations

a. Inspection Scope

NRC Inspection Report 50-272,311/93-80, identified nine Unresolved Items. This inspection addresses three of these items: URI 272/311-93-80-06, non-conservative assumptions, licensee using only one spurious operation per fire incident; URI 272/311-93-80-07, requirement to perform repairs for Hot Shutdown contrary to SER statement; and URI 272/311-93-80-08, licensee method of protecting equipment from damage by fire.

b. Observations and Findings

By letters dated August 2, 1993, and October 26, 1993, the licensee submitted additional information. By letter dated January 25, 1996, the staff sent its evaluation which concluded that Salem's safe shutdown capability was unacceptable because redundant trains of equipment necessary to achieve and maintain hot shutdown conditions may be damaged by a single fire and the licensee's analysis for fire-initiated spurious signals was inconsistent with the established staff positions promulgated in Generic Letters 81-12 and 86-10.

By letters dated June 19, 1996, and December 2, 1996, the licensee committed to implement certain modifications to resolve the NRC concerns. The modifications are needed to meet the requirements of Appendix R to 10 CFR Part 50. These include the installation of isolation transfer switches for the required safe shutdown functions controlled by the alternative shutdown system and the modification of the control circuits for certain motor operated valves in order to resolve the concern about multiple hot-short spurious damage from associated circuits in the fire area. The licensee proposed to implement all of the modifications prior to restart of Unit 1, and, for Unit 2, during the first refueling outage following restart. In response to an NRC request, the licensee provided, in a letter dated February 18, 1997, compensatory measures that will be taken until the modifications are implemented on Unit 2. By letter dated March 17, 1997, the staff determined that reliance on these compensatory measures is not appropriate to provide adequate protection of public health and safety, and, therefore, concluded that the modifications are required to be in place prior to its restart.

c. Conclusions

Pending satisfactory implementation of the modifications proposed by the licensee in its letters of June 19, 1996, and December 2, 1996, the staff concludes that URI 272/311-93-80-06, -07, and -08 remain open. The basis for this conclusion is contained in the NRC letter dated March 17, 1997.

E8.4 (Closed) Unresolved Item 50-272&311/96-06-02: failure to perform a 10 CFR 50.59 safety evaluation for a degraded emergency diesel generator jacket water after-cooler heater condition regarding the UFSAR requirements. The jacket water after-cooler heater was inoperable for approximately one year yet Salem engineers performed no safety evaluation. Subsequently, engineers performed a safety evaluation for this condition and prepared a UFSAR change request to clarify the function of the after-cooler heater. The inspector reviewed the safety evaluation and the UFSAR change request and found they satisfactorily resolved this issue. Management resolved the generic issue of timeliness and adequacy of the 10 CFR 50.59 process as part of the response to NRC Restart Issue III.11, Engineering Problem Resolution, Including Safety Evaluations (NRC Inspection Report 50-272&311/96-16). This unresolved item is closed.

E8.5 (Closed) Violation 50-272&311/96-07-04: failure to evaluate a deviation and submit a report within 60 days of discovery per 10CFR21. On March 15, PSE&G published an industry report that described recent failures of safety related 4.16 KV breakers. PSE&G staff did not report this as required by 10CFR21 until July 1, 1996. Salem staff provided and documented training for licensing, operations, and engineering personnel to heighten awareness of reporting requirements and to improve inter-departmental communication. Additionally, Salem management performed a review of corrective action documents for Salem and Hope Creek to identify any other potentially reportable deficiencies and found none. The inspector considered the corrective actions adequate. This item is closed.

E8.6 (Closed) Unresolved Item 50-272&311/96-12-03: RHR minimum flow line flow indicator was described in the UFSAR but does not exist in the plant. The inspector reviewed UFSAR change notice No. 96-154 and the 10 CFR 50.59 Safety Evaluation for the change. The change deleted the information in UFSAR Section 6.3.5.3 regarding the RHR minimum flow line flow indication. The inspector concluded that this was a satisfactory resolution to the conflict between the UFSAR and the existing plant configuration. The inspector noted that Salem staff had not yet made this change to the UFSAR but the existence of the change notice provided reasonable assurance the staff will make the change. This item is closed.

E8.7 (Closed) Unresolved Item 50-272&311/96-07-01: a fuel handling building sump pump "not running" alarm was mentioned in the UFSAR but does not exist in the plant. The inspector reviewed UFSAR change notice No. 96-121 and the 10 CFR 50.59 Safety Evaluation for the change. The change removed the reference to the alarm and provided additional information regarding monitoring of the sump level. The inspector concluded that this was a satisfactory resolution to the conflict between the UFSAR and the existing plant configuration. The inspector noted that Salem staff had not yet made this change to the UFSAR but the existence of the change notice provided reasonable assurance the staff will make the change. This item is closed.

E8.8 (Closed) Violation 50-311/96-13-01: failure to perform the required Inservice Inspection of the pressurizer spray nozzle inner radius. On August 19, 1996, Salem staff determined that, contrary to the requirements of Technical Specification 4.0.5., engineers had not performed the first 10 year inspection of the pressurizer spray nozzle inner radius weld. The inspector reviewed PSE&G's response to this violation and reviewed documents which provided evidence of the corrective action taken. The inspector found that engineers performed the inspection and the results were satisfactory. Management reviewed the Salem Unit 2 Inservice Inspection database for first 10 year inspections and found one additional pressurizer weld that engineers had not inspected. In the LER Salem staff issued as a result of this event, the licensee committed to perform a similar review for Salem Unit 1 prior to mode 6. The cause of the missed inspections was insufficient administrative control of the computer data input and review. Previously, a vendor was responsible for the data base. Presently, Salem staff controls the database. Also, the database now has inherent program controls linking completed inspections with the inspection schedule, thus providing an extra measure of precaution to prevent missing inspections. The inspector concluded that response and corrective action to this violation was satisfactory. This item is closed.

E8.9 (Closed) Unresolved Item 50-272&311/96-01-04: update FSAR to state that full core off-load is a routine practice during refueling outages. During an inspection, an NRC inspector pointed out that although full core off-load is routine during refueling outages at Salem 1 &2, the FSAR referred to the practice as "unusual". Since then, Salem staff has amended the FSAR to state "The system design considers the need to totally unload a reactor at the time when spent fuel is in the fuel pool." The inspector considers this resolution acceptable. This item is closed.

E8.10 (Closed) Inspector Followup Item 50-272&311/96-08-07: update FSAR to state that full core off-load is a routine practice during refueling outages. This issue is identical to Unresolved Item 50-272&311/96-01-04. This item is closed.

The inspectors updated or closed the following items which had been identified in past MOV program inspections. These items had been identified in Inspection Report 50-272/311/96-11).

E8.11 (Closed) Violation 50-311/96-11-01: In NRC Inspection Report 50-311/96-11 violations were identified concerning inadequate test control measures during dynamic testing conducted on valves 2CV68 and 2CV69 (Charging Header Stop Valves). The inspections determined that the differential pressures assumed by the dynamic test analysis were uncertain because: 1) the upstream pressure instruments did not account for the presence of pressure control valves located between the pressure instruments and the test valves, and 2) the test procedure specified the use of a downstream pressure gage with an abnormally wide range which provided insufficient sensitivity for the expected test conditions. More importantly the questionable test data obtained was used as the valve factor basis for the PORV block valves (2PR6 and 2PR7).

In response to the violation, PSE&G issued Performance Improvement Request No. 00960725067 dated July 29, 1996, and took the following actions:

PSE&G was no longer using the Charging System (2CV68 and 2CV69) testing to justify the valve factors for the PORV block valves. (See Section E1.3 of this report.)

PSE&G personnel retested 2CV68 and 2CV69 and was able to reduce the effect of the upstream pressure drop contributed by pressure control valve 2CV71. This testing resulted in reasonable valve factors except for one test that was still abnormally low. PSE&G personnel were unable to explain this result.

Licensee personnel reviewed other Unit 2 dynamic tests to identify if similar test control mistakes were made. Flow paths were reviewed to identify flow restrictions and pressure instrument locations were evaluated to assess the adequacy of the pressure data that was obtained. Plant walkdowns were also performed in some cases. This review revealed other cases where the pressure instrument locations and the system alignment could be improved. Based on this review, proposed changes to the dynamic test procedures were under consideration at the time of this inspection. PSE&G personnel considered these changes to be enhancements and the existing testing results were not seriously affected by the existing test alignments. Also, a revision was made to the test evaluation procedure to prompt the technician to review the pressure data and ensure that the observed pressures are reasonable. The inspectors noted that a further procedure caution may be appropriate to review overall test conditions and data acquisition when test results appear to be abnormal. Finally, licensee personnel stated that they intend to use continuous pressure data acquisition during future tests (where possible) to improve accuracy of test results.

To assess these licensee's actions, the inspectors reviewed a dynamic test performed on 22SJ40 in November 1994, where the apparent valve factor was 0.11. The inspectors noted that the downstream pressure gauge was left closed during the closing stroke. This was done because the pressure gauge range was limited to 100 psig and leaving it on line would have damaged the gauge. Licensee personnel justified this action because the system flow discharged into the reactor cavity and the back pressure present at the outlet of the test valve was a function of the cavity water level which would have had no significant change and hence minimal impact on the test results. While this item was not identified or documented as part of the licensee's review and corrective actions, the inspectors concluded that PSE&G took adequate corrective actions to resolve the concerns regarding this violation which is now closed.

E8.12 <u>(Closed) Inspector Followup Item 50-311/96-11-02</u>: Complete load sensitive behavior study for Salem Unit 2. To establish an adequate load sensitive behavior margin for MOVs that cannot be dynamically tested, the licensee was expected to analyze Salem's dynamic test results to support the generic letter program assumptions. This study was not available during the last inspection. However, as documented in Section E1.3 of this report, PSE&G has completed an acceptable load sensitive behavior study and has established adequate margins for MOVs at Salem Unit 2. Therefore, the licensee's actions adequately addressed this concern.

E8.13 <u>(Closed) Inspector Followup Item 50-311/96-11-03</u>: Complete stem friction coefficient study for Salem Unit 2. To adequately assess MOV thrust capability under design-basis conditions, the licensee was expected to analyze Salem's stem friction coefficient performance to support the generic letter program assumptions. This study was not available during the last inspection. However, as documented in Section E1.3 of this report, PSE&G has completed an acceptable stem friction coefficient study for Salem Unit 2. The inspectors found the licensee's actions acceptable and considered this item closed.

E8.14 <u>(Closed) Inspector Followup Item 50-311/96-11-04</u>: Revise test feedback method to include margin for valve degradation. PSE&G's methods for feeding back results from the MOV dynamic test program did not include a specific margin for potential valve degradations. However, as documented in Section E1.3 of this report, PSE&G has revised their MOV setup methodology for Salem Unit 2 to specifically include a 5% margin for potential valve degradations. The inspectors found the licensee's actions acceptable and considered this item closed.

E8.15 (Closed) Violation 50-311/96-11-05: Incorrect assumptions in the mechanical design calculations for the residual heat removal suction header valves (2RH1 and 2) resulted in low torque switch settings. The incorrect settings for these risk significant pressure isolation valves created the possibility that they might not close under design-basis conditions since the torque switch was wired in series with the limit switch for these limit-controlled MOVs. PSE&G responded to the Notice of Violation by letter LR-N96332 dated November 1, 1996 that stated the corrective actions to be taken to prevent recurrence.

The inspector specifically verified that PSE&G had corrected the mechanical design calculations for 2RH1 and 2 such that the torque switch settings would not prevent full closure of these MOVs. A heavier spring pack had to be installed for 2RH1 since the required torque output was beyond the capability of the original spring pack. Both valves were then static tested satisfactorily with diagnostics to assure their operability. The inspector also verified that the licensee had checked other limit controlled MOVs, including butterfly valves, and confirmed that they were not impacted similarly. Additional remarks concerning the switch settings and capability of these MOVs are included in Sections E1.3 and E1.4 of this report. The inspector concluded these actions to be appropriate for closing out this item.

E8.16 (Closed) Inspector Followup Item 50-311/96-11-07: Request for PSE&G to increase the capability of marginal MOVs. This issue was addressed again in this report as discussed in Section E1.4. PSE&G has agreed to review measures to improve the capability of certain MOVs in conjunction with periodic verification efforts in response to GL 96-05. The inspectors concluded that these actions were acceptable for closing this item.

E8.17 (Closed) Inspector Follow Item 50-311/96-11-08: Verify MOV switch setting requirements for Pratt service water system butterfly valves. PSE&G had not verified the adequacy of vendor-provided torque requirements for the Pratt butterfly valves that were located in Salem Unit 2's service water system. None of these valves were practicable to test in situ under dynamic conditions. As documented in Section E1.4 of this report, the licensee used the EPRI PPM butterfly model to develop the torque requirements for these valves. Based on PSE&G's application of the PPM in accordance with EPRI's guidance and the NRC's safety evaluation (as it relates to use of the butterfly model), the inspectors found the licensee's actions acceptable and considered this item closed.

E8.18 (Closed) Inspector Followup Item 50-311/96-11-09: An independent assessment of the Salem MOV program to evaluate its readiness for closure was conducted in August 1995 by two individuals who were MOV project members at another nuclear facility. The assessment appeared to be highly constructive with strengths and weaknesses noted and various recommendations presented for assuring Salem MOV program closure. However, PSE&G had not established firm management controls for providing action plans or addressing the other items in the independent assessment report. Action Request (AR) 960725184 was issued to evaluate the independent assessment, incorporate any appropriate recommendations, and complete any necessary changes to the Salem MOV program by October 25, 1996. The inspector reviewed PSE&G's actions to resolve this AR and determined that no new issues were identified in this subsequent review of the MOV program independent assessment. PSE&G was adequately addressing the various recommendations of the independent assessment. The inspector concluded that this issue was resolved.

E8.19 <u>(Open) Unresolved Item 50-311/96-11-10</u>: Resolve configuration control issues regarding the impact on the MOV program due to plant modifications and EOP changes. In June 1996 PSE&G identified a problem concerning past plant changes that had been implemented without appropriate consideration given to the impact on MOV design-basis setpoint documents. These plant changes included design change packages, temporary modifications, and emergency operating procedures. PSE&G issued AR 960607116 to identify comprehensive corrective actions to evaluate and correct potential problems. The inspector reviewed the findings and status regarding these corrective actions and determined that, while substantial progress has been made to resolve this configuration control issue, AR 960607116 has not been completed. The licensee considered that this AR had been completed to provide the assurance that there were no MOV configuration control issues that could impact existing MOV switch settings. The inspector noted that the NRC identified TOL issue on MOVs in Section E1.4 of this report, although only one instance and concluded to have minor safety consequences, challenges the thoroughness of PSE&G's corrective actions of AR 960607116. This item will remain unresolved pending PSE&G's uncompleted actions to address all engineering areas exposed to the configuration control issues in this AR.

E8.20 <u>(Closed) Unresolved Item 50-311/96-11-11</u>: PSE&G had submitted an MOV program closure letter on March 20, 1995, for Unit 2 and had not amended this letter. In light of this fact and the nature and extent of the findings in NRC Inspection Report 50-311/96-11, a question regarding compliance with 10 CFR 50.9, "Completeness and Accuracy of Information" was raised. This issue was identified as an Unresolved Item. The issue was discussed at a public meeting held on November 12, 1996, between PSE&G and the NRC. PSE&G indicated that engineering evaluation A-O-ZZ-MEE-0926 served as a technical basis for the Salem Unit 2 MOV program closure letter. PSE&G maintained that there was no significant negative information that developed subsequent to the March 20, 1995 letter which would have warranted an amended response. MOV changes that were made were considered to be minor enhancements to improve performance and were not significant deviations from the MOV program technical basis.

The inspector determined that the design verifier of engineering evaluation A-O-ZZ-MEE-0926, in accordance with the recommendation of the licensing engineer responsible for the March 20, 1995 letter, had prepared an internal memorandum on March 9, 1995, which summarized the technical basis for how PSE&G had completed requested actions a. through h. of GL 89-10. In reviewing this document and based on interviews with the cognizant technical and licensing staff personnel responsible for the March 20, 1995 letter, the inspector concluded that there were no clear factors regarding MOVs subsequent to this letter that would have warranted an amended response. In this regard the inspector noted that the MOVs of most concern in the internal memorandum of March 9, 1995, were PR6 and 7 and CC131 and 190 and these MOVs continued to be discussed during this inspection. The inspector concluded that PSE&G has been closely monitoring the performance and capability of these MOVs which is consistent with the intent of GL 89-10. In summary, the inspector concluded that the question regarding compliance with 10 CFR 50.9 had been resolved in that there was not a compliance problem. This unresolved item is closed.

E8.21 Review of Updated Final Safety Analysis Report (UFSAR) Commitments

A recent discovery of a licensee operating their facility in a manner contrary to the UFSAR description highlighted the need for a special focused review that compares plant practices, procedures, and/or parameters to the UFSAR descriptions. While performing the inspections documented in this report, the inspector reviewed the applicable portions of the UFSAR that related to the areas inspected. The inspectors verified that it was consistent with the observed plant practices, procedures, and/or parameters.

IV. Plant Support

P8 Miscellaneous EP Issues

P8.1 (Closed) Unresolved Item 50-272&311/96-15-03: description of backup radiological instrumentation in Salem's Emergency Plan was incorrect. The Emergency Plan incorrectly stated that radiological instrumentation was available in the Training Center laboratory for use as backup to the Emergency Offsite Facility, however, technicians did not calibrate that instrumentation. Salem management revised the Emergency Plan to state that backup equipment is available at the station and at other licensed facilities such as Peach Bottom or Limerick. The inspector found this solution acceptable. This item is closed.

P8.2 (Closed) Unresolved Item 50-272&311/96-15-04: description of media training program in Salem's Emergency Plan was incorrect. Salem staff revised the Emergency Plan to accurately describe the present method of informing local media personnel of emergency plan activities. The present method is to send local media an information calendar followed by a phone call inviting them to the annual emergency preparedness exercise. The inspector found the resolution to be satisfactory. This item is closed.

P8.3 (Closed) Violation 50-272 & 311/94-112-05014: incomplete reporting of information to the NRC regarding the April 7, 1994 inadvertent safety injection event. The Salem Emergency Plan required that operators report specific information to the NRC within 60 minutes. The required information includes systems affected, actuations and their initiating signals, causes, effect of event on the plant, and actions taken or planned. The inspector verified that the Emergency Plan, Attachment 5, now provides clear guidance regarding technical information which must be included when reporting emergency events. Also, Attachments 6 and 7 allow operators to assign an additional communicator if necessary. Additionally, in December 1996, NRC inspectors observed mini-drills for Salem/Hope Creek and found that "Offsite notifications were timely, and professionally completed" (NRC Inspection Report 50-272&311/96-18 has details). Inspectors also verified that training modules used to qualify and requalify designated communicators provided sufficient information relative to reporting. The inspector concluded Salem staff took appropriate action to resolve this violation. This item is closed.

P8.4 (Closed) Violation 50-272 & 311/95-81-04: inadequate equipment to support the emergency response. In October 1995, the control room overhead annunciator alarm system failed and the system provided no indication that the failure had occurred. This condition rendered the equipment inoperable so that PSE&G staff was not able to meet the requirements of the Emergency Classification Guide (ECG). Section 10 of the ECG requires an alert declaration if "Loss of most or all (>75%) overhead annunciators (excluding a scheduled test or maintenance activity for which preplanned compensatory measures have been implemented) and fifteen minutes have elapsed since the loss of annunciators."

PSE&G staff addressed this issue in their response to NRC Restart Issue II.40, Overhead Annunciator Failures. NRC staff conducted a recent inspection to review PSE&G's actions to resolve these equipment problems and the inspectors concluded the corrective action was satisfactory for Salem Unit 2. The inspector documented the results of that inspection in Inspection Report 50-272 & 311/96-13. Because the issue is closed for Salem Unit 2 and is being tracked to completion for Unit 1 by NRC Restart Issue II.40, this violation is closed.

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 March 19, 1997. The licensee acknowledged the findings presented.

Licensee representatives were informed of the purpose and scope of the MOV inspection at an entrance meeting conducted on January 13, 1997. Findings were discussed periodically with the licensee throughout the course of the inspection. The inspectors met with the principals listed below on January 17 and January 24, 1997 at which time a final exit meeting with the licensee was conducted to summarize preliminary inspection findings. The licensee acknowledged the preliminary findings and conclusions, with no exceptions taken. The bases for the inspection conclusions did not involve proprietary information, nor was any such information included in this inspection report, except for the MPR Associates TB and PL analyses reviewed by NRR and referred to in Section E1.5.

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

X3 Management Meeting Summary

On February 5, 1997,Mr. Leonard J. Callan, NRR Executive Director for Operations visited the Salem site. A copy of the licensee handout is attached.

INSPECTION PROCEDURES USED

TI 2515/109:	Inspection Requirements for Generic Letter 89-10, Safety-Related Motor-Operated Valve Testing and Surveillance
IP 37551:	Onsite Engineering
IP 50001:	Steam Generator Replacement Inspection
IP 61726:	Surveillance Observations
IP 62707:	Maintenance Observations
IP 71707:	Plant Operations
IP 92901:	Followup - Plant Operations

ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

50-272&311/97-03-01	VIO	operator training and qualification
50-311/97-03-02	IFI	management commitment process
50-311/97-03-03	IFI	verify commitment regarding 2RH1 and 2.
50-311/97-03-04	IFI	verify commitment regarding 2PR6 and 7.
50-311/97-03-05	IFI	verify commitment regarding 2CC131 and 190.

Closed

50-272&311/95-024	LER	"Technical Specification Violations: differential pressure of the fuel handling building ventilation system" (discussed in 50-272 and 311/96-06
50-311/96-09	LER	fourteen day followup report regarding 12 hour shift for operations personnel
50-272&311/93-23 (EA 94-003: 01013, 01023, 01033, 01043, 01053, 01063, 01073 & 01083)	VIOs	failure to follow procedures
EA94-112: 04013	VIO	PSE&G staff provided inadequate training
EA94-112: 05014	VIO	incomplete reporting of information to the NRC regarding April 7, 1994 inadvertent safety injection event
272&311/93-15-04	URI	corrective action program weaknesses
50-272&311/94-14-02	VIO	failure to provide adequate training to maintenance personnel
50-272&311/95-07-03	VIO	failure to follow procedures
50-272&311/95-17-02	URI	failure to implement a commitment to install a concrete curb at the entrance to each Salem Unit 1 and 2 EDG cubicle
50-272&311/95-17-03	URI	evaluation of corrective action regarding Salem Unit steam generator tube inspection weaknesses
50-272&311/95-80-01	URI	operability determinations

50-272&311/95-81-04	VIO	inadequate equipment to support the emergency response
50-272&311/96-01-01	VIO	failure to follow procedures
50-272&311/96-01-02	VIO	failure to follow procedures
50-272&311/96-01-04	URI	update FSAR to state that full core off-load is a routine practice during refueling outages
50-272&311/96-06-01	VIO	failure to follow procedures
50-272&311/96-06-02	URI	failure to perform a 10 CFR 50.59 safety evaluation
50-272&311/96-07-01	URI	a fuel handling building sump pump"not running" alarm was mentioned in the UFSAR, but does not exist in the plant
50-272&311/96-07-04	VIO	failure to evaluate a deviation and submit a report within 60 days of discovery per 10 CFR 21
50-272&311/96-08-05	VIO	inadequate procedures
50-272&311/96-08-06	URI	Salem Unit 2 operating license does not permit 12 hour operating shifts
50-272&311/96-08-07	IFI	update FSAR to state that full core off-load is a routine practice during refueling outages
50-311/96-11-01	VIO	Inadequate test control and application of MOV test data
50-311/96-11-02	IFI	Basis for load sensitive behavior margin used in thrust calculations
50-311/96-11-03	IFI	Basis for stem friction coefficient used in thrust calculations
50-311/96-11-04	IFI	Basis for valve degradation margin used in thrust calculations
50-311/96-11-05	VIO	Inadequate design control of switch settings for MOVs 2RH1 and 2
50-311/96-11-07	IFI	Request to improve thrust margin for selected MOVs
50-311/96-11-08	IFI	Evaluate torque requirements for Pratt butterfly valves
50-311/96-11-09	IFI	PSE&G to evaluate and document response to MOV program independent assessment
50-311/96-11-11	URI	Resolve question regarding Salem Unit 2 MOV program completion in the context of 10 CFR 50.9(b)
50-272&311/96-12-03	URI	RHR minimum flow line flow indicator was described in UFSAR, but does not exist in the plant
50-311/96-13-01	VIO	failure to perform the required inservice inspection of the pressurizer spray nozzle inner radius
50-272&311/96-15-02	VIO	failure to follow procedures

50-272&311/96-15-03	URI	description of backup radiological instrumentation in Salem's Emergency Plan was incorrect
50-272&311/96-15-04	URI	description of media training program in Salem's Emergency Plan was incorrect
50-272&311/96-17-01	VIO	failure to perform a safety evaluation in accordance with 10 CFR 50.59

Discussed

50-272&311/93-80-06	URI	non-conservative assumptions, licensee using only one spurious operation per fire incident
50-272&311/93-80-07	URI	requirement to perform repairs for Hot Shutdown contrary to SER statement
50-272&311/93-80-08	URI	licensee method of protecting equipment from damage by fire
50-311/96-11-10	URI	review PSE&G's corrective actions to resolve design interface problem regarding impact on MOVs from modifications and EOP changes

LIST OF ACRONYMS USED

AIT	Augmented Inspection Team
AR	Action Request
ATS	Action Tracking System
CAP	Corrective Action Program
CC	Component Cooling
CFR	Code of Federal Regulations
CFCU	Containment Fan Cooler Unit
DP	Differential Pressure
ECG	Emergency Classification Guide
ECG	Emergency Classification Guide
EDG	Emergency Diesel Generator
EMIS	Equipment Malfunction Identification System
EPRI	Electric Power Research Institute
GL	Generic Letter
IR	Inspection Report
LCO	Limiting Condition for Operation
M&TE	Measuring and Test Equipment
MMIS	Managed Maintenance Information System
MOVs	Motor-Operated Valves
MRC	Management Review Committee
NBU	Nuclear Business Unit
NOVs	Notices of Violations
NRC	Nuclear Regulatory Commission
PDR	Public Document Room
PIR	Performance Improvement Request
PL	Pressure Locking
PMT	Post Maintenance Testing
PORV	Power Operated Relief Valve
PPM	Performance Prediction Model
PPP	Performance Prediction Program
PSE&G	Public Service Electric and Gas
RCP	Reactor Coolant Pump
RCS	Reactor Coolant System
RHR	Residual Heat Removal
SE	Safety Evaluation
SNM	Special Nuclear Material
SROs	Senior Reactor Operators
STA	Shift Technical Advisor
TB	Thermal Binding
TOL	Thermal Overload
TS	Technical Specifications
TSSIP	Technical Specification Surveillance Improvement Program
UFSAR	Updated Final Safety Analysis Report
WIN	Work-it-Now

ATTACHMENT

PUBLIC SERVICE ELECTRIC AND GAS
SALEM NUCLEAR GENERATING STATION
GENERIC LETTER 89-10 PROGRAM

PURPOSE OF MEETING

A) DISCUSS UNRESOLVED ITEM FOR THE MOV PROGRAM CLOSURE

B) DISCUSS ACTIONS REQUIRED BY PSE&G BEFORE RESTART

(A)

GENERIC LETTER 89-10
CHRONOLOGY OF EVENTS

Event	Date
Salem 2 Closure Letter	3/20/95
Salem 1&2 begin extended shutdown	6/1/95
PECO Third Party Assessment	8/25/95 - 8/31/95
PECO Assessment presented to PSE&G Mgt.	9/7/95
MOV Eng. Comments on PECO assessment to Mgt.	9/28/95
PECO Assessment Report issued	10/5/95
Hope Creek closure inspection	Feb-96
Outage shifts to Unit 2	3/15/96
Salem 1 Closure Letter	6/25/96
N Insp	7/2 7/

{1}

{2}

{3}

11/12/96

(A)

(1)BASIS FOR SALEM 2 CLOSURE SUBMITTAL

CLOSURE LETTER SENT 3/20/95 UPON COMPLETION OF 2R08

- ITEMS A THROUGH H CONSIDERED COMPLETE
- DOCUMENTATION FOR EACH VALVE EXISTED IN INDIVIDUAL EVALUATIONS

ENGINEERING EVALUATION A-O-ZZ-MEE-0926 ISSUED 12/23/94 JUSTIFIED ASSUMPTIONS BASED ON ANALYSIS OF EPRI DATA

- 0.5 VALVE FACTOR
- 0.15 STEM COEFFICIENT
- 30 % MARGIN

DP TESTING JUSTIFIED THAT PROGRAM ASSUMPTIONS WERE GOOD PREDICTORS OF VALVE THRUST REQUIREMENTS

- EXCEPTIONS WERE EVALUATED ON A CASE BY CASE BASIS BY APPROVED PROCEDURES AND THE TARGET THRUST WAS INCREASED (SEE FIGURE 1)

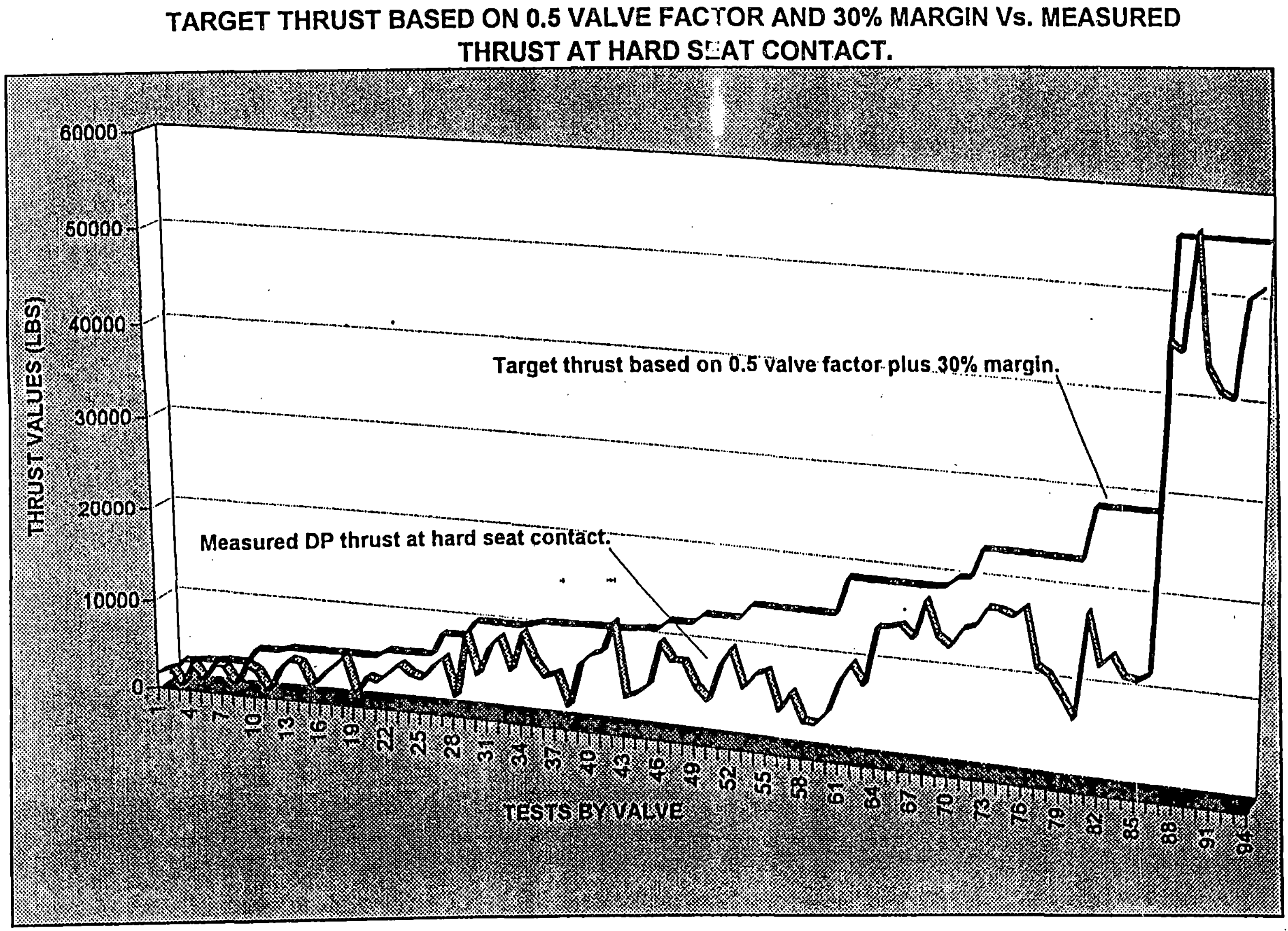
TARGET THRUST BASED ON 0.5 VALVE FACTOR AND 30% MARGIN Vs. MEASURED THRUST AT HARD SEAT CONTACT.
THRUST VALUES (LBS)
60000
50000
40000
30000
20000
10000
0
Target thrust based on 0.5 valve factor plus 30% margin.
Measured DP thrust at hard seat contact.
TESTS BY VALVE
1
4
7
10
13
16
19
22
25
28
31
34
37
40
43
46
49
52
55
58
61
64
67
70
73
76
79
82
85
88
91
94

Figure 1

(A)

(2) *REASON FOR THIRD PARTY ASSESSMENT*

ASSESSMENT WAS REQUESTED AS PART OF A REVIEW OF ALL ENGINEERING PROGRAMS FOR RESTART IN AUGUST, 1995

THE MOV PROGRAM WAS ONE OF THE PROGRAMS THAT WAS REVIEWED

THERE WERE NO SPECIFIC CONCERNS REGARDING THE MOV PROGRAM WHICH INITIATED THE ASSESSMENT REQUEST

(A)

(2) THIRD PARTY ASSESSMENT

RESULTS IDENTIFIED STRENGTHS, WEAKNESSES AND RISKS TO CLOSURE

RESULTS COMMUNICATED TO MANAGEMENT

- PRESENTATION BY PECO TO PSE&G MANAGEMENT 9/7/95
- MOV ENGINEER MEMO SUMMARIZED RESULTS 9/28/95
- FINAL REPORT ISSUED 10/5/95

RESULTS NOT ENTERED INTO CORRECTIVE ACTION PROGRAM

- NEW PROGRAM
- UNDER A STARTUP AND LEARNING CURVE
- PROGRAM WEAKNESSES WERE NOT CONSIDERED CONDITIONS ADVERSE TO QUALITY

ACTIONS TAKEN IN RESPONSE TO WEAKNESSES WERE NOT WELL DOCUMENTED

(A)

(2) RESPONSE TO THIRD PARTY ASSESSMENT

ADDITIONAL STATIC AND DP TESTING WAS SCHEDULED

PRESENTATION WAS MADE TO MRC IN SEPTEMBER, 1995 (MTG. 95-035). IMPORTANCE OF ADDITIONAL STATIC AND DP TESTING TO SUPPORT CLOSURE WAS EMPHASIZED

THE REVISED CLOSURE DOCUMENT COMPLETION WAS BASED ON THE OUTAGE SCHEDULE. COMPLETION DATES SLIPPED AS THE OUTAGE SCHEDULE CHANGED. THE LAST PUBLISHED DUE DATE WAS 6/30/96

THE EXISTING SALEM 2 CLOSURE DOCUMENT EE: S-C-ZZ-MEE-0906 WAS SUPERSEDED BY EE: S-C-VAR-NEE-1117 SCHEDULED TO BE COMPLETED BY NOVEMBER 30,1996

(A)

(2) SALEM RESTART PLANS

(SEPTEMBER, 1995)

CLOSURE FOCUS SHIFTED FROM EPRI AND INDUSTRY DATA TO SALEM SPECIFIC DATA FOR JUSTIFICATION OF ENGINEERING ASSUMPTIONS.

A SIGNIFICANT AMOUNT OF ADDITIONAL STATIC TESTING WAS SCHEDULED TO INCREASE MARGIN

- UNIT I - 36 STATIC VOTES TESTS, 4 VALVE INTERNAL DCP's, 3 SPRING PACK / GEAR RATIO DCP's
- UNIT 2 - 30 STATIC VOTES TESTS

ADDITIONAL DP TESTING WAS SCHEDULED TO PROVIDE GREATER CONFIDENCE IN ENGINEERING ASSUMPTIONS

- UNIT 1 - 16 DP TESTS SCHEDULED
- UNIT 2 - 11 DP TESTS SCHEDULED

(A)

(3) BASIS FOR SALEM 1 CLOSURE SUBMITTAL

GL 89-10 ITEMS A THROUGH H WERE CONSIDERED COMPLETE. AS PART OF THE IMPROVEMENT PLAN, ADDITIONAL TESTING WAS SCHEDULED TO INCREASE MARGIN

LICENSING WAS REQUESTED TO PROVIDE UNIT 1 SCHEDULE INFORMATION TO ENABLE NRC TO INITIATE THE CLOSURE REVIEW PROCESS. UNIT 1 WAS THE LEAD RESTART UNIT AT THAT TIME

TENTATIVE MID-JULY, 1996 CLOSURE INSPECTION DATE WAS ESTABLISHED IN FEBRUARY, 1996 BASED ON COMPLETION OF UNIT 1 MOV WORK IN EARLY APRIL, 1996

RESTART PRIORITY SHIFTED IN MARCH, 1996 FROM UNIT 1 TO UNIT 2. ALTHOUGH ITEMS A THROUGH H WERE CONSIDERED COMPLETE, MARGIN ENHANCEMENT ACTIVITIES WERE NOT COMPLETED

THE NRC WAS NOT REQUESTED TO RESCHEDULE THE CLOSURE INSPECTION BASED ON THE CHANGE IN THE LEAD RESTART UNIT

SALEM UNIT 1 CLOSURE LETTER ISSUED JUNE, 1996

SUMMARY

SALEM CLOSURE BASED ON DP TEST RESULTS AND INDUSTRY EXPERIENCE

SALEM STAFF BELIEVED THAT THE ISSUES IDENTIFIED IN THE THIRD PARTY ASSESSMENT DID NOT CHALLENGE THE ABILITY TO CLOSE GL 89-10

PSE&G FAILED TO CONSIDER THE IMPACT OF THE CHANGE OF THE LEAD RESTART UNIT AND SCHEDULE SLIPPAGE ON THE SCHEDULE FOR THE CLOSURE

(B)

ACTIONS REQUIRED FOR SALEM 2 RESTART

TEST CONTROL VIOLATION (CV68 & 69)

- TEST PROCEDURES REVISED
- VALVES RE-TESTED
- NO GENERIC ISSUES WERE DISCOVERED
- UNIT 2 COMPLETED - SEPTEMBER, 1996

DESIGN CONTROL VIOLATION (RH1 & RH2)

- CALCULATIONS REVISED
- VALVES RE-TESTED
- NO GENERIC ISSUES WERE DISCOVERED
- UNIT 2 COMPLETED - AUGUST, 1996

(B)

ACTIONS REQUIRED FOR SALEM 2 RESTART

CLOSURE DOCUMENT

- ENGINEERING EVALUATION TO BE APPROVED BY NOV. 30, 1996
  - » BASIS FOR ENGINEERING ASSUMPTIONS
  - » JUSTIFICATION FOR VALVE FAMILIES
- UNIT 2 CALCULATION REVISIONS, IF REQUIRED, TO BE COMPLETE BY MODE 2

(B)

ACTIONS REQUIRED FOR SALEM 2 RESTART

JUSTIFICATION FOR VALVES IN UNIT 2 FAMILIES 3 AND 9.1 WILL BE ENHANCED PRIOR TO MODE 6

CONFIGURATION CONTROL

- OVER 400 DCP's REVIEWED WITH MINIMAL IMPACT - COMPLETE
- REVISED EOP's AND AOP's REVIEWED WITH MINIMAL IMPACT - COMPLETE
- TRAINING OF OPERATIONS PROCEDURE WRITING STAFF TO PREVENT RECURRENCE - COMPLETE

STATUS OF ADDITIONAL DIFFERENTIAL PRESSURE TESTING

- 16 UNIT 2 VALVES TESTED, THE ONE TEST REMAINING REQUIRES THE CONDENSATE SYSTEM TO BE IN SERVICE. WILL COMPLETE PRIOR TO MODE 3.

(B)

ACTIONS REQUIRED FOLLOWING SALEM 2 RESTART

REVISE AND UPDATE MOV PROGRAM DOCUMENTATION FOR ENHANCEMENTS BY MARCH 31, 1997

- CALCULATION REVISIONS
- PROGRAM DOCUMENTATION ENHANCEMENTS