U. S. NUCLEAR REGULATORY COMMISSION

REGION I

Docket Nos:	50-272, 50-311
License Nos:	DPR-70, DPR-75
Report No.	50-272/97-18, 50-311/97-18
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:	September 8, 1997 - October 19, 1997
Inspectors:	M. G. Evans, Senior Resident Inspector R. K. Lorson, Resident Inspector F. J. Laughlin, Resident Inspector H. K. Nieh, Resident Inspector J. D. Noggle, Senior Radiation Specialist
Approved by:	James C. Linville, Chief, Projects Branch 3 Division of Reactor Projects

9711250211 971118
PDR ADOCK 05000272
G PDR

EXECUTIVE SUMMARY

Salem Nuclear Generating Station
NRC Inspection Report 50-272/97-18, 50-311/97-18

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

Operations

- The operators responded very well to the October 2 feedwater transient and subsequent manual reactor trip and followed plant procedures. Overall, the licensee's follow up response to the trip was adequate. Station Operations Review Committee performance was good in that they delayed the restart until more troubleshooting could be performed for the steam generator steam line flow indication discrepancies. Although the licensee was unable to fully understand these discrepancies prior to plant restart, they did appropriately monitor steam line flows during startup.

- Licensee personnel conducted Advanced Digital Feedwater Control System testing in a controlled and coordinated manner. The pre-test briefings were well-prepared, thorough, and covered related events from industry experience. The licensee took a positive initiative to perform the evolutions in the simulator prior to actual conduct of the tests. In addition, the licensee analyzed a rod motion anomaly in a controlled and logical manner and took adequate corrective actions.

- Although the licensee's investigation of the inappropriate removal of a control room radiation monitor was generally good, they failed to investigate the interface between the operations and craft personnel, which was a weakness.

- The intermediate head portion of the Unit 2 safety injection system was properly aligned for the existing plant conditions and capable of performing its design safety function. Overall material condition of the safety injection system was good, and adequate system configuration control procedures have been implemented.

Maintenance

- The licensee's troubleshooting of the failure of the 22 steam generator channel II and III steam flow transmitters was appropriate and extensive. Although their efforts were inconclusive, their planning and implementation had improved compared to that of the pressurizer level transmitter troubleshooting discussed in NRC IR 97-15. In addition, the licensee was appropriately pursuing a software change to the Advanced Digital Feedwater Control System to remove an operator burden.

- The failure of the operations department to consult the system engineer when performing a major revision to the procedure for leak testing the boron injection tank isolation valves was a weakness in the interface between operations and engineering. The questioning by shift operators of their ability to successfully perform the test as written within the required Technical Specification time frame was good.

- Overall, the material condition of Unit 2 was good with the noted exceptions of the pressurizer code safety valves and the 22 steam generator steam flow transmitters. The licensee was actively pursuing resolution to these issues and planning for a forced and potentially a planned outage to implement the repairs.

- The licensee took appropriate corrective actions for personnel errors related to Unit 1 maintenance activities.

<u>Engineering</u>

- The licensee adequately addressed two condition reports related to undersized welds on a junction box support for the '1C' emergency diesel generator and the lack of qualification assessment of several contract engineering personnel. The licensee's failure to properly initiate the qualification process for these individuals prior to using them as System Managers was a weakness.

<u>Plant Support</u>

- The inadvertent isolation of fire protection water to the Unit 1 and 2 auxiliary buildings and containments degraded the post-fire safe shutdown capability of Salem Unit 2, which was operating at 55% reactor power at the time of the event. The licensee met all reporting requirements for this occurrence, took adequate immediate corrective actions, but their additional corrective actions identified in their Special Report were not of sufficient scope to address the issues which contributed to this event. In addition, this isolation of fire water along with the inappropriate removal of a control room radiation monitor demonstrated weaknesses in the review and oversight by control room operations personnel of work activities performed by contracted craft personnel in the control room related to Unit 1 which affected Unit 2 operations.

TABLE OF CONTENTS

Report Details

Summary of Plant Status

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

Unit 2 began the inspection period in Mode 1 at 47% power and reached 100% power on September 23, 1997. On September 30, power was reduced to 45% in response to high hot well conductivity and slow loss of condenser vacuum. The unit returned to 100% power on October 1. On October 2, the reactor was manually tripped following a main feedwater flow transient. The unit was restarted on October 6, and 100% power was achieved on October 13. The unit remained at 100% power through the end of the report period.

I. Operations

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

O1.1 General Comments

Using Inspection Procedure 71707, the inspectors conducted frequent reviews of ongoing plant operations. In general, the conduct of operations was professional and safety-conscious. For example, operators demonstrated good use of procedures and excellent communications in responding to the September 30 high hot well conductivity and slow loss of condenser vacuum. Additional, specific events and noteworthy observations are detailed in the sections below.

O1.2 Salem Unit 2 Manual Reactor Trip

a. Inspection Scope

The inspector responded to the control room and observed the operators' response to a main feedwater flow transient which resulted in a manual reactor trip. The inspectors reviewed licensee follow-up activities prior to the plant restart, reviewed the licensee's post trip review procedure SC.OP-AP.ZZ-0101(Z), "Reactor Trip/Safety Injection Review Report" and discussed the identified issues with licensee personnel. In addition, the inspectors attended the Station Operations Review Committee (SORC) meeting on October 4, 1997 at which the findings of the post trip procedure were addressed.

b. Observations and Findings

At 7:13 a.m. on October 2, 1997, with Salem Unit 2 operating at 100% power, the reactor operator initiated a manual reactor trip after recognizing that the two steam generator feed pumps (SGFPs) had automatically tripped. The SGFPs tripped on low suction pressure as a result of a main feedwater flow transient. This transient resulted in the main feedwater pump indicated discharge pressure decreasing from a steady state value of 905 psig to approximately 765 psig. Main steam header pressure remained at approximately 765 psig. Since SGFP speed is developed based on the differential pressure between these two parameters, both SGFPs started to increase their speed to re-establish the actual differential pressure to the program value for 100% power (151 psid). With the increase in SGFP speed, the feedwater suction pressure began decreasing until the SGFPs tripped on low suction pressure. At 9:55 a.m. the licensee reported this event to the NRC via the Event Notification System.

The control room operators and supervisors responded very well to the transient and followed plant procedures. The licensee found that the cause of the transient was the failure of a circuit card in a data acquisition device that was connected to the three main feedwater transmitter loops. The circuit card failure changed the impedance of the circuit on the three loops. The simultaneous failure of all three pressure loops caused the feedwater control system to transfer all the feedwater control valves and SGFPs to the "manual mode", but only after the system had started to respond to the low differential pressure. The data acquisition device had been previously installed to monitor performance of the advanced digital feedwater control system (ADFCS) throughout the Unit 2 integrated test program. NRC Information Notice (IN) 95-13 addressed the potential for data collection equipment to affect protection system performance. The inspector reviewed this IN and found that the licensee had appropriately addressed the issues discussed in the IN prior to installing this data acquisition device.

Plant equipment responded as designed, with the exception of a few minor hardware issues which the licensee corrected prior to restart. However, the licensee's post trip review identified some discrepancies in the data for 22 & 23 steam generator (SG) steam line flow transmitters including that the channel II flow indications were higher than the other channels. Based on conversations with licensee personnel, the inspectors noted some difference of opinion within the engineering organization regarding the need to better understand the high steam line flow data. The SORC performance was good in that they delayed plant restart until more troubleshooting was conducted for the issue. Troubleshooting activities were performed on October 4 and 5. However, the licensee was not successful in understanding the cause of the difference in the channel indications. Licensee management decided to restart the unit on October 6, while monitoring all SG steam line flow channels. During the plant restart, the 22 SG channel II and III steam line flow indicators were significantly higher than all other steam flow transmitters, as discussed in Section M1.2 of this report.

c. Conclusions

The operators and supervisors responded very well to the transient and followed plant procedures. Overall, the licensee's follow-up response to the trip was adequate. Station Operations Review Committee performance was good in that they delayed the restart until more troubleshooting could be performed for the steam generator steam line flow indication discrepancies. Although, the licensee was unable to fully understand these discrepancies prior to plant restart, they did appropriately monitor steam line flows during startup.

O1.3 Unit 2 Advanced Digital Feedwater Control System Testing

a. Inspection Scope

The inspectors observed the following Advanced Digital Feedwater Control System (ADFCS) Special Test Procedures performed as part of the Unit 2 Power Ascension Program: 10% Load Change at 47% Rated Thermal Power (RTP); 25% Load Decrease at 90% RTP; 40% Load Decrease at 90% RTP; and Steam Generator Feed Pump Trip at 90% RTP.

b. Observations and Findings

The purpose of the special test procedures was to confirm that the ADFCS could handle various load decreases and a feed pump trip, without a main turbine or reactor trip. The inspectors attended the pre-test shift briefings for these evolutions conducted by the shift test engineer. These briefings were attended by all personnel involved in the test and were well-prepared, thorough, and covered related events from industry experience. The inspectors concluded that the briefings were very good and provided excellent preparation for the tests. In addition, the licensee had taken a positive initiative to perform the evolutions on the simulator prior to actual conduct of the tests.

The licensee conducted the tests in a controlled and coordinated manner. Communications and procedural adherence were very good. The ADFCS performed as designed, and the acceptance criteria of the tests were satisfied.

During the 25% load decrease, the test engineers noted that rod control bank D had stepped in approximately 7 steps and then stepped out approximately 7 steps during the first 15 seconds of the test. The expected rod control system response to a load decrease is inward rod motion. This outward rod motion anomaly was not detected by the operators performing the test due to its short duration, instead it was identified during review of post test data from the P-250 computer. After the first 15 seconds, control bank D stepped in approximately 85 steps for the remainder of the transient. The licensee determined that function generators of the Hagan 7100 modules used in the rod control system power mismatch circuit were not configured and calibrated properly. This condition likely existed for the life of the plant and was detected at this time because the P-250 computer was installed during the extended outage. Automatic rod speed and direction was declared inoperable because the loop was not functioning within its design basis. The Hagan 7100 modules were re-configured and calibrated to provide the proper outputs for larger power mismatch inputs. The licensee also issued a notice to other Westinghouse plants with similar Hagan 7100 reactor control circuitry. The inspector concluded that the licensee handled the rod motion anomaly in a controlled and logical manner, and that corrective actions were adequate.

c. Conclusions

Licensee personnel conducted Advanced Ditigal Feedwater Control System testing in a controlled and coordinated manner. The pre-test briefings were well-prepared, thorough, and covered related events from industry experience. The licensee took a positive initiative to perform the evolutions in the simulator prior to actual conduct of the tests. In addition, the licensee analyzed a rod motion anomaly in a controlled and logical manner and took adequate corrective actions.

O1.4 Unplanned Entry into Unit 2 Limiting Condition for Operation due to the Inappropriate Removal of a Control Room Radiation Monitor

a. Inspection Scope

On September 5, 1997, the Unit 2 intake duct radiation monitor 1R1B Channel 2 rate meter which was physically located on Unit 1 control panel 1RP1 was removed while it was in operation. This resulted in an inadvertent entry into a Technical Specification limiting condition for operation (LCO) since Unit 2 was in Mode 1. The inspectors reviewed this event including the licensee's evaluation of the root cause and corrective actions.

b. Observations and Findings

Upon removal of the rate meter, Technical Specification LCO action 3.3.3.1b was entered which allowed seven days to return the inoperable channel to operable status. Although the indicator was removed, the 1R1B channel was still capable of performing its intended function because the operation of the actual detection and isolation signal was not affected.

The 1R1B Channel 2 rate meter was improperly removed during implementation of design change package (DCP) 1EC-3244. The radiation monitor had originally been installed by DCP 1EC-3505, package 3, in a spare location on 1RP1 as part of the modifications to a common control room. DCP 1EC-3244 had been issued earlier and contained instructions to remove the spare meter on 1RP1 which was utilized by 1EC-3505, package 3. Although 1EC-3244 had originally been scheduled for installation prior to 1EC-3505, the change in priority from Unit 1 to Unit 2 in 1996 resulted in 1EC-3505 being completed first.

The licensee documented this issue in condition report (CR) 970905072 and concluded that the event occurred due to a combination of events. DCP 1EC-3244 was issued earlier and scheduled to be installed and completed before 1EC-3505. If this had occurred, the event would not have happened. In addition, there was no requirement for the sponsor of the second DCP to notify the sponsor of the first DCP that a change was made which invalidated the modification instructions in the first DCP. Also, the actual removal of the inservice meter involved inattention to detail on the part of the contracted craft personnel as well as the control room operations personnel. When the installation craft workers went to remove the meter, they should have noticed that the meter label on panel 1RP1 no longer was "spare" and that the meter was in operation. In addition, the work activity was reviewed by operations personnel prior to implementation, but they did not recognize this problem before it occurred.

The inspector reviewed the licensee's corrective actions and found them to be extensive and acceptable with the exception that the interface between the control room operations staff and the craft personnel was not identified as an issue in the CR. Therefore it was not evaluated and no corrective actions were identified or taken prior to completing the CR evaluation on October 6, 1997. The inspector discussed this weakness in the evaluation of the event with licensee management and CR 971105184 was issued on November 5, 1997 to further investigate and take corrective actions for this issue. The issue of inappropriate review and oversight by control room operations personnel of work activities performed by contracted craft personnel in the control room related to Unit 1 which affected Unit 2 operations is further discussed in Section F2.1 of this report.

c. Conclusions

Although the licensee's investigation of the inappropriate removal of a control room radiation monitor was generally good, they failed to investigate the interface between the operations and craft personnel, which was a weakness.

O2 Operational Status of Facilities and Equipment

O2.1 Engineered Safety Feature (ESF) System Walkdown

a. Inspection Scope

The inspectors used Inspection Procedure 71707 and walked down accessible portions of the intermediate head safety injection (SJ & SI) system for Unit 2. The inspectors reviewed the Updated Final Safety Analysis Report (UFSAR), plant Technical Specifications (TS), and system operating procedures for background information.

b. Observations and Findings

The inspectors performed a walkdown of all accessible portions of the intermediate head SJ system. The system piping material condition was good, and all accessible valves were in the proper position for the current plant condition. A visual inspection was performed in the 21 SI pump circuit breaker cubicle, and all electrical components were in good condition. Several minor discrepancies were noted and brought to the system manager's attention for disposition. None of the discrepancies involved immediate operability issues.

The inspectors reviewed S2.OP-DL.ZZ-0003, "Salem - Unit 2 Control Room Readings" and Salem operations procedure S2.OP-ST.SJ-0009, "Emergency Core Cooling, ECCS Subsystems - Tavg ≥ 350°F," and determined that the procedures adequately verified the system alignment criteria required by TS surveillances 4.5.2.a.1 and 4.5.2.b.1.

The inspectors also reviewed Salem maintenance procedure S2.IC-FT.RCP-0066, "2PT-948A Containment Pressure Protection Channel IV." The procedure adequately tested functionality of the ESF actuation system circuitry from the 2PT-948A containment pressure transmitter to the solid state protection system input cabinets.

c. Conclusions

The inspectors concluded that the intermediate head portion of the safety injection system was properly aligned for the existing plant conditions and capable of performing its design safety function. Overall material condition of the safety injection system was good, and adequate system configuration control procedures have been implemented.

O8 Miscellaneous Operations Issue

O8.1 (Closed) Licensee Event Report (LER) 50-311/97-010-00, Technical Specification Required Shutdown Due To Position Indication System Anomalies. This LER discussed a plant shutdown on August 18, 1997 when two analog rod position indicators deviated by greater than ± twelve steps from their group position indication. This issue was discussed in NRC Inspection Report 97-15. No new issues were identified in the LER, so this LER is closed.

II. Maintenance

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

M1.1 General Comments

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

- W/O 960830007: Power Range 2N41 Bistable NC302, NC305, and NC306 Adjustment
- W/O 971012110: 2FA17491Z2 Leak Repair
- W/O 980618006: 4 KV Breaker Maintenance, 1B Vital 460/230 Transformer
- W/O 970318103: 11 Service Water Nuclear Header Piping Mods
- W/O 970904074: 21MS96 First Stage Turbine Pressure Instrument Line Steam Leak
- W/O 971006167: 2FT523 and 2FA3472 Read Erroneously
- W/O 971013124: 22 Steam Generator Flow Anomaly
- S2.OP-PT.SJ-0001: 2SJ12 and 2SJ13 Leakage Test
- S2.OP-ST.SJ-0001: Inservice Testing - 21 Safety Injection (SI) Pump
- S1.OP-ST-DG-0001: 1A Diesel Generator Surveillance Test

The inspectors observed that the plant staff performed the maintenance effectively within the requirements of the station maintenance program and that plant staff did the surveillances safely, effectively proving operability of the associated system. However, the licensee-identified issues related to conduct of Unit 1 maintenance activities as discussed in Section M4.1. The 22 SG flow anomaly and the leak test of the boron injection tank isolation valves are further discussed in Sections M1.2. and M1.3.

M1.2 Failure of 22 Steam Generator Steam Flow Channels II and III

a. Inspection Scope

The inspector observed and reviewed activities associated with the failure of the 22 steam generator steam flow channels II and III.

b. Observations and Findings

Following the October 6, 1997 reactor startup, channels II and III of 22 steam generator steam flow drifted up to 70% indicated steam flow when reactor power was actually 17%. This occurred when the turbine generator was synchronized to the grid. These channels use common sensing lines off the main steam line flow venturi. Channel II provides a safety injection function due to high steam flow in coincidence with low-low Tavg or low steam pressure, while channel III provides an input to the digital feed control system.

The licensee entered Technical Specification action statement 3.3.2.1 for channel II as required, and tripped the bistable for the transmitter. Trouble-shooting activities included containment entries to verify the transmitter valve lineup, blowdown the transmitter, and perform thermography on the transmitter condensing pots to ensure adequate water level. The licensee also backfilled the transmitter sensing lines, first to the root valves, and then into the main steam line, to clear any blockage that might exist. These lines were also hydrostatically tested to 850 psi to the root valve, which revealed a leak, however no leak was found. The inspectors found that the licensee's troubleshooting plan and implementation were appropriate and were improved compared to that of the pressurizer level transmitter troubleshooting discussed in NRC IR 97-15.

Channels I, II, and III of the 22 SG steam flow each provide an input to the advanced digital feedwater control system (ADFCS). The ADFCS utilizes a signal validation scheme. This allows a single channel failure without an effect on ADFCS control. However, with two channels inoperable, the licensee had to "force" two loop 2 steam flow signals to predetermined values in order to increase reactor power. This resulted in the disabling of loop 2 steam flow automatic swap-to-manual of the loop 2 feedwater regulating valves and the steam generator feedpumps. Therefore the operators would be required to take manual actions upon failure of the channel I steam flow transmitter or an operational transient. The licensee performed a 10 CFR 50.59 safety evaluation to raise power to 100%, while operating with this degraded condition, and continued the troubleshooting efforts. Power ascension to 100% was completed on October 13, 1997.

At the end of the inspection period, the licensee was continuing with troubleshooting efforts which included additional radiography to determine the condition of the flow venturi in the 22 SG main steam line. In addition, they were pursuing a software change to ADFCS to remove the operator burden associated with "forcing" two loop 2 signals to predetermined values and planning for a forced or potentially planned outage to replace the associated equipment including the flow venturi.

The inspectors found that licensee troubleshooting activities and corrective actions to date were appropriate. Research indicated that the channel II transmitter had a history since 1992, of similar high steam flow indications, however, troubleshooting activities in the past had always been successful in resolving the condition. This transmitter tracked high compared to the other channels following the October 2, reactor trip as discussed in Section O1.2.

c. Conclusions

The licensee's troubleshooting of the failure of the 22 steam generator channel II and III steam flow was appropriate and extensive. Although their efforts were inconclusive, their planning and implementation had improved compared to that of the pressurizer level transmitter troubleshooting discussed in NRC IR 97-15. In addition, the licensee was appropriately pursuing a software change to ADFCS to remove the operator burden associated with "forcing" two loop 2 signals to predetermined values and planning for a forced or potentially a planned outage to replace the associated transmitter hardware, including the flow venturi, if necessary.

M1.3 Leak Test of Boron Injection Tank (BIT) Isolation Valves

The leak test for the BIT isolation valves, 2SJ12 and 2SJ13, is performed in accordance with procedure S2.OP-PT.SJ-0001. The procedure was rewritten following the last acceptable performance in July 1997, with Unit 2 in Mode 5. The test was conducted again on September 22, 1997, with Unit 2 in Mode 1, and valve leakage initially exceeded the maximum allowable (>.05 gpm). At that time, following initial excessive leakage, the procedure required that operators reperform the test using an alternate valve lineup which included closing the BIT inlet valves, to better represent actual dp across the valves. However, closure of the BIT inlet valves results in an entry into a one-hour Technical Specification action statement. The shift operators questioned their ability to successfully perform the test as written within the required Technical Specification time frame and the test was postponed until the procedure was reviewed for adequacy. The procedure was revised (revision 4) and the inspector observed the shift briefing and performance of a subsequent leak test on October 2, 1997, with the unit in Mode 3. The briefing was conducted by the Unit 2 Control Room Supervisor and was adequate for controlling the test. The Operations Superintendent coordinated the leak test in the auxiliary building. The inspector concluded that the licensee conducted the leak test in a controlled manner with adequate operations supervision. Valve leakage during this test was within the allowable limits.

During this inspection, the inspector noted that the system engineer had not been consulted during revision of the procedure between July and September 1997. However, when the September 22 test results were unsatisfactory, the system engineer was consulted at length to write a new revision. The inspector found that although there was no requirement to consult the system engineer when writing an operations procedure, the failure to consult the system engineer when performing a major revision to a technical procedure concerning his/her system was a weakness in the interface between operations and engineering. The questioning by shift operators of their ability to successfully perform the test as written within the required Technical Specification time frame was good.

M2 Maintenance and Material Condition of Facilities and Equipment

Since July 1997, during the Unit 2 restart, the licensee has addressed several equipment material deficiencies including two leaking pressurizer code safety valves, various transmitter failures, numerous secondary side steam leaks and several condenser tube leaks. The pressurizer code safety valves (PR 3 & 4) exhibited leakage prior to the restart in July 1997. On several occasions, operations has attempted to reseat the valves, but without permanent success. The licensee has quantified the leakage at about 0.4 gpm to the pressurizer relief tank and continues to monitor it. In addition, they have procured replacement valves and have the work planned in their forced outage schedule. For the most recent transmitter failure associated with the 22 SG high steam flow discussed in Section M1.2 of this report, the licensee is actively planning for a forced or a potentially planned outage to replace the associated equipment including the flow venturi. The licensee was aggressively pursuing repair of the secondary side steam leaks during operation through leak seal repairs. During the forced outage following the October 2, reactor trip, they implemented permanent repairs for several secondary side leaks.

Overall, the inspectors concluded that the material condition of Unit 2 was good with the noted exceptions of the pressurizer code safety valves and the 22 SG high steam flow transmitters. The licensee was actively pursuing resolution to these issues and planning for a forced and potentially a planned outage to implement the repairs.

M4 Maintenance Staff Knowledge and Performance

M4.1 Conduct of Unit 1 Maintenance Activities

During August and early September 1997, the licensee identified numerous personnel errors related to Unit 1 maintenance activities performed by craft contracted personnel and their supervision. These errors included the performance of a modification on the wrong service water valve and completion of supervisor hold point sign offs on procedures for the condenser hot wells prior to completion of the procedure steps.

The licensee documented these issues as condition reports (CRs), performed investigations concerning the causes of the events and took corrective actions. The licensee found that most of the personnel errors involved procedural non-compliance and lack of attention to detail by the workers and/or supervisors. As a result of the number of issues that were occurring, on September 9, 1997, the licensee held a maintenance work stand down meeting in which the numerous issues as well as procedural compliance and attention to detail were discussed with the workers and their supervision. The inspectors attended the day shift meeting and concluded that it was an appropriate licensee management decision to address the errors that were occurring. In addition, the inspectors reviewed the CRs for the issues discussed above and found that the investigations and corrective actions related to the contracted workers' and supervisors' performance were appropriate. Although the licensee had identified these instances of procedural non-compliance and inattention to detail, the inspectors observed a sample of Unit 1 maintenance activities during the inspection period and noted that the workers were using appropriate work packages and were following the procedures. No procedural non-compliance issues were identified by the inspectors.

The inspectors concluded that the licensee had taken appropriate corrective actions related to these Unit 1 maintenance activities. Although procedural non-compliance is a violation, these failures constitute a violation of minor significance and are being treated as a Non-Cited Violation consistent with Section IV of the NRC Enforcement Policy. **(NCV 50-272/97-18-01)**

III. Engineering

E7 Quality Assurance in Engineering Activities (37551, 40500, 92903)

E7.1 Review of Licensee Evaluation of Condition Reports

a. Inspection Scope

The inspector reviewed the licensee's evaluation of two condition reports (CRs) related to undersized welds on a junction box support for the '1C' emergency diesel generator (EDG) and the lack of qualification assessment of several contract engineering personnel.

b. Observations and Findings

The welds on the thermocouple junction box support for the '1C' EDG were required to be 1/4" per DCP 1EC-3529, package 3. CR 970606335 documented that the welds were up to 1/16" undersized. To address this issue, the licensee had a preliminary analysis performed by a contractor which concluded that even if all the welds in the weld group on the support were 1/16" undersized, the weld stresses would still be within design basis limits and there was no operability concern. The inspector questioned why Quality Verification (QV) personnel accepted the original welds in January 1997 and discussed this issue with QV supervision. The QV supervision stated that the welds were only slightly undersized. That is, they were greater than 3/16", but in some cases slightly under 1/4". The inspector observed the welds in the field with two Level III certified weld inspectors who were not involved with the acceptance of the welds in January, 1997. Based on their inspection, both QV inspectors stated that they would have accepted the welds as found. Therefore , the inspector concluded that it was not unreasonable for the QV inspector to have accepted the welds in January, 1997.

The second CR, 970807217,documented an issue where Raytheon personnel were acting as System Managers and signing off design change packages (DCPs) without evaluation or documentation of their qualifications to work independently. These contracted individuals had been hired in November 1996 to support Salem Unit 1 as specialty services contractors in the position title of "System Test Engineers." The licensee's review found that the individuals had the proper documentation to support qualification as "System Test Engineers." However, in November 1996, the licensee considered these contractors as a resource to alleviate some of the burden of the station System Managers. The intention was to use the individuals as Unit 1 System Managers to allow the station System Managers to focus on Unit 2. Therefore, they received training in the system readiness process on November 15, 1996. This training included the system readiness review process, the initializing and approval process for DCPs, and the use of the system index database system. However, the licensee did not evaluate or document their qualification to work independently as described in PSE&G procedures NC.NA-AP.ZZ-0068, "Control of On-site Contractor Personnel," Section 5.6.3, and NC.TQ-TC.ZZ-0905 (Z), "Training Administration - Engineering Support Personnel Training Program Description," Section 2.5. Specifically, when the licensee began to use these individuals as System Managers, they were not issued job qualification guides (JQGs) and the qualification exemption process was not implemented. This condition was recognized in early 1997, at which time they began to implement the qualification process and the individuals were issued JQGs on January 20, 1997. However, the use of contractor personnel for Unit 1 System Manager functions was discontinued in the first quarter of 1997. This was primarily due to the perception that these contractors were not familiar enough with the assigned systems to relieve the station System Managers of a significant burden. The licensee also stated that the individuals' performance of System Manager tasks prior to implementation of the qualification process was not safety significant because the individuals did have the qualifications required for exemption in the area of DCP review and System Managers do not have a significant responsibility in the DCP process. The licensee intends to develop a contractor control procedure for system engineering to assist in ensuring the staff augmentation and other use of contractors is administered properly.

The inspector concluded that the licensee's failure to properly initiate the qualification process for these individuals prior to using them as System Managers was a weakness in their control of contractors and their subsequent actions taken to address the issue were acceptable.

c. Conclusions

The licensee adequately addressed two condition reports related to undersized welds on a junction box support for the '1C' emergency diesel generator and the lack of qualification assessment of several contract engineering personnel. The licensee's failure to properly initiate the qualification process for these individuals prior to using them as System Managers was a weakness.

E8 Miscellaneous Engineering Issues

E8.1 (Closed) EEI 50-311/97-11-08, involved an apparent violation for failure to update the UFSAR regarding the Unit 2 emergency core cooling system (ECCS) switchover scheme. In NRC letter, Notice of Violation and Exercise of Discretion for NRC IR Nos. 50-272 & 50-311/97-09 and 97-11, dated October 8, 1997, this issue was characterized as a Non-Cited Violation because the failure to update the UFSAR was identified by the licensee during the Salem UFSAR project, and corrective actions were taken to revise the UFSAR. **(NCV 50-311/97-18-02)**

IV. Plant Support

R8 Miscellaneous RP&C Issues (71750)

R8.1 (Closed) Violation 50-272 & 311/97-12-04, failure to annotate the correct LSA group designation on shipping papers. In a previous inspection report (no. 50-272 & 311/97-12), a violation of the new Department of Transportation (DOT) shipping paper requirements was identified. Specifically, radioactive laundry shipping papers did not indicate the appropriate LSA group notation from April 1, 1996 through June 9, 1997 as required by 49CFR172.203(d)(11). Hope Creek and Salem stations ship laundry separate from each other and therefore, a violation was issued to each station.

During this inspection, the inspector reviewed procedure, NC.RP-RW.ZZ-0906(Q), Rev. 2, "Shipment of Radioactive Material" and verified that the LSA group designations are specified in the procedure. The inspector also verified that Salem radioactive laundry shipment no. 97-166 was shipped as LSA-II as required. This violation is closed.

R8.2 (Closed) LER 50-272/97-005, Radioactive Liquid Effluent Samples Not Analyzed Within The Required Surveillance Interval. This LER involved a composite liquid sample that was not analyzed within the required time limits. Chemistry management determined that personnel had mis-interpreted the time requirements for analyzing the samples and conducted training and revised the internal process to ensure prompt delivery of the samples to the vendor for analysis. The inspector concluded that this issue was of minor significance and that the corrective actions appeared adequate. Therefore, it is being treated as a Non-Cited Violation consistent with Section IV of the NRC Enforcement Policy. **(NCV 50-272/97-18-03)**

F2 Status of Fire Protection Facilities and Equipment

F2.1 Inadvertent Isolation of Fire Protection Water To Unit 1 and 2 Auxiliary Buildings and Containments

a. Inspection Scope

The inspector followed up on an event involving the inadvertent closure of valves 1FP186 and 1FP187 which isolated all fire protection water to the Unit 1 and 2 auxiliary buildings and containments.

b. Observations and Findings

On September 16, 1997, a Unit 1 control room operator (CRO) noted that the fire protection isolation valves (1FP186 and 1FP187) to the Unit 1 and 2 auxiliary buildings and containments were closed. This isolated the fire protection water to water deluge systems and hose reels in those buildings. The valves were discovered in the closed condition at 2210 and were reopened at 2237. Other immediate corrective actions included a complete lineup verification of Salem fire protection valves and a twice-per-shift position verification of the two valves in question, pending the completion of a root cause investigation. The licensee submitted a 24-hour report to the NRC at 1711 on September 17, 1997 and followed up with a written report (Special Report 311/97-02) on September 30, 1997, in accordance with License Condition 2.I of the facility operating license.

The licensee performed an extensive root cause investigation and could not determine the exact cause of this occurrence. The investigation determined that the most probable cause was an inadvertent closure of the valves during relamping activities performed by contracted craft workers, on panel 1RP5 where the control push-button for the valves is located. This occurred on or about September 9, 1997, indicating that the valves were shut for approximately seven days. Therefore the licensee attributed the cause to inadequate control of the 1RP5 relamping maintenance activity, both by work planning and control room operators. The cause of the condition going unidentified for about 7 days was attributed to human error due to inattention to detail by the CROs and Loss Prevention personnel during 1RP5 panel reviews. The valves were last verified in the open position during a monthly surveillance (SC.FP-SV.FS-0003(Q), Revision 4) on September 1, 1997. The inspector verified by document review and personnel interview that this surveillance was performed adequately.

Licensee Special Report 50-311/97-03, submitted on October 14,1997, to meet the requirements of Technical Specification 6.9.3, specified the additional corrective actions of 1) A once per shift verification of valve position for 1FP186 and 1FP187 until the 1RP5 panel status report checklist is revised to include verification of the valves' indicator lamp test once per shift, 2) Operator training on the controls associated with the valves, and 3) Issuance of an event notice to affected groups to share the lessons learned from this event. The inspector concluded that these corrective actions were not of sufficient scope to address the issues which contributed to this event. Specifically, there were no corrective actions to address the inadequate work planning which allowed the relamping work on panel 1RP5 with no precautions for pushbuttons which have control functions. Also, no corrective actions addressed inadequate work control by CROs. Lastly, there was no permanent measure to provide for regular local valve position verification of 1FP186 and 1FP187, nor was there any valve position verification by control room CROs.

License Condition 2.C.(10), Fire Protection, states that the licensee shall implement and maintain in effect all provisions of the approved fire protection program as described in the Updated Final Safety Analysis Report (UFSAR). Inadvertent closure of valves 1FP186 and 1FP187 isolated all water-based fire suppression systems in the Unit 1 and 2 auxiliary buildings and containments for several days. The UFSAR, Section 9.5.1.4.1 states that certain equipment is necessary for post-fire safe shutdown (PFSS) of the Salem units, including one charging pump and the auxiliary feedwater (AFW) pumps and other safety-related equipment. That equipment has water suppression systems which were isolated during this event, thus compromising the PFSS capability of Salem Unit 2. Therefore, the closure of valves 1FP186 and 1FP187 is a violation of License Condition 2.C.(10). **(VIO 50-272&311/97-18-04)**

In addition, this issue and the inappropriate removal of a control room radiation monitor discussed in Section O1.4 are examples of weaknesses in the review and oversight by control room operations personnel of work activities performed by contracted craft personnel in the control room related to Unit 1 which affected Unit 2 operations.

c. Conclusions

The inadvertent isolation of fire protection water to the Unit 1 and 2 auxiliary buildings and containments degraded the PFSS capability of Salem Unit 2, which was operating at 55% reactor power. The licensee met all reporting requirements for this occurrence, took adequate immediate corrective actions, but their additional corrective actions identified in their Special Report were not of sufficient scope to address the issues which contributed to this event. In addition, there were weaknesses in the review and oversight by control room operations personnel of work activities performed by contracted craft personnel in the control room related to Unit 1 which affected Unit 2 operations.

V. Management Meetings

X1 Exit Meeting Summary

The inspectors presented the inspection results to members of licensee management at the conclusion of the inspection on October 23, 1997. The licensee acknowledged the findings presented. The inspectors asked the licensee whether any materials examined during the inspection should be considered proprietary. No proprietary information was identified.

X2 NRC Confirmatory Action Letter (CAL) 1-95-009 Modification

In the August 6, 1997 letter, which gave NRC approval for the restart of Salem Unit 2 by modifying CAL 1-95-009, hold points were established at three discrete power levels to allow a planned NRC assessment of Salem Unit 2 performance. During this inspection period, the licensee formally requested and gained NRC concurrence to raise reactor power above 50% on September 11, and above 90% on September 22. The inspectors attended the licensee's Management Review Committee (MRC) meetings associated with both of these holdpoints and found that management was continuing to thoroughly assess their performance in a self-critical manner.

INSPECTION PROCEDURES USED

IP 37551:	Onsite Engineering
IP 40500:	Effectiveness of Licensee Controls in Identifying, Resolving, and Preventing Problems
IP 61726:	Surveillance Observations
IP 62707:	Maintenance Observations
IP 71707:	Plant Operations
IP 71750:	Plant Support Activities
IP 92901:	Plant Operations Followup
IP 92902:	Maintenance Followup
IP 92903:	Engineering Followup
IP 92904:	Plant Support Followup
IP 93702:	Event Followup

ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

50-272&311/97-18-04	VIO	Inadvertent closure of fire protection valves 1FP186 and 1FP187

Closed

50-311/97-11-08	EEI	Apparent violation for failure to update the UFSAR regarding the Unit 2 ECCS switchover scheme
50-272 & 311/97-12-04	VIO	Failure to annotate the correct LSA group designation on shipping papers for laundry shipments between April 1, 1996 and June 9, 1997.
50-272/97-005	LER	Radioactive Liquid Effluent Samples Not Analyzed Within The Required Surveillance Interval.
50-311/97-010	LER	Technical Specification Required Shutdown Due to Position Indication System Anomalies.
50-272/97-18-01	NCV	Procedural Non-Compliance related to Unit 1 Maintenance Activities
50-311/97-18-02	NCV	Failure to update the UFSAR regarding the Unit 2 ECCS switchover scheme
50-272/97-18-03	NCV	Radioactive Liquid Effluent Samples Not Analyzed Within The Required Surveillance Interval
50-311/97-02		Special Report - for Isolation of the Fire Protection Water to Salem 1&2 Auxiliary Buildings and Containments
50-311/97-03		Special Report - for Isolation of the Fire Protection Water to Salem 1&2 Auxiliary Buildings and Containments

Discussed

None

LIST OF ACRONYMS USED

ADFCS	Advanced Digital Feedwater Control System
AFW	Auxiliary Feedwater
BIT	Boron Injection Tank
CAL	Confirmatory Action Letter
CR	Condition Report
CRO	Control Room Operator
DCP	Design Change Package
DOT	Department of Transportation
ECCS	Emergency Core Cooling System
EDG	Emergency Diesel Generator
ESF	Engineered Safety Feature
IN	Information Notice
JQGs	Job Qualification Guides
LCO	Limiting Condition For Operation
LER	Licensee Event Report
MRC	Management Review Committee
NRC	Nuclear Regulatory Commission
PDR	Public Document Room
PFSS	Post-Fire Safe Shutdown
PSE&G	Public Service Electric and Gas
QV	Quality Verification
RTP	Rated Thermal Power
SG	Steam Generator
SGFP	Steam Generator Feed Pump
SJ & SI	Safety Injection
SORC	Station Operations Review Committee
TS	Technical Specification
UFSAR	Updated Final Safety Analysis Report
W/O	Work Order