U. S. NUCLEAR REGULATORY COMMISSION
REGION I

Report Nos. 50-272/91-01
50-311/91-01
50-354/91-01

License Nos. DPR-70
DPR-75
NPF-57

Licensee: Public Service Electric and Gas Company
P.O. Box 236
Hancocks Bridge, New Jersey 08038

Facilities: Salem Nuclear Generating Station
Hope Creek Nuclear Generating Station

Dates: January 1, 1991 - February 12, 1991

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Inspection Summary:
Inspection 50-272/91-01; 50-311/91-01; 50-354/91-01 on January 1, 1991 - February 12, 1991

Areas Inspected: Resident safety inspection of the following areas: operations, radiological controls, maintenance and surveillance testing, emergency preparedness, security, engineering technical support, safety assessment/quality verification, and licensee event reports and open item followup.

Results: The inspectors identified two non-cited violations for Salem. An executive summary follows.

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EXECUTIVE SUMMARY

Salem Inspection Reports 50-272/91-01; 50-311/91-01

Hope Creek Inspection Report 50-354/91-01

January 1, 1991 - February 12, 1991

OPERATIONS (Modules 60705, 60710, 71707, 93702)

Salem: The Salem units were operated in a safe manner. Service water leaks and radiation monitoring system actuations were reported, and licensee actions were appropriate. A letdown system isolation was appropriately responded to; however, a previous unresolved item regarding reportability remains open. Licensee actions and response to a Unit 1 runback were good. Preparations for the Unit 1 ninth refueling outage were excellent.

Hope Creek: The unit was operated in a safe manner during refueling outage conditions. Refueling activities, including reactor core offload, the subsequent reload, and fuel sipping, were effectively controlled.

RADIOLOGICAL CONTROLS (Modules 71707, 93702)

Salem: Periodic inspector observation of station workers and Radiation Protection personnel implementation of radiological controls and protection program requirements did not identify any deficiencies. The radiation hot spot program has been enhanced. The licensee performed well in meeting their 1990 radiation exposure goal.

Hope Creek: Periodic inspector observation of station workers and Radiation Protection personnel implementation of radiological controls and protection program requirements identified one instance of poor work practices. A high number of personnel contamination events occurred during the outage causing the licensee to exceed their aggressive goal. Licensee action was appropriate; however, contaminations continued. The licensee performed well relative to their modified 1990 radiation exposure goal.

MAINTENANCE/SURVEILLANCE (Modules 61726, 62703)

Salem: Routine observations did not identify any deficiencies. Unit 2 residual heat removal room cooler service water piping replacements were proactive and effectively conducted. A maintenance error resulted in a condition outside the design basis for the auxiliary feedwater backup auto-start circuitry, and was noted as a licensee-identified non-cited violation. Failure to perform a Unit 2 diesel test in the required interval was also noted as a licensee-identified non-cited violation.

Hope Creek: Routine observations did not identify any deficiencies. Control rod drive maintenance activities were well planned and efficiently controlled and executed. Containment leak rate testing was determined to be acceptable and the program was evaluated as being well managed.

EMERGENCY PREPAREDNESS (Modules 71707, 93702)

No noteworthy findings were observed.

SECURITY (Modules 71707, 93702)

Routine observation of protected area access and egress showed good control by the licensee. Increased security measures were determined to be proactive. Licensee response to a wounded security officer was appropriate.

ENGINEERING/TECHNICAL SUPPORT (Module 71707)

Salem: Review of the management of engineering work activities determined that they were being performed in accordance with applicable procedures and were being properly prioritized and executed. Licensee response to NRC Region I Regional Administrator tour concerns were appropriate. Service water system pipe replacement program appears to be adequate. Turbine driven auxiliary feedwater pump concerns were aggressively pursued by system engineers. Containment fan coil unit heat removal capability is unresolved for Units 1 and 2 pending completion of licensee testing, inspection, and evaluation, and subsequent NRC review.

Hope Creek: Review of the management of engineering work activities determined that they were being performed in accordance with applicable procedures and were being properly prioritized and executed. A good safety perspective was noted relative to reactor recirculation instrument line leakage.

SAFETY ASSESSMENT/ASSURANCE OF QUALITY (Modules 71707, 90712, 90713, 92700, 92701)

Salem: Licensee response to PWR moderator dilution concerns were appropriate. The Unit 1 and 2 shutdown margin monitor system is unresolved due to system unavailability and absence of Technical Specification requirements.

Hope Creek: Refueling outage activities were generally well controlled and conducted, and effectively managed. However, weaknesses were noted relative to personnel contaminations and housekeeping. The licensee was aggressive in addressing these weaknesses.

DETAILS

1. SUMMARY OF OPERATIONS

1.1 Salem Units 1 and 2

Both Salem units operated at or near full power during the inspection period. Unit 1 was shutdown on February 9, 1991, for its ninth refueling outage.

1.2 Hope Creek

The Hope Creek unit remained in a refueling mode during the report period. The reactor core was offloaded, and the cycle four core was loaded during this period. At the end of the period, final preparations for unit restart were underway.

1.3 Common

NRC Commissioner James Curtiss visited the Hope Creek station on January 22, 1991. Mr. E. Greenman, Assistant Director for Region Reactors (NRR), visited the Salem station on January 11, 1991.

2. OPERATIONS

2.1 Inspection Activities

The inspectors verified that the facilities were operated safely and in conformance with regulatory requirements. Public Service Electric and Gas (PSE&G) Company management control was evaluated by direct observation of activities, tours of the facilities, interviews and discussions with personnel, independent verification of safety system status and Technical Specification compliance, and review of facility records. These inspection activities were conducted in accordance with NRC inspection procedures 60705, 60710, 71707, and 93702. The inspectors performed normal and back-shift inspections, including deep back-shift (10 hours) inspections as follows:

Unit	Inspection Hours	Dates
Salem	4:00 a.m. - 5:00 a.m.	January 13, 1991
	10:00 p.m. - Midnight	February 3, 1991
	Midnight - 1:00 a.m.	February 4, 1991
	4:00 a.m. - 5:00 a.m.	February 4, 1991
	4:00 a.m. - 5:00 a.m.	February 8, 1991
Hope Creek	10:00 p.m. - Midnight	January 12, 1991
	10:00 p.m. - Midnight	February 7, 1991

2.2 Inspection Findings and Significant Plant Events

2.2.1 Salem

A. Service Water (SW) System Leaks

The licensee identified SW system weld and piping leaks as follows:

Unit	Component/Leak	Date	Time
2	Leak at supply SW pipe for No. 21 charging pump room, gear oil, and lube oil coolers	1/10/91	3:55 p.m.
1	Leak at inlet SW pipe for No. 11 residual heat removal room cooler	1/17/91	3:00 p.m.
1	Leaks at outlet SW pipe for No. 1 safety injection room cooler and No. 1 auxiliary feedwater pump room cooler	1/24/91	3:06 p.m.
2	Leak at outlet SW pipe for No. 22 charging pump lube oil cooler	1/30/91	3:15 p.m.

For each occurrence the leak was minimized or isolated, an ENS call was made and the inspector notified, an incident report was written to investigate the cause(s), and the leak was repaired. The inspector reviewed each occurrence, including licensee actions. Discussions were held with licensee personnel. The inspector noted that each leak documented above was identified during the recently implemented weekly piping walkdown, indicating that the licensee's inspection program has been effective in identifying minor leaks.

B. Radiation Monitor Engineered Safety Feature (ESF) Actuations

The following ESF actuations occurred and were reported by the licensee during the period:

Unit	Radiation Monitor	Date	Time
1	1R11A	January 11, 1991	11:08 a.m.
2	2R12A	January 14, 1991	10:15 a.m.
2	2R12A	January 14, 1991	10:27 a.m.
2	2R1A	January 16, 1991	12:18 a.m.
1	1R11A	January 17, 1991	8:50 p.m.
2	2R1A	February 1, 1991	5:29 a.m.

These events continue to be indicative of the degraded radiation monitor system. Systems responded as designed causing a containment ventilation isolation or a control room ventilation start. Licensee actions include short term and long term equipment upgrades. The inspector reviewed licensee actions regarding these events. The licensee intends to submit an LER for these events. No unacceptable conditions were noted.

C. Chemical Volume and Control System (CVCS) Letdown Isolation and Open Item Followup

On January 4, 1991, while operating at 100% power, Unit 1 experienced a CVCS letdown isolation at 9:57 a.m. due to a loss of the 125 volt D.C. control power to two letdown isolation valves. While maintenance technicians were commencing work in the remote Hot Shutdown Panel, an electrical short occurred, resulting in the loss of valve control power. The circuit was repaired, and letdown flow was restored. Unit operation was not significantly affected, and operator response to the minor transient was appropriate.

The inspector questioned the licensee if this event was characterized as an Engineered Safety Feature (ESF) actuation and therefore reportable to the NRC as a four-hour notification per 10CFR50.72 reporting requirements. The two valves which automatically closed (1CV3 and 1CV7) are listed in Technical Specification Table 3.6-1 as Phase "A" Isolation Valves. The licensee subsequently notified the NRC of the event via the Emergency Notification System. However, further review of this event by the licensee concluded that this event was not an ESF actuation since the two letdown valves changed to the fail-safe position (closed) from a non-ESF actuation signal (component failure), and was not a containment isolation (ESF actuation).

The licensee acknowledged weaknesses in their characterization of ESF actuations specific to component actuations due to causes such as a blown fuse or a component failure. Such actuations may not initially be identified as ESF actuations when the ESF logic is not involved (i.e. from an actual ESF sensor reaching its trip setpoint). The inspector concluded that the issue of whether or not a blown fuse or component failure constitutes an ESF actuation should be resolved in order to form a consistent approach to the reporting of ESF actuations.

NRC Unresolved Item No. 50-272/89-26-02 previously identified similar problems in which potential programmatic weaknesses were noted with respect to ESF reporting, particularly of ESF actuations caused by non-ESF designated instrumentation. The inspector noted that the licensee's response to this concern has not yet been completed, and that licensee action remains necessary to resolve reportability concerns.

D. Unit 1 Runback

At 3:10 p.m. on February 6, 1991, a Unit 1 runback from the turbine electrohydraulic control (EHC) system occurred. The unit was initially at 100% power and the EHC runback lowered power to about 92%. An ENS call was made at about 7:00 p.m. Prior to the event, Nuclear Instrument (NI) channel N43 was out of service to adjust the NI detector current setpoint. The associated reactor protection system (RPS) bistables had been tripped as required by Technical Specifications. Licensee troubleshooting determined that an apparent overtemperature differential temperature (OTDT) trip occurred on one of three other RPS channels resulting in the EHC runback. Operators responded in accordance with alarm response and integrated operating procedures.

In accordance with maintenance troubleshooting procedures, licensee instrumentation and calibration (I&C) personnel monitored the three OTDT channels (11, 12, 14). A brush recorder monitored the actual loop differential temperature inputs as well as the differential temperature variable trip setpoints. No abnormalities could be identified, and the licensee concluded that the OTDT trip signal had been spurious. The unit was returned to full power on February 7, 1991.

The inspector discussed this event with operations, I&C, and management personnel, and these personnel were noted as being knowledgeable with regard to the possible causes and consequences of the event. Operator response was determined to be in accordance with procedures. I&C troubleshooting activities were also reviewed and were found to be acceptable. The inspector concluded that the licensee's overall response was good and displayed a safety conscious attitude.

E. Salem Refueling-Outage Preparations

The Salem Unit 1 ninth refueling outage began February 9, 1991. The inspector reviewed selected licensee procedures, plans, schedules, outage goals, design change packages (DCPs), maintenance work items, spare parts availability, inservice inspection activities, radiation protection plans, security plans, restart plans, and quality assurance and quality control (QA/QC) activities. Discussions were held with plant and outage management personnel, and the inspector attended several outage meetings.

Portions of the following procedures were reviewed:

-- new fuel receipt and inspection,
-- fuel handling,
-- administrative controls,
-- reactor vessel assembly and disassembly,
-- abnormal/emergency operating,
-- shutdown cooling operations,
-- integrated operating,
-- surveillance testing,
-- refueling activities,
-- spent fuel pool operations,
-- midloop operations, and
-- inservice inspection.

The inspector concluded that Salem station and management were well prepared for the refueling outage, excepting the availability of spare parts for several DCPs (see NRC Inspection 50-272/90-28). Aggressive outage goals and thorough QA/QC inspection, surveillance, and coverage plans were developed. Workers were briefed on the outage plans, schedule and goals through General Manager meetings and by the use of an information brochure/handout.

F. Open Item Followup

(Closed) Unresolved Item 50-272/89-22-01: Develop and implement corrective actions relative to the improper implementation of Technical Specification (TS) required actions. Unit 1 TS Table 3.3-3 requires that when one channel of the auxiliary feedwater (AFW) system automatic start function from an emergency trip of the main feedwater pumps is inoperable, the affected channel is to be jumpered to start the motor driven AFW pumps upon the loss of the other main feedwater pump. On September 4, 1989, the jumper was not installed as required.

The licensee reviewed this event and submitted LER 89-029 on October 27, 1989. In the LER, the licensee committed to modify procedures AOP-CN-1, "Loss of Feedwater Pump" and OP III-9.3.2, "Feed Pump Operation," to formally require the installation of the temporary jumper. As documented in NRC Inspection Report 50-272/89-22; 50-311/89-20, the licensee found that the Unit 2 TS did not provide a similar requirement for the jumper, although system and actuation design appeared to necessitate such action. The licensee stated that they would administratively implement the actions on both units and that a TS change request would be initiated.

The inspector determined that a TS change request was submitted by the licensee on September 13, 1989, to add the requirement to install the jumper for Unit 2. A review of procedures AOP-CN-1 and OP III-9.3.2 by the inspector found that only the Unit 1 procedures were modified (i.e. no formal mechanism was provided to ensure that the jumper would be installed at Unit 2). The licensee immediately took action to revise the appropriate procedures.

The inspector concluded that the licensee's initial actions were incomplete to fully address this issue, however, the subsequent actions were sufficient and this item is closed.

2.2.2 Hope Creek

A. Refueling Activities

During this period, the Hope Creek reactor core was offloaded into the spent fuel pool and then reloaded into the reactor vessel for cycle four operation. The inspector verified that reactor operators and senior reactor operators were knowledgeable of these refueling activities. Activities were observed from the control room, the refueling bridge and the spent fuel area. Contractor personnel conducting core offload activities were interviewed. The fuel bundle pull sheets were checked, and the core status board was verified to be accurate. Appropriate refueling procedures and Technical Specifications were also reviewed. Source Range Monitor instrumentation was verified to be operating properly and responding to fuel bundle movements. No unacceptable conditions were noted. The inspector concluded that fuel off-load and reload activities were being effectively controlled.

The licensee performed fuel sipping activities in an attempt to locate the defect that had caused higher than normal reactor coolant and offgas radioactivity (see NRC Inspection 50-354/90-16). A contractor (General Electric) performed the fuel sipping in the spent fuel pool. The inspector observed portions of the sipping, reviewed appropriate procedures, and interviewed selected contractor personnel. All fuel bundles reloaded into the core were checked for leakage, and none was found. Once core reload was complete, fuel sipping continued, and one bundle was detected to have a fuel leak. This bundle was not scheduled to be reloaded as it had been in the core for three cycles.

3. RADIOLOGICAL CONTROLS

3.1 Inspection Activities

PSE&G's conformance with the radiological protection program was verified on a periodic basis. These inspection activities were conducted in accordance with NRC inspection procedures 71707 and 93702.

3.2.1 Salem

A. Radiation Work Permits (RWPs)

During periodic tours the inspectors reviewed worker implementation of RWP requirements. On January 11, 1991, a worker and a radiation protection (RP) technician were in partial protective clothing (PC) near the Unit 1 containment personnel air lock. Both were wearing a lab coat; however, the worker did not have his booties taped. A review of procedure RP 202 noted that taping of booties is only required when wearing full PCs. The inspector discussed this issue with RP management and had no further questions at this time.

B. Radiation Hot Spot Program

As stated in NRC Inspection 50-272 and 311/90-24, the inspector identified a concern regarding the identification and control of radiation hot spots. In response, the licensee enhanced the control of this program to include documentation, identification, and computerized tracking of hot spots. RP procedure SC.RP-TI.ZZ.0204(Q) was revised to include these program changes.

The inspector reviewed these changes, verified in-field implementation and discussed this item with RP technicians and management personnel. The inspector concluded that licensee has provided good enhancements to their overall hot spot program.

C. 1990 Personnel Radiation Exposure

The licensee met their 1990 radiation exposure goals as follows:

-- Goal - 300 person-Rem (revised downward from 450 due to the delay of Unit 1 outage)
-- Actual - 296 person-Rem

The 1990 exposure data includes 230 person-Rem that occurred during the Unit 2 outage (March-June). Individual radiation exposure is monitored during radiological controls area (RCA) entry with the use of a computerized system (ALNOR). Current station cumulative exposure is displayed and made highly visible for all personnel by using an electronic sign at the RCA entry. Management formally reviews radiation parameters (including personnel exposure) during management meetings. Also, radiation protection management personnel review exposure data frequently.

The inspector concluded that the Salem station performed well in meeting their 1990 radiation exposure goal. The inspector also noted that the station is effective in tracking and monitoring exposure on a continual basis.

3.2.2 Hope Creek

A. 1990 Personnel Radiation Exposure

The licensee slightly exceeded their 1990 radiation exposure goals as follows:

-- Goal - 180 person-Rem (did not include third refueling outage)
-- Actual - 196 person-Rem

The 1990 actual data includes exposure not in the original estimate such as preparations for and the start of the third refueling outage that was originally scheduled for January 1991.

Individual exposure is monitored during radiological control area (RCA) entry with the use of a computerized system (ALNOR). Current station cumulative exposure is displayed and made highly visible for all personnel by using an electronic sign at the RCA entry. Management formally reviews radiation parameters, including personnel exposure, during weekly management meetings. Radiation protection management personnel review exposure data frequently.

The inspector concluded that the Hope Creek station performed well in pursuit of their 1990 radiation exposure goal. The inspector also noted that the station is effective in tracking and monitoring exposure on a continual basis.

B. Radiation Protection During The Outage

The inspector reviewed the licensee's policy regarding the use of paper filter masks for respiratory protection. The inspector discussed the issue with licensee management, who stated that paper filter masks were not authorized for use in any radiological application per procedure NC.NA-AP.ZZ-0045(Q). Further, their effective use in non-radiological situations would be compromised by leaks and fit problems, resulting in a protection factor (PF) of about zero. Additionally, the licensee was concerned that use of such masks could lead to an increased number of facial contaminations due to the probable need to periodically adjust the mask. The inspector determined that the licensee's approach was appropriate and reflected a conservative perspective toward safe work practices in contaminated areas.

During the outage the inspectors observed an event that displayed poor radiological worker practices. During a tour of the turbine building, the inspectors stopped to observe the disassembly of a reactor feedwater pump turbine. Due to the potential of personnel contamination, the work area had been cordoned off and the personnel performing the work were dressed in anti-contamination clothing. The inspectors noticed that the two contractors routinely touched their faces with their potentially contaminated gloves. When questioned by one of the inspectors, a contractor explained that he was not contaminated because his personal dosimeter still read zero; evidence that the contractor did not adequately understand the difference between radiation dose and contamination. Additionally, while the inspectors were still present, one of the contractors fell over the contaminated area boundary. The contractor subsequently repaired the boundary but again touched unprotected parts of his body while straightening his clothing, and no survey was made of the area in which he fell and possibly contaminated.

The inspectors raised their concern with these practices to the manager of the Chemistry and Radiation Protection Department. The manager acknowledged the inspector's concern and subsequently verified that neither contractor had become contaminated as a result of the event. A number of personnel contaminations, especially facial contaminations, occurred during the outage causing the licensee's goal (i.e., less than 110 events) to be exceeded. The poor work practices observed by the inspectors were acknowledged by the licensee to be a contributing factor. The inspectors will monitor this issue in the Hope Creek post-outage critique and follow-up the licensee's plans for improvement.

4. MAINTENANCE/SURVEILLANCE TESTING

4.1 Maintenance Inspection Activity

The inspectors observed selected maintenance activities on safety-related equipment to ascertain that these activities were conducted in accordance with approved procedures, Technical Specifications, and appropriate industrial codes and standards. These inspections were conducted in accordance with NRC inspection procedure 62703.

Portions of the following activities were observed by the inspector:

Unit	Work Request (WR)/Order (WO) or Procedure	Description
Salem 2	890224119	Inspect inboard and outboard bearings and realign as needed for No. 22 auxiliary feedwater pump
Salem 2	901026073	Install spool piece No. 2S27C (service water pipe; diesel generator cooler)
Salem 1	910206185	Troubleshoot overtemperature delta-temperature instruments
Salem 1	910117066	Investigate and correct "1A" diesel generator load swing during surveillance run
Salem 2	910108143 910109170 901029199	21/22 residual heat removal room coolers service water pipe replacement
Hope Creek	HC.MD-PM.BF-010(Q) HC.MD-PM.BF-008(Q)	Control rod drive removal, repair and replacement

The maintenance activities inspected were effective with respect to meeting the safety objectives of the maintenance program.

4.2 Surveillance Testing Inspection Activity

The inspectors performed detailed technical procedure reviews, witnessed in-progress surveillance testing, and reviewed completed surveillance packages. The inspectors verified that the surveillance tests were performed in accordance with Technical Specifications, approved procedures, and NRC regulations. These inspection activities were conducted in accordance with NRC inspection procedure 61726.

The following surveillance tests were reviewed, with portions witnessed by the inspector:

Unit	Procedure No.	Test
Salem 1	SP(O)-4.8.2.1, SP(O)-4.8.2.3.1	AC and DC electrical distribution
Hope Creek	HC.OP-ST.KJ-0008(Q)	Integrated Emergency Diesel Generator 18 Month Test

The surveillance testing activities inspected were effective with respect to meeting the safety objectives of the surveillance testing program.

4.3 Inspection Findings

4.3.1 Salem

A. Room Cooler Service Water (SW) Pipe Replacement

During system engineer walkdowns, several SW pipe spools were identified as being potentially degraded. The licensee repaired these deficiencies with in-kind pipe replacements for the Unit 2 residual heat removal (RHR) room coolers. Freeze sealing was required due to the leaks being outside the isolation valves in the SW system. Maintenance personnel, in conjunction with operations and system engineering, planned these repairs.

The inspector observed portions of the No. 21 and 22 RHR room cooler repairs including planning, freeze seal operations, welding, monitoring, and post-maintenance testing. The inspector noted that all the groups involved worked well together. Overall, the licensee was effective in conducting these repairs.

B. Condition Involving the Disabling of an Auxiliary Feed Water Pump Auto-Start Feature Due to Maintenance Error

On January 30, 1991, the licensee reported a condition that (1) would have prevented auto-start of Nos. 11 and 12 Motor Driven Auxiliary Feed Water Pumps (MDAFW) upon loss of both Steam Generator Feed Pumps (SGFP), as specified in TS Table 3.3-3, Item (f); and (2) would have caused the cross connect of DC Vital Buses "B" and "C" in certain unusual circumstances. The licensee identified the cause of this condition to be the result of personnel error during a maintenance activity involving the No. 11 SGFP on April 20, 1990.

At that time, a maintenance technician installed the wrong relay in the No. 11 SGFP stop valve position indicator light control circuit, i.e., a 125 VAC relay coil instead of the proper 125 VDC relay coil. There was no apparent immediate effect of this maintenance error.

However, on November 12, 1990, a jumper was installed to support No. 11 SGFP maintenance activities which required disabling of the SGFP control circuitry. A jumper was installed in conformance with TS in order to enable start of the MDAFW pumps on loss of the other SGFP. The combination of this jumper and the wrong relay (the AC type) in the No. 11 SGFP control circuit caused a connection to be established between the -125 VDC "C" Vital Bus and the +125 VDC "B" Vital Bus. Consequently, a current loop was completed through the ground fault detection circuitry of both the "B" and "C" batteries. The ground fault was identified on November 14, 1990, after DC Breaker No. 30 was closed to perform post maintenance testing of the No. 11 SGFP. The installation of the wrong relay coil (AC type) was discovered on November 15, 1990, during the investigation of this ground fault problem.

On December 20, 1990, the licensee concluded that the installation of the wrong relay would have prevented the auto-start of the MDAFW Pumps Nos. 11 and 12 upon loss of both SGFPs. Therefore, a determination was made that the circuit would not have performed its intended function, as required by TS 3.3.2.1 and the TS Applicability Table 3.3-3, Item 8(f), and was consequently reportable as a Licensee Event Report (LER 90-040-00) per 10CFR50.73.

In evaluating this event, the licensee determined that auto-start of the Nos. 11 and 12 MDAFW pumps on loss of SGFPs is not credited in the accident analysis, though listed in the TS, Table 3.3-3, Item (f); and that other MDAFW auto-start signals, such as loss of off-site power, safeguards sequence signal, or low-low Steam Generator water level were fully functional and operable in this period. Further, the licensee determined that while separation of the 125 VDC Buses was not maintained (as specified in the Updated Final Safety Analysis Report) in this particular situation (between November 12 and 14, 1990), it would not have resulted in common mode failure due to the high impedance between the batteries.

The licensee indicated that monthly surveillance testing of the logic as required by TS 4.3.2.1.1 would not identify this type of failure; but that actual functional verification, as required by TS 4.3.2.1.3 on a 18 month frequency, would have revealed this deficiency. Further, the licensee acknowledged that the determination of the issues resulting from this event were untimely, i.e., extending from November 15 to December 20, 1990.

Relative to corrective measures, the licensee immediately replaced the SGFP relay with the correct type and reviewed this event with the responsible maintenance personnel. Additionally, the licensee initiated examination of human factor concerns associated with relay identification, work practices, work order retest requirements, and documentation. This examination will be performed by a Human Performance Enhancement System (HPES) engineer. The HPES review will include work practice demonstrations, worker training evaluation, and root cause analysis. The expected completion date for this effort is June 28, 1991. Further, the Quality Assurance Department (QA) has initiated action to improve the timeliness of the process involved in LER determinations relative to identification and resolution of significant events. The QA review is expected to be completed by March 29, 1991.

In consideration of the licensee's self-identification of this item, the adequacy of the subsequent LER, and the establishment of corrective measures, this matter is considered as a licensee identified violation of TS Table 3.3-3, Item 8(f), and is not being cited since the criteria specified in Section V.G of the Enforcement Policy were satisfied (NON 50-272/91-01-01).

C. Failure To Perform Diesel Generator (DG) Operability Check

On December 6, 1990, the licensee identified that they had failed to test the 2A and 2B DGs after the 2C DG was taken out of service for maintenance. They discovered that the operability check required by Technical Specification (TS) 3.8.1.1.a to be performed once every eight hours, was missed due to personnel error. TS 3.0.3 was entered at 1:30 p.m. on December 6, 1990, upon discovering the missed requirement, and DGs 2A and 2B were subsequently tested successfully. TS 3.0.3 was exited at 1:48 p.m.

The inspector verified that adequate administrative controls were in place to direct the proper DG testing and agreed that this event was an isolated occurrence of personnel error. The individuals involved with this event were counseled by Station management. The licensee submitted Unit 2 Licensee Event Report 90-41 describing this event, and the inspector did not identify any inadequacies relative to the report. The inspector reviewed the LER including licensee corrective actions and determined them to be acceptable. The inspector also concluded that this licensee identified violation of TS 3.8.1.1.a is not being cited because the criteria specified in Section V.G. of the NRC Enforcement Policy were satisfied (NON 50-311/91-01-01).

4.3.2 Hope Creek

A. Control Rod Drive (CRD) Maintenance

During the refueling outage, the licensee removed 26 CRDs and replaced them with rebuilt drives. Contractor personnel were involved in removal, installation, flushing, and rebuild activities. The undervessel activities were performed using an automated system. NRC Inspection 50-354/90-22 reviewed licensee preparations, including training and radiation protection related activities.

The inspectors observed CRD maintenance activities including:

-- subpile room installation and removal,
-- maintenance room transfer and flushing,
-- rebuild room work,
-- CRD control room, and
-- main control room oversight.

Overall, CRD maintenance activities were well planned and efficiently executed. Contract personnel were effectively controlled.

During main control room observations, the inspector reviewed the licensee's use of Technical Specification (TS) 3.9.10.2. This TS allows multiple control rods to be removed from the core if the four fuel bundles are removed from an associated control rod cell. The licensee verified TS 3.9.10.2 items (a) through (f) by checking the following: reactor mode switch position, source range monitors, shutdown margin, control rods inserted, fuel assemblies removed, and no fuel loading operations. The reactor operator signed-off satisfactory completion on a check sheet maintained in the control room. A reactor engineer verified the shutdown margin in accordance with TS 3.1.1.

The inspector questioned the basis for this reactor engineer signoff and the basis for meeting the shutdown margin requirements of TS 3.1.1. The licensee responded by stating that a General Electric (GE) analysis (for a generic BWR) had concluded that the TS requirements were met. However, a more detailed Hope Creek specific analysis (i.e. end of cycle 3 with the actual control rod removal order) was performed by the PSE&G Fuels Department and verified by GE. That analysis (letter dated January 24, 1991) concluded shutdown margin requirements were met. The inspector discussed this item with licensee engineers and reviewed the analysis. The inspector had no further questions at this time.

B. Hope Creek Containment Local Leak Rate Testing (LLRT)

The resident inspector staff reviewed the results of LLRTs conducted in October 1987 for the residual heat removal (RHR) system testable check valves. This review was a follow-up of an inspection, documented in NRC Inspection Report 50-354/90-03, which was conducted in response to earlier concerns with the Hope Creek LLRT program.

The inspector reviewed the work orders and the LLRT data sheets related to the LLRTs conducted in the specified time frame for the RHR testable check valves. These documents revealed that RHR check valve, BC-V014, had failed the "As Found" Type C pneumatic test conducted on October 2, 1987. The inspector also identified several "Info Test" data sheets that documented testing of the valve following maintenance activities performed on the valve seat. The final "Info Test" data sheet contained a comment that the valve had not been cycled prior to testing, as required by LLRT regulations. The "As Left" data sheet, however, showed that the "As Left" test was conducted after the valve had been cycled once from the control room, was conducted on the same day as and subsequent to the final "Info Test", and was performed with satisfactory leakage results. As a result of these findings, the inspector concluded that the October 1987 LLRTs were satisfactorily performed.

As an additional check of the Hope Creek LLRT program, the inspector reviewed the current Hope Creek procedure M9-ILP-03H, "Type C Local Leak Rate Test-Hope Creek," and observed the performance of a LLRT during the plant outage. The Hope Creek procedure was found to comply with the LLRT regulations as put forth in 10CFR50, Appendix J,"Primary

Reactor Containment Leakage Testing for Water-Cooled Power Reactors," by containing the specific statements, "No repairs or tightening of leaking mechanical connections of the permanent installation, within the containment isolation boundaries, shall be attempted until the "As Found" test is completed and recorded," and also, "Following a containment isolation valve (CIV) "Rework" and prior to performing the "As Left" LLRT, the CIV shall be stroked one time." The inspector reviewed the paperwork which documented a failed LLRT performed during the latest plant outage and its subsequent correction, and no inadequacies were noted. The inspector also reviewed the paperwork for and observed the actual performance of the LLRT of the reactor auxiliary cooling system CIVs. The test was performed in a controlled and satisfactory manner, and the inspector noted good cooperation between the licensee and contractor personnel who performed the test. The inspector also noted that the paperwork used for planning, performing, and documenting the test was very well prepared and organized.

In conclusion, and based on the results of the inspection, the inspector determined that the Hope Creek LLRT program meets the regulatory requirements of 10CFR50, Appendix J, and that the program is well managed and satisfactorily implemented.

5. EMERGENCY PREPAREDNESS

5.1 Inspection Activity

The inspector reviewed PSE&G's conformance with 10CFR50.47 regarding implementation of the emergency plan and procedures. In addition, licensee event notifications and reporting requirements per 10CFR50.72 and 73 were reviewed.

5.2 Inspection Findings

No noteworthy findings were observed.

6. SECURITY

6.1 Inspection Activity

PSE&G's conformance with the security program was verified on a periodic basis, including the adequacy of staffing, entry control, alarm stations, and physical boundaries. These inspection activities were conducted in accordance with NRC inspection procedure 71707.

6.2 Inspection Findings

A. Increased Security Measures

Due to the war related activities in the Persian Gulf, the inspector questioned security organization personnel to ascertain whether any precautionary actions had been initiated. The inspector reviewed the actions and concluded that those actions taken and proposed by Security were proactive and appropriate. The inspector had no further questions at this time.

B. Wounded On-Duty Security Officer

On January 31, 1991 at 9:42 p.m., an on-duty fire watch member found a female contract security officer wounded by a single gun shot to the chest in the women's locker room near the Salem radiological control area (RCA) access point. The wound was apparently self-inflicted. The officer was transported by Medi-Vac helicopter to the Cooper Medical Center in Camden, New Jersey where she remained in critical condition for several days. The Lower Alloways Creek Police Department and Salem County Prosecutor's Office were notified and responded to the station to investigate the incident. One round had been fired from the officer's service weapon. A psychological services group also responded on-site to conduct post-stress and post-trauma debriefings with other employees. The licensee subsequently verified that plant security was not adversely impacted by this incident. The NRC Operations Center and the resident inspector were notified of the event at 10:53 p.m. The inspector reviewed the licensee's response to this incident and had no further questions at this time.

7. ENGINEERING/TECHNICAL SUPPORT

7.1 Salem

A. Engineering Review of NRC:RI Regional Administrator Tour Concerns

Several items were questioned during a tour by the NRC Region I Administrator on November 30, 1990. The following are the licensee's responses:

1. Unit 1 service water tray T-766 was noted as being deteriorated. The licensee determined that the transmitter associated with the tray was operable. The tray is scheduled for replacement during the upcoming outage when the piping in the area will be replaced. The specifications for trays require supports at eight foot intervals to ensure seismic integrity of the tubing. Although the tray is deteriorated, there are adequate supports for the tubing.

2. Two Unit 2 valves' (2SF108 and 2SF109) Chesterton packing appeared to have too many washers installed, and the inside diameter of the washers appears to be incorrect. The licensee determined that the associated specification sheets for Chesterton packing were found to be incorrect. The number of washers, their installation and diameters are also identified on these specification sheets. The licensee reviewed approximately 10% of similar valve specification sheets where Chesterton packing is used. This additional review noted approximately 14% of these specification sheets contained errors. This information was supplied to the Maintenance Department for their follow-up and correction. Work requests were written to correct valves 2SF108 and 2SF109.

3. Unit 2 safety injection pump room has exposed rebar in a column wall. The licensee determined that the opening in the wall is per design requirements. The rebar was not cut out during construction. The drawing detail does not require the rebar to be removed nor does it require the rebar to be exposed. Engineering and Plant Betterment was consulted and they determined that either is acceptable.

4. Craft personnel from the penetration seal team were drilling a grouted pipe sleeve on 100 foot elevation in the auxiliary building of Unit 2. The piping through this specific sleeve was a pipe used for heating water. The penetration seal team was contacted, and they suspended removing any sleeve grouting. Additionally, if a need does arise, administrative guidance will be provided within the design change which they are working to define precautions for craft personnel and inform the operating shift of the work.

5. A small water hammer was felt in the Unit 2 auxiliary feedwater piping at valve 22AF22. The system engineers were familiar with the noted water hammer. The water hammer was due to the collapsing of steam bubbles as they cool and leak by the installed check valves downstream of 22AF22. Since the magnitude of the water hammer in such circumstances is small, it was concluded that the water hammer does not detrimentally affect the system with regard to its safety function.

6. The remote manual operators in Unit 1 Service Water (SW) valve rooms were inoperable. The licensee concluded that the remote manual operators were not required to be operable. The valves are locked open such that the No. 13 containment fan coil unit may be supplied from either No. 11 or No. 12 nuclear SW header under normal operation. The system has installed check valves to prevent loss of SW for breaks in moderate energy line piping for the 16 inch and 20 inch SW lines. A break in the ten inch line between the check valves is not considered to be catastrophic (moderate energy line pipe). The loss of SW under this condition is not expected to be greater than pump capabilities and system needs. Additionally, the room is equipped with a flood alarm which provides the operators with indication of a break to which they could respond and enter the room and isolate. This evaluation was documented on a deficiency report with the appropriate 10CFR50.59 review. The remote operators will be replaced at the upcoming Unit 1 outage when the valve room piping is replaced.

B. Salem 1 and 2 Service Water System

1. <u>Scope</u>

On November 29, 1990, specialist inspectors from Region I performed an inspection of Salem service water system to investigate the following:

-- Three recent failures in service water piping at Salem;

-- Adequacy of licensee's corrective actions;

-- Structural integrity of the original piping in the degraded condition;

-- Replacement schedule of original cement lined and tar coated carbon steel piping;

-- Condition of new replaced piping;

-- Present on-going corrosion studies at Salem on AL-6XN and stainless steel piping in the service water environment;

-- Potential breach of containment due to leaking service water piping inside the containment; and

-- Adequacy of emergency diesel cooling in the event of service water piping failure.

2. <u>Details of Review</u>

Three recent failures (through-wall seepage) in the ASME Nuclear Class 3 service water piping of Unit 1 were as follows (see NRC Inspection 50-272 and 311/90-26):

-- On November 19, 1990, a one inch leak on a 12 inch diameter service water line in Service Water Bay No. 3 was identified.

-- On November 20, 1990, a service water leak was identified in the line providing cooling water to radiation monitor 1R13D.

-- On November 28, 1990, a weld on the service water line to No. 14 containment fan cooler unit (CFCU) outlet piping leaked. The leak was located at the weld joint of a 3/4 inch vent line connecting to the ten inch header.

The above failures were either in the cement lined carbon steel piping or adjacent to the piping weld. The failures were a result of wall degradation initially caused by microbiologically influenced corrosion (MIC) of the piping material in the service water environment.

The licensee's short-term corrective action was to repair the leaks by replacing the degraded piping with a new spool, using identical piping material. However, the long-term corrective action, which is currently in progress, is the replacement of the carbon steel piping with a high alloy austenitic stainless steel (AL-6XN) piping.

Since the service water system is a low pressure and a low energy system, catastrophic failure due to leaks in the system is not likely to occur. Approximately 40% of nuclear service water piping has been replaced in both units of Salem, and a total of 90%

of service water piping will be replaced by 1995. The material of the new piping is AL-6XN. This material has performed satisfactorily in the aggressive service water environment.

In addition to performing inspection of the new AL-6XN piping, the licensee has been subjecting welded corrosion specimens to the service water environment. The specimens are housed in fixtures which are positioned in test loops simulating various parameters including stagnant, flow, and various temperature conditions. The inspectors examined some of these specimens after 17 months of exposure. Except for minor oxidations, none of the specimens exhibited discernable corrosion, including those with intentionally introduced weld defects (unconsumed root insert).

There are flow elements in the supply and the return line to the CFCU. A leak in either line would create a differential in flow that exceeds a preset limit and would annunciate an alarm in the control room. The operator can remotely close the containment isolation valves of the affected line. Also, failure of service water piping inside the containment would cause the containment sump level to increase, warning the operator to identify the source of leakage. Each CFCU has a condensate collection system designed to identify a service water leak so that the unit can be promptly isolated. Hence, breach of containment is not anticipated with proper operator action.

Each emergency diesel is supplied with service water for jacket cooling from the two independent nuclear service water headers via separate supply lines. This will ensure that each diesel can be cooled even if there is a failure in one of the service water trains. However, the supply line leading to the diesel is a single line. Assuming a failure in the service water supply line to a diesel, and consequent loss of the diesel, there are two additional diesels available to perform the safety functions.

3. Conclusions

The recent service water system leaks have been numerous. However, structural integrity of the piping coupled with adequate flow to meet shutdown requirements appears to be acceptable. The licensee is continuing to proceed with service water pipe replacement with material resistant to the cause of identified leaks. In addition, the NRC Non-Destructive Examination (NDE) mobile facility was onsite during the period February 4-15, 1991, to review service water piping integrity.

C. Open Item Followup

(Closed) Violation 50-272/89-17-02: Failure to perform the appropriate safety review for a surveillance test procedure. The licensee responded to the violation via letter dated August 2, 1989. Similar examples were identified by the NRC as documented in Inspection Reports (IRs) 50-272 and 311/90-81 and 50-272 and 311/90-22. The NRC reviewed the licensee's corrective actions, which included the development of a new program that eliminated the use of a safety significant issue determination as a 10CFR50.59 screening factor. Based upon the inspector's previous review, which considered this issue resolved (IR 90-22), this item is closed.

D. Turbine-Driven Auxiliary Feed Water Pump Concerns

At the end of the last inspection report period, when operators started the Unit 1 No. 13 Auxiliary Feed Water (AFW) pump for the monthly pump test, the pump started, but the speed control was unstable. On January 4, 1991, when the monthly test was attempted with the Unit 2 No. 23 AFW pump, the pump started, but the speed fluctuated severely, and the pump was manually tripped from the control room. The Salem I&C department vented the Woodward governor and added oil, and the test was eventually satisfactorily run, although speed oscillations still occurred.

Due to the similarity of the problems encountered with the testing of the two turbine-driven AFW pumps and their potentially high safety significance, the resident inspector discussed the matter with the Salem AFW system engineer. The inspector learned that the Salem Technical Department had conducted an investigation of the AFW pump problems, and the inspector was provided with a copy of the report documenting the results of the investigation. The report attributed the cause of the No. 13 pump speed instability to a lock nut falling off and binding the governor linkage, and the speed oscillations of the No. 23 pump to the improper positioning of the governor compensation needle valve. The report also discussed separate concerns regarding the sensitivity of the overspeed trip mechanism of the pumps, the sizing of condensate drain orifices, and the Salem application of NRC Information Notice No. 88-09, which dealt with the reduced reliability of steam driven AFW pumps caused by Woodward governors.

The inspector concluded that the Technical Department investigation had been effective in determining the causes of the recent AFW pump problems and was comprehensive in its consideration of other factors affecting the pumps. The timeliness with which the Salem system engineers pursued the AFW pump issue was notable. However, the inspector also concluded that these two most recent events involving the AFW pumps might have been avoided. There is a recurring task in the Salem preventive maintenance program to inspect the linkages for worn or loose parts, and there was no explanation as to why the loose lock nut on the No. 13 pump governor linkage was not detected. Also, the problem with the No. 23 pump needle valve position was readily resolved by a vendor representative with a method that had long been available to the licensee. The resident staff will continue to monitor turbine-driven AFW pump performance.

E. Degraded Containment Cooling Capability

On February 9, 1991, the licensee reported to the NRC that Unit 1 did not meet the UFSAR specifications for containment heat removal.

The containment fan cooling system is an engineered safeguards system that consists of five containment fan coil units (CFCU). During accident conditions, it functions with the two independent trains of the containment spray (CS) system to remove heat from the containment in order to prevent pressure and temperature from exceeding design limits. Salem can meet the UFSAR specifications by one of the following:

1) All five CFCUs; or
2) Both CS trains; or
3) Three of five CFCUs and one CS train.

Prior to entering the Unit 1 ninth refueling outage on February 9, 1991, the licensee conducted heat transfer capability testing for the CFCUs per their documented commitments to NRC Generic Letter No. 89-13, "Service Water Problems Affecting Safety-Related Equipment." Salem committed to test/clean their CFCUs as follows: Unit 1 during its ninth refueling outage and Unit 2 during its sixth refueling outage (November 1991).

Salem UFSAR Section 6.2.2.2 states that each of the five CFCUs is capable of removing 81 million BTU/hr from the containment atmosphere at post-accident design conditions. Following the recent CFCU testing, the licensee determined that three of the five CFCUs were less than 81 million BTU/hr. The initial Unit 1 heat transfer testing results are as follows:

CFCU No.	BTU/hr (Million)
11	83.6
12	62.1
13	42.2
14	50.1
15	85.4

None of the five Unit 1 CFCUs had been periodically inspected, cleaned or tested. However, the licensee cleaned the No. 14 CFCU following its test failure by removing a small amount of debris (approximately 1/2 bucket) from the CFCU waterboxes (service water). The subsequent heat capacity test indicated an increased heat transfer rate of 72.5 million BTU/hr from 50.1 million BTU/hr, but still less than the design value.

Since Unit 2 was operating at full power, the inspector questioned the status of the Unit 2 CFCUs. The licensee performed a historical review for the Unit 2 CFCUs and determined the following:

-- Two CFCUs (Nos. 24 and 25) were hydrolazed during the fifth refueling outage (Spring 1990).

-- No. 24 CFCU was tested satisfactorily following hydrolazing.

-- Three CFCUs (Nos. 21, 22, 23) were inspected and cleaned (debris removal from waterboxes) during the fourth refueling outage (Winter 1988).

Through discussions with the licensee, the inspector ascertained that the Unit 1 CFCU coolers (tubes) were replaced in 1982 and the Unit 2 coolers were replaced in 1983.

Based on the above, the licensee concluded that the Unit 2 CFCUs are acceptable. However, they intend to aggressively inspect, clean as necessary, and test all five CFCUs per Generic Letter 89-13. This will begin immediately and continue for about the next two to three weeks.

The inspector concluded that the licensee's actions to date have been in conformance with their commitments to the Generic Letter, and the reporting requirements of 10CFR50.72 have been properly implemented. The inspector will continue to monitor the licensee's inspection, cleaning and testing activities on both units. Pending review of the above activities, this item is unresolved (50-272/90-01-03).

7.2 Hope Creek

A. Reactor Recirculation Instrumentation Line Leakage

On November 4, 1990, Hope Creek automatically shut down after a main steam isolation valve closed when its associated instrument gas line sheared off. Subsequent to the shutdown, the licensee entered the drywell to determine the source of an unidentified leak of approximately 1.7 gpm. A leak was discovered at a weld on a "B" loop recirculation instrument line as discussed in Revision 1 to Licensee Event Report (LER) 90-25. Analysis of the weld indicated that the root cause of the failure was vibration induced fatigue, with a stress concentration at the weld root and a non-symmetrically positioned pipe fit-up contributing to crack initiation. Design changes developed as a result of previous similar events (LER 89-26 describes the most recent one), originally intended for installation during the third refueling outage, were instead implemented prior to restart of the unit. The changes provided for monitoring of recirculation instrument line vibration and adding or modifying a number of pipe supports. During the period of reactor power operation prior to shutdown for the outage on December 26, 1990, drywell unidentified leakage remained constant at about 0.65 gpm.

The inspector observed the licensee's activities related to the drywell unidentified leak rate from the time an increasing leak rate was noted in September 1990 until the outage shutdown. The inspector concluded that Operations personnel had conducted an aggressive investigation to determine the source of the leakage and had in place additional actions which would be taken if the leak rate increased. Although the investigation could not pinpoint the exact location of the leak, a number of factors led the licensee to conclude that the leak was in the area of the "B" recirculation pump. The licensee's actions and aggressive inquiry reflected a conservative safety perspective. The inspector did not note any inadequacies in this LER.

B. Reactor Recirculation System Piping Weld Indications

On January 3, 1991, during the scheduled Section XI Inservice Inspection (ISI) by dye penetrant (PT) examination, two linear indications were found in the crown of weld 1-BB-28VCA-013-6, which was located in the "A" reactor recirculation loop discharge at the 28 inch to 12 inch reducer tee. Three additional 28 inch welds were then examined by PT and weld 1-BB-28VCA-014-6 (on the "B" loop at the same location as on the "A" loop) was found with two linear indications. All the remaining 28 inch welds in both loops were then examined with no unacceptable conditions determined. The cracks were then excavated to the maximum depth (7/16 inch) and weld repaired. Metallurgical and chemical analyses of a boat sample taken from one of the welds showed that the indications were most likely hot cracks (or hot tears) formed during the welding process. Region-based inspectors observed and evaluated the licensee's testing techniques, repairs and analyses; their findings were described in NRC Inspection Reports 50-354/90-24 and 91-02. The four indications were outside the area of the welds normally examined for intergranular stress corrosion cracking (IGSCC) by ultrasonic test (UT) methodology. Consequently, a modified UT technique was developed to examine the area of a weld where such defects could occur. Five 28 inch and three 12 inch welds were examined using this technique; no unacceptable conditions were found. The inspector noted that the licensee's activities relating to investigation, repair and non-destructive testing of the reactor recirculation pipe 28 inch welds appeared thorough and well coordinated, with minimal impact on the outage overall.

8. SAFETY ASSESSMENT/QUALITY VERIFICATION

8.1 Salem

A. Pressurized Water Reactor (PWR) Moderator Dilution (TI 2515/94)

The NRC was required to perform inspections at PWRs to ensure the licensee had completed changes to administrative controls or implemented plant modifications in response to DOR Information Memorandum No. 7, "PWR Moderator Dilution" dated October 4, 1977 in accordance with TI 2515/94. This was reviewed for Salem Unit 1, and by letter dated February 1, 1978, the licensee concluded that no corrective action was necessary. Additional information was supplied by the licensee by letters dated April 2, 1981, October 5, 1981, and February 3, 1982. By letter dated April 29, 1982, the NRC agreed with PSE&G's assessment that no corrective action was necessary.

Therefore, the NRC has determined that no follow-up verification is needed for the subject issue, and TI 2515/94 is not applicable to Salem Unit 1. Because Salem Unit 2 was licensed after the DOR letter and because it has essentially the same configuration as Salem Unit 1, TI 2515/94 is also not applicable to Salem Unit 2. Therefore, TI 2515/94 is considered closed for both Salem Units 1 and 2.

B. Shutdown Margin Monitor

Both Salem units have a shutdown margin monitor system. This is separate from the nuclear instrumentation system used for reactor power indication and reactor protection. The shutdown margin monitor system consists of two channels ("C" and "D") of Gamma-metrics fission chambers that measure neutron flux from the source range to the power range (ten decades). The shutdown margin monitor is a Class 1E system designed for a harsh environment as required by NRC Regulatory Guide 1.97 and 10CFR50.49. This system was installed in 1985. Control room indication for this system includes a source range and power range (channels "C" and "D") meter.

On February 6, 1991, during a routine plant tour, the inspector noted that Unit 2 channel "C" power range was being investigated by maintenance technicians. Upon further review, the inspector noted that this channel (2XA6921) had been out of service since July 16, 1990 (Work Order Nos. 900716150 and 900730005), apparently due to failed electronic components and unavailability of spare parts.

The inspector reviewed Technical Specifications (TS) and noted that this shutdown margin monitor system had no TS operability requirements. The inspector questioned licensed operators and noted that they were knowledgeable regarding the system. The inspector also questioned licensing personnel and determined that there were no actions in progress nor planned to include the shutdown margin monitor system in TS.

On February 9, 1991, the licensee shutdown Unit 1 for its ninth refueling outage. The inspector noted that shutdown margin monitor channel "D" tracked with all channels of nuclear instrumentation. However, channel "C" did not. The inspector questioned the licensee regarding this matter. Subsequent licensee review indicated that this channel had failed and the appropriate work orders were initiated.

The Unit 1 and 2 shutdown margin monitor system availability and lack of TS requirements are considered unresolved (UNR 50-272/91-01-02). This matter will be reviewed with the licensee and NRC's Office of Nuclear Reactor Regulation to determine the advisability of establishing a TS operability requirement.

C. Open Item Followup

(Closed) Unresolved Item 50-272/89-16-04: Feedwater Regulating Valve (FRV) closure time criteria are inconsistent between Units 1 and 2 Technical Specifications (TS). The licensee submitted a TS amendment change request to the NRC by letter dated April 2, 1990. NRC review of the request is in process. Based upon licensee submittal of the change request, to revise and make consistent the associated Unit 1 and 2 TS, this item is closed.

8.2 Hope Creek

Refueling Outage Activities

Overall, the licensee effectively conducted and managed the Hope Creek refueling outage activities. Good performance was noted during inspector observations of core defueling, core refueling, fuel sipping, and control rod drive maintenance activities. Periodic outage meetings were noted as being effective in communicating and coordinating refueling outage activities. Corporate, plant and departmental management presence was noted during periodic outage meetings, in the control room and in the plant. The Radiation Protection and Chemistry Manager was noted to be making periodic drywell entries and inspections.

However, there were some weaknesses noted during the refueling outage. A relative high number of personnel contaminations occurred primarily due to poor radiation protection practices. These practices included face touching while wearing protective clothing and improper removal of this clothing. These poor worker practices were confirmed by the inspectors during in-plant observations. Licensee actions to address these deficiencies were somewhat effective. Another weakness was noted relative to plant housekeeping near the end of the outage. Inspectors noted a large accumulation of material/trash in numerous plant areas. Licensee management also noted this accumulation; and they initiated actions to clean up these plant areas.

8.3 Common

A. Status of Labor Contracts

The inspector reviewed the status of labor contracts for PSE&G bargaining and union personnel. The inspector determined that Salem and Hope Creek non-supervisory workers in the Operations, Maintenance, and Radiation Protection Organizations are affiliated with IBEW, Local 1576. They currently have a three-year contract which expires April 30, 1992. The non-supervisory workers in the Artificial Island Security Organization are affiliated with Security Officers, Police and Guards Union, Local 99. They currently have a three-year contract which expires December 10, 1993. No concerns were identified.

9. LICENSEE EVENT REPORTS (LER), PERIODIC AND SPECIAL REPORTS, AND OPEN ITEM FOLLOWUP

9.1 LERs and Reports

PSE&G submitted the following licensee event reports, and special and periodic reports, which were reviewed for accuracy and evaluation adequacy.

-- Salem and Hope Creek Monthly Operating Reports for December 1990.
-- Hope Creek Core Operating Limits for Cycle Four, dated January 24, 1991

No unacceptable conditions were noted.

Salem LERs

Unit 1

LER 90-26-04 concerns service water system leaks that were previously reported to the NRC. These events were reviewed in a previous inspection report (50-272/90-26). No inadequacies were noted relative to this LER.

LER 90-39 concerns a radiation monitoring system actuation causing a containment ventilation isolation on December 14, 1990. This event was reviewed in NRC Inspection 50-272/90-26. No inadequacies were noted relative to this LER.

LER 90-40 (See section 4.3.1.B)

Unit 2

LER 90-25-01 is a revised report for a condition affecting the main steam vent valve control panels. (See NRC Inspection 50-272 and 311/90-27 for this item).

LER 90-41 (See section 4.3.1.C)

LER 90-42 describes a TS 3.0.3 entry that was made on December 20, 1990, due to the No. 21 service water header becoming inoperable when a through-wall leak developed on the inlet to a component cooling pump room cooler. (This event was previously detailed in NRC Inspection 50-311/90-26).

LER 90-43 concerns a TS 3.0.3 entry that occurred at 1:54 a.m. on December 20, 1990, due to a loss of all control room analog rod position indication (ARPI). The licensee determined the cause to be a control room recorder that shorted a wire to ground resulting in an electrical transient that tripped the ARPI feeder circuit breaker. The licensee repaired the recorder, reset the ARPI circuit breaker and returned rod position to normal. TS 3.0.3 was exited at 2:45 a.m. The inspector reviewed the LER and had no questions at this time.

LER 90-44 concerns radiation monitoring system (RMS) containment ventilation isolations that occurred on December 23 and 24, 1990 and on January 14, 1991. The suspect RMS channels (2R12A and 2R41C) were instrumented with strip chart recorders. The licensee determined the RMS failure to be loose electrical connection in 2R12A. The connections were repaired and the RMS channel was returned to service. The licensee is pursuing long term RMS design modifications.

Hope Creek

LER 90-25 Revision 1 (See section 7.2.A)

LER 90-32 discusses a primary containment isolation system (PCIS) actuation on December 11, 1990, which was noted in Section 4.3.2.B of NRC Inspection Report 50-354/90-21. The licensee determined that several errors by supervisory personnel were the primary cause of the event. Also, a human factors issue was highlighted when precautionary information was not clearly displayed on the work order. Corrective actions included counseling the individuals involved and revising the work order to include the appropriate precaution in a highly visible location on the first page. The inspector reviewed this issue with Operations management, noting that this event occurred despite specific precautions and related verifications in the surveillance procedure. The licensee was pursuing additional measures (procedure enhancements) when the report period ended.

LER 90-33 concerns a loss of power to the "A" Reactor Protection System (RPS) bus and the resultant half-scram and isolation of the Reactor Water Cleanup (RWCU) system due to a spurious trip of the alternate power supply electrical protection assembly (EPA) which was powering the "A" RPS bus while its normal power supply was out of service for maintenance. The trip was initiated by a faulty logic card in the EPA circuitry. The licensee noted that a number of spurious EPA trips had occurred previously. The most recent trip was documented in LER 90-07, as discussed in Inspection Report 50-354/90-10. The licensee's corrective action was to initiate a design change to the EPA circuitry, enhancing logic card performance by installing an upgrade kit as recommended by the EPA vendor, General Electric, in their Service Information Letter (SIL) 496, Revision 1. The upgrade kits are scheduled to be received in the second quarter of 1991, with installation complete by the end of 1991. The licensee's actions to enhance EPA performance appear appropriate and timely given the scheduled delivery date. No inadequacies were noted in this LER.

LER 90-34 deals with an automatic start of the Filtration, Recirculation and Ventilation System (FRVS) "F" fan on December 24, 1990, and "E" fan on January 7, 1991. The cause of these events - an automatic start circuitry design deficiency - was identical to other recent FRVS actuations (see LERs 90-06 and 90-23). In addition to expediting the design change to install a time delay in the auto-start circuitry committed to in LER 90-23, the licensee is investigating the feasibility of providing auto-start annunciation for fans "E" and "F" and will modify all FRVS unit surveillance procedures to require blowing down associated instrument tubing following a run of the fan unit.

LER 90-35 concerns a through-wall service water pipe leak which was reviewed in Inspection Report 50-354/90-21. The licensee determined that the leak was caused by a flaw in the pipe internal epoxy coating which allowed corrosion to begin and subsequently lead to pipe erosion. As corrective actions, the licensee visually inspected selected sections of the safety related piping and replaced the defective pipe. Additionally, the inspector noted that large portions of the "A" service water loop piping were to be replaced during the next refueling outage while most of the "B" loop had been replaced during the current outage. No inadequacies were noted in this LER.

9.2 Open Items

The following previous inspection items were followed up during this inspection and are tabulated below for cross reference purposes.

Site	Report Section	Status
Salem		
TI 2515/94	8.1.A	Closed
272/89-22-01	2.2.1.F	Closed
272/89-17-02	7.1.C	Closed
272/89-16-04	8.1.C	Closed
272/89-26-02	2.2.1.C	Open
Hope Creek		
None		

10. EXIT INTERVIEWS/MEETINGS

10.1 Resident Exit Meeting

The inspectors met with Mr. S. LaBruna and Mr. J. Hagan and other PSE&G personnel periodically and at the end of the inspection report period to summarize the scope and findings of their inspection activities.

Based on Region I review and discussions with PSE&G, it was determined that this report does not contain information subject to 10 CFR 2 restrictions.

10.2 Specialist Entrance and Exit Meetings

Date(s)	Subject	Inspection Report No.	Reporting Inspector
1/14-17/91	Emergency Operating Procedures Followup	272; 311/91-02	Silk
1/16-17/91	Chemistry	272; 311/91-03	Kaplan
2/4-15/91	Non Destructive Examination Van Service Water System)	272; 311/91-04	Modes

Date(s)	Subject	Inspection Report No.	Reporting Inspector
1/7-11/91	Inservice Inspection	354/91-02	McBrearty
1/14-18/91	Radiation Protection	354/91-03	Chawaga