U. S. NUCLEAR REGULATORY COMMISSION

REGION I

Report Nos.	50-272/90-22 50-311/90-22 50-354/90-16
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:	August 16, 1990 - October 1, 1990
Inspectors:	T. P. Johnson, Senior Resident Inspector S. M. Pindale, Resident Inspector S. T. Barr, Resident Inspector H. K. Lathrop, Resident Inspector A. E. Lopez, Reactor Engineer R. S. Barkley, Project Engineer F. I. Young, Senior Resident Inspector, Three Mile Island

Approved: P. D. Kaufman for P. D. Swetland, Chief, Projects Section 2A — 10/31/90 Date

Inspection Summary: Inspection 50-272/90-22; 50-311/90-22; 50-354/90-16 on August 16, 1990 - October 1, 1990

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

Results: The inspectors identified one violation with multiple examples and five non-cited violations: three for the Salem Station and two for the Hope Creek Station. An executive summary follows.

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EXECUTIVE SUMMARY

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August 16, 1990 - October 1, 1990

OPERATIONS (Modules 71707, 93702, TI 2515/101)

Salem: The units were operated in a safe manner. Three unplanned reactor trips (two on Unit 1 and one on Unit 2) occurred due to: (1) inadequate preventive maintenance on non-safety related breaker cubicles; (2) multiple equipment failure; and (3) development of an inadequate troubleshooting plan. Licensee followup for these reactor trips was thorough. An instance of failure to follow procedural guidance and administrative controls, and several instances of poor communications resulted in other events (ESF actuations, AFW tank overflow, unauthorized release of tags). The licensee effectively conducted midloop operations at Unit 1 during the replacement of a reactor coolant pump motor. A personnel error and a contributing procedure weakness resulted in a minor spill in the Unit 1 containment. Two non-cited violations were identified: one was for failure to follow a turbine test procedure that resulted in a Unit 1 reactor trip, and one was failure to follow the tagging administrative procedure for the number 22 containment fan coil unit.

Hope Creek: The unit was operated in a safe manner. Licensee actions for high moisture content in the high pressure coolant injection system lube oil system were adequate. An increase in drywell unidentified leak rate and an apparent fuel pin leak were aggressively pursued by the licensee with an appropriate level of safety perspective.

RADIOLOGICAL CONTROLS (Modules 71707, 93702)

Salem: No noteworthy findings were identified.

Hope Creek: No noteworthy findings were identified.

MAINTENANCE/SURVEILLANCE (Modules 61726, 62703, 73755, 73756, 92702)

Salem: NRC observed maintenance and surveillance activities were effectively controlled. Failure to perform 10CFR50.59 and ASME Section XI evaluations for degraded number 22 boric acid transfer pump flow rate is a violation. Licensee corrective actions were evaluated to be satisfactory and no response is required. Containment liner corrosion issues were adequately addressed by the licensee. A licensee QA inspector properly identified, evaluated and reported a potential safety concern that resulted from poor intra and interdepartmental communications regarding a reactor trip breaker surveillance test. Another example of poor communication occurred during followup to a safeguards equipment control actuation. An error in licensed operator judgement resulted in late declaration of auxiliary feedwater pump inoperability. A surveillance test procedure weakness resulted in an inadvertent main steam line isolation. A non-cited, licensee identified violation regarding TS surveillance testing frequency error for the solid state protection system was identified. An unresolved item regarding inservice testing vibration markings remains open due to ineffective corrective actions.

Hope Creek: NRC observed maintenance and surveillance activities were effectively controlled. Failure to follow a surveillance procedure resulted in an inadvertent isolation of the reactor core isolation cooling system. This is a non-cited, licensee identified violation. A personnel error resulted in a failure to re-baseline the service water spray wash pump after maintenance and is a non-cited, licensee identified violation.

Common: Maintenance troubleshooting was determined to be effectively controlled. However, a potential programmatic weakness regarding the control of operations troubleshooting activities was identified.

EMERGENCY PREPAREDNESS (Module 71707)

No noteworthy findings were identified.

SECURITY (Module 71707, 93702)

No noteworthy findings were identified.

ENGINEERING/TECHNICAL SUPPORT (Modules 37828, 41400, 71707, TI 2515/65)

TMI Action Plan (TAP) Review: Salem (TAP item II.B.1.2, 3) Unit 1 and Unit 2 reactor vessel head vents and Hope Creek control room habitability (TAP item III.D.3.4.2) are closed.

Salem: A review of the systems engineer training program did not reveal any deficiencies. Safety equipment room cooler operability associated with licensee TS interpretation (unresolved item) remains open pending completion of licensee actions. A previous violation associated with the failure to perform a safety evaluation for the seismic impact of a reactivity computer is closed. An unresolved item associated with charging pump flow orifices being installed backwards is closed.

Hope Creek: The licensee identified and properly handled a design deficiency associated with temperature limits of the ultimate heat sink (Delaware River).

SAFETY ASSESSMENT/ASSURANCE OF QUALITY (Modules 30703, 71707, 90714, 92700, 92702, 92703, 92720)

Salem: One NRC Regional Waiver of Compliance was processed for Salem to allow replacement of the Unit 2 number 22 containment fan coil unit. This submittal was adequate. Reactor protection system setpoint changes of steam generator level and steam pressure were adequately handled by the licensee. Failure to maintain independence of station qualified reviewers, failure to perform a safety evaluation for a non-ASME code repair (Belzona R) and failure to properly handle significant safety issues are further examples of violations of 10CFR50.59.

Hope Creek: Two NRC Regional Waivers of Compliance were processed for Hope Creek: One associated with inadequate diesel generator fuel oil sample results and one associated with the replacement of the "A" safety auxiliaries cooling system (SACS) pump. The first submittal was adequate. However, weaknesses were identified relative to the completeness of technical information and safety basis for the second (SACS) submittal. Two personnel errors occurred during the period; one by maintenance personnel during surveillance and one by operations personnel during equipment post-maintenance testing per ASME Section XI.

DETAILS

1. SUMMARY OF OPERATIONS

1.1 Salem Unit 1

Salem Unit 1 began the report period in Mode 3 (Hot Standby) and preparing for unit startup following resolution of main steam isolation valve (MSIV) concerns. During startup activities, the reactor automatically tripped on August 17, 1990 after the No. 14 reactor coolant pump (RCP) lost electrical power during 4 kV non-vital auxiliary power transformer feeder breaker switching. The unit was subsequently shutdown to Mode 5 (Cold Shutdown) to replace the No. 14 RCP motor. The unit was returned to service on September 7, 1990, and operated until September 10, 1990, when an automatic reactor trip occurred while preparing to isolate a high pressure turbine sensing line leak. Power operation resumed on September 12, 1990, and continued until the end of the inspection period.

1.2 Salem Unit 2

Salem Unit 2 began the report period in Mode 3 (Hot Standby) and preparing for unit startup following resolution of MSIV concerns. The unit was placed in service on August 20, 1990, and power operation continued until September 4, 1990, when the unit tripped automatically due to a secondary system transient caused by equipment failures. Power operation resumed on September 8, 1990, and continued until the end of the inspection period.

1.3 Hope Creek

The Hope Creek unit remained operational during the report period. Several power reductions occurred to conduct maintenance and testing activities. During the period, the drywell unidentified leak rate increased, and a small fuel pin leak was noted.

1.4 Organizational Changes

On September 24, 1990, PSE&G announced the following organization changes effective October 1, 1990: Lynn Miller, General Manager, Salem Operations, will assume a new position of General Manager, Nuclear Operations Support. His responsibilities will include management of the Salem materiel and procedure upgrade projects. He will also assume interim management responsibility for nuclear services, procurement and material control, and reliability and assessment. Stanley LaBruna, Vice President, Nuclear Operations, will assume responsibility as Acting General Manager, Salem Operations. Also, Chuck Johnson has been assigned as acting General Manager, Hope Creek Operations since September 4, 1990, while Joe Hagan attends management training until December 1990.

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 Limiting Conditions for Operation, and review of facility records. These inspection activities were conducted in accordance with NRC inspection procedures 60710, 71707, 71711 and 93702. The inspectors performed normal and back shift inspection (597 hours), including deep backshift inspection as follows:

Unit	Inspection Hours	Dates
Hope Creek	8:00 a.m. - 12:00 noon	September 16, 1990
	6:00 a.m. - 10:00 a.m.	September 22, 1990

2.2 Inspection Findings and Significant Plant Events

2.2.1 Salem

A. Unit 1 Reactor Trip on August 17, 1990

A Unit 1 reactor trip from 25% power occurred due to 14 steam generator (SG) low-low water level on August 17, 1990, at 6:12 a.m. The trip occurred during 4KV non-vital auxiliary power transformer feeder breaker switching. An interlock, cell switch 52IS, prevented the feeder breaker from properly closing during a group bus transfer. This resulted in a loss of power to the No. 14 reactor coolant pump (RCP) motor. A resultant level shrink in the No. 14 SG due to the steam pressure increase caused the SG low level condition. Prior to the group bus transfer of the non-safety related distribution system, the shift electrician had verified breaker cell switch and fuse continuity to ensure the breaker was fully racked in (interlock switch made up). However, post trip inspection of the breaker compartment found a loose and binding condition in the cell switch linkage that could have caused intermittent continuity during electrical group bus swapping. The licensee reported the event appropriately to the NRC Operations Center. A Significant Event Response Team (SERT) was initiated by the licensee.

After post-trip review, and in preparation for reactor restart, the No. 14 RCP was placed in service at 5:15 p.m. on August 17, 1990. Subsequently, at 7:13 p.m., the RCP tripped on a phase to ground fault condition. The licensee meggered the motor and found a motor winding failure. The unit proceeded to Mode 5 (Cold Shutdown) to replace the No. 14 RCP motor.

At about 6:45 a.m. on August 17, 1990, the inspector reviewed post trip conditions in the control room including emergency operating procedure implementation, selected chart recorder traces, operator performance and control room logs. Operators were interviewed, including the reactor and senior reactor licensed personnel. The completed AD-16, "Post Reactor Trip Review", was also reviewed. The inspector also discussed the trip with operations and plant management personnel.

The inspector examined the failed breaker cell switch and associated cubicle in the field. The system engineer was questioned regarding breaker and cubicle operation, utilizing electrical prints and schematics. The inspector noted that the system engineer was knowledgeable of breaker operation and of the probable failure mechanism.

The inspector also discussed the breaker failure with the Maintenance Department manager. The manager acknowledged that there had been three similar breaker failures in the past three years. A five year preventive maintenance (PM) task on breakers is performed by the vendor. However, there is no recurring task or PM to check the breaker cubicle cell switch (52IS) and the racking mechanism alignment. A reliability centered maintenance recommendation was made in March 1990 to check the cell switch/racking mechanism in each 4KV breaker every 36 months. This PM activity was scheduled for Unit 2 during the fifth refueling outage (March - May 1990). However, tagging boundary difficulties prevented this PM activity from occurring. Unit 1 is currently scheduled for this PM activity in January - February 1991.

The inspector also reviewed the related Unit 1 LER 90-29 dated September 12, 1990 and SERT report dated August 23, 1990. The licensee concluded that the root cause of the reactor trip was mechanical failure due to inadequate preventive maintenance on the non-safety related breaker cubicle (e.g., cell switch). Licensee corrective actions included: inspecting and repairing similar breaker cubicles, verifying operability of breakers and cell switches, and revising maintenance procedure M3H to include a recurring PM task. The inspector concluded that the licensee's review of the event and corrective actions were adequate.

B. Unit 2 Reactor Trip on September 4, 1990

On September 4, 1990, Unit 2 automatically tripped from 60% power due to high-high water level in the No. 24 steam generator (SG). While operating at 100% power, an operator noted a control room indication that one of two operating SG feedwater pumps had tripped. The feedwater regulating valves (FRVs) for each of the four SGs went full open to maintain programmed water level. The operator immediately initiated a main turbine load reduction to 60% power and took manual control of all four FRVs, per abnormal operating procedures. SG levels decreased to 24% narrow range (normal is 44%), and then began to increase. High-high SG level turbine and reactor trips occurred before the operator could manually close the associated FRV for the No. 24 SG. A large level error caused by the low SG levels, resulted in slow response of the FRV controllers to the manual close demand signal. Additionally, when the FRVs were placed in manual, the No. 21 FRV operated abnormally and went fully closed, thereby increasing feedwater flow through the remaining three FRVs. The licensee reported the reactor trip to the NRC via the Emergency Notification System in accordance with 10CFR50.72 reporting requirements.

Licensee followup of the unit trip identified that the No. 21 steam generator feedwater pump (SGFP) tripped automatically due to low suction pressure. There are two automatic low suction pressure trips associated with the SGFPs: 1) 215 psig with a three second time delay, and 2) 190 psig instantaneous trip. The licensee identified two equipment problems that together resulted in the plant transient, namely the miscalibration of the No 21 SGFP suction pressure switch and a heater drain pump discharge control valve diaphragm failure. The failure of the No. 21 SG FRV controller also resulted in ineffective level control.

A post-trip calibration of the No. 21 SGFP pressure switch identified that the 215 psig setpoint was actually set high (an equivalent setpoint of 329 psig due to sensing line configuration and pressure switch location). SGFP suction pressure prior to the transient was equivalent to 370 psig as indicated in the control room. Therefore, only a 41 psig suction pressure reduction would result in the time delayed No. 21 SGFP trip (370 to 329 psig).

The licensee also determined that the No. 23 heater drain pump discharge control valve (HD15) failed during the transient. Specifically, the valve's diaphragm ruptured, and the valve went fully closed, creating a SGFP suction pressure reduction. That pressure reduction, in combination with the pressure switch increased trip setting, resulted in the SGFP low suction pressure trip.

For about one hour prior to the trip, the licensee identified additional flow oscillations (approximately 2000 gpm) on the outlet of the full flow condensate polishing system. These oscillations were unexplained and did not appear to directly impact operation of the secondary system. Nonetheless, the licensee initiated and is continuing efforts to identify the cause of the oscillations.

Prior to the transient, one (of six) condenser circulator (No. 21B) was taken out of service for cleaning and maintenance. Water level in the associated condenser hotwell was reduced, and temperature was elevated due to the absence of circulating water in that waterbox. The inspector noted that the above conditions may have contributed to the trip by creating flashing conditions downstream of the condensate pumps and resulting in reduced pressure at the SGFP suction. The licensee was also evaluating those conditions for future corrective actions.

During followup of the trip, the inspector reviewed the associated abnormal operating procedures (AOPs). AOP-COND-2, "Loss of Circulating Water and/or Condenser Vacuum", specifies procedure entry when one or more circulating pumps trip or are taken out of service. The inspector determined that the AOP was not entered by plant operators when the single circulating pump was initially taken out of service. Discussions with unit operators and Operations management indicated that since circulators are frequently taken out of service for both preventive and corrective activities, and this is considered to be a routine activity, the AOP is not entered. However, the operators closely monitored condenser conditions. The inspector reviewed AOP-COND-2 and determined that only routine actions are directed when only one circulator is out of service. Additional actions are directed by the AOP only when two circulating water pumps are out of service on the same condenser shell. Therefore, entry into the AOP under the specific conditions that existed on the day of the trip would not have resulted in significant operator response. The inspector discussed the practice of not entering AOPs, although specific entry conditions were met, with licensee management. Management acknowledged the inspectors' concern and committed to evaluate AOP usage and implement corrective actions.

A Station Operations Review Committee (SORC) meeting was conducted on September 5, 1990, to review the post trip data and plant response. The inspector attended the meeting. Plant startup was authorized with the following conditions and short-term corrective actions: 1) calibrate the SGFP suction devices, 2) evaluate AOP- COND-2 to develop procedure changes to address conditions and actions specific to operating with one circulator out of service, 3) conduct training sessions with the appropriate personnel, and 4) complete all necessary component repairs. Longer term recommendations included: 1) resolve condenser polisher flow discrepancies, and 2) evaluate the condenser hotwell dynamics and the impact on secondary plant components. A significant event response team (SERT) was formed and independently reviewed the event.

A unit startup subsequently commenced and the reactor was made critical on September 6, 1990. The inspector concluded that the licensee's review and followup of this event, and the associated corrective actions (LER 90-36) were adequate.

C. Unit 1 Reactor Trip on September 10, 1990

At 12:01 p.m. on September 10, 1990, an automatic reactor trip from 80% power occurred at Salem Unit 1 when the water level in the No. 13 steam generator (SG) reached the low-low level setpoint. The steam generator level shrink was a result of the unexpected closure of all four main turbine governor and stop valves. This occurred when operators closed one of the governor/stop valve pairs while preparing to isolate a high pressure turbine drain line steam leak. The licensee's post trip review determined that Operations personnel failed to initiate and implement an adequate troubleshooting plan for the steam leak. A procedural inadequacy and lack of specific training also contributed to the trip. As a result, an initial condition of greater than 85% power for the turbine valve test procedure (OP III-1.3.3) being used by the operators was not met. A resulting abnormal governor valve arrangement during the planned No. 11 governor valve closure, combined with the steam leak and an open drain valve, caused the high pressure turbine to be deflected. This caused an oscillation of the shaft and the electro-hydraulic (EH) speed pick-up sensor failed high, simulating an over-speed condition and driving all four governor valves shut. This valve closure combined with feed/steam flow mismatch, caused a shrink condition in all four SGs.

Plant response to the trip was normal. However, one intermediate range nuclear instrument (N35) appeared to be under compensated, and therefore the source range instruments had to be manually unblocked by the operators as power decreased following the trip. The licensee found a bad connection for the N35 detector in containment and made the necessary repairs. The licensee inspected the EH system and turbine in conjunction with the vendor. Repairs were made to the EH speed pick-up sensor. No additional problems were noted, the unit was restarted on September 13, 1990, and the turbine was synchronized at 6:40 a.m. on September 14, 1990. A significant event response team (SERT) was formed and independently determined the root cause.

The inspector monitored post-trip conditions including emergency operating procedure implementation, selected control room instruments and chart recorder traces, and operator performance. The inspector also reviewed the computer sequence of events log and noted that the reactor trip first-out annunciator was "13 SG level low-low".

Additional followup included discussions with the licensed operators, operations and plant management, and corporate management. A review of procedure OP III-1.3.3 confirmed that the initial condition requiring greater than 85% power was not met nor was a formal troubleshooting plan developed. This failure to follow the operating procedure is a licensee identified violation and is not being cited because the criteria specified in section V.G of the Enforcement Policy were satisfied (NON 50-272/90-22-01).

The inspector reviewed AD-16, "Post Reactor Trip Review", LER 90-30, and the SERT report. The inspector concluded that the licensee performed a thorough review for root cause and developed good corrective actions. Corrective actions included: (1) repair of the steam leak, nuclear instrument N35, and the EH system; (2) inspection of the turbine-generator; (3) performing a special monitoring program during turbine-generator startup; (4) revising the turbine-generator operating procedures OP III-1.3.1 and III-1.3.3; (5) counseling operators and operations management personnel involved in the troubleshooting activities; and (6) developing an operations troubleshooting procedure. Weaknesses associated with troubleshooting activities are discussed in section 4.3.3.A of this report.

D. Auxiliary Feedwater Storage Tank Overfill

On August 12, 1990, at 8:00 a.m., the auxiliary feedwater storage tank (AFWST) was overfilled by plant operators, spilling water and hydrazine into a storm drain. This same event had previously occurred on June 22 and July 21, 1990. Each overfill took place for a very short time (less than five minutes). In five minutes, 3000 gallons and 0.1 pounds of hydrazine can be displaced into the storm drain. The reportable quantity to the state and and the EPA is 1.0 pounds of hydrazine, therefore, in each case, no report was required.

The inspector reviewed the Incident Reports (IRs) for the June 22 and July 21, 1990, events and found that in the June 22, 1990, report an entry into the night order book was made stating that while filling the AFWST, the operator should station a nuclear equipment operator with a radio to ensure the AFWST does not overflow. After the July 21, 1990, event, the IR stated that the root cause was that the control room operator became distracted by other events and forgot to close the valve. The unit shift supervisor then held a discussion with the operator involved and other operators concerning the night order book requirements. A clear control room console cover, stating those requirements, was then placed over the pushbutton for the AFWST fill valve (DR-6).

The inspector spoke with one of the operations engineers concerning the August 12, 1990 incident. He stated the root cause to be a noncompliance with the night order entry. The operations engineer said that the personnel involved were counseled. The Operations manager also discussed this issue with all the shifts. After discussions with the reactor operators (ROs), the operations engineer retracted the previous night order entry and made another night order entry to instruct the ROs to open the DR-6 valve when filling the AFWST and to close the valve when the low level alarm cleared. Previously, DR-6 would remain open so that the AFWST could be filled beyond that point. The operations engineer then requested engineering to look into the issue to find a more permanent solution. The overfill of the AFWST has occurred three times within a two month period of time. The corrective actions, currently in place, have been found to be an effective short term solution.

E. Reduced Reactor Coolant System (RCS) Inventory Operations

On August 17, 1990, an electrical fault was discovered on the No. 14 reactor coolant pump (RCP) motor (see section 2.2.1.A). In order to replace the motor, Unit 1 was required to enter a reduced inventory/midloop condition.

The RCS was in a good configuration for the reduced inventory/midloop condition. The decay heat levels were very low (approximately 5.75 megawatts-thermal) due to 30 days of shutdown time, and the only type of RCS boundary work was for the RCP motor changeout.

Prior to entering the reduced inventory condition, operating procedures II-1.3.6, "Draining the Reactor Coolant System," and AOP-RHR-2, "Loss of Residual Heat Removal Cooling - RCS Level Below the Pressurizer," were reviewed by the Stations Operations Review Committee (SORC). A safety evaluation, Engineering Memorandum No. 90-099, that justified the RCS vent size during midloop operation for this particular outage, was approved. Training was given to the operations and maintenance staffs, including the supervisors. The inspector attended the training and concluded that it was satisfactory.

The inspector reviewed the licensee's response to Generic Letter No. 88-17, "Loss of Decay Heat Removal," along with the above mentioned operating procedures, and the safety evaluation. The inspector periodically monitored control room operations and toured containment to visually inspect the level instrumentation, the level taps, and the tygon tubing backup level indicator. The inspector concluded that the licensee adequately implemented the issues discussed in Generic Letter No. 88-17 (Expeditious Actions). NRC Inspection 50-272/89-07 and 50-311/89-06 closed this item per TI 2515/101. The inspector also concluded that the licensee effectively conducted midloop operations in a safe and proper manner.

F. Engineered Safety Feature (ESF) Actuation and Inoperable Safeguards Equipment Control Train

During a review of an ESF actuation that occurred on September 22, 1990, the inspector identified concerns relative to the review of a test anomaly and the timeliness of corrective actions for an operational event. Some intradepartmental and interdepartmental communication deficiencies were also identified.

On September 21, 1990, Maintenance personnel completed a periodic functional surveillance test for the No. 2C safeguards equipment control (SEC) train. The SEC is designed to start and load safety equipment onto the vital electrical system under accident and/or blackout conditions. A new test procedure, No. S2.MD-FT.SEC-0003(Q), "ESF Actuation Signal Instrumentation Monthly Functional Test-2C SEC Logic", was being used for the first time on installed equipment. The procedure was a recent product of the Procedure Upgrade Project. During the test, the technician and supervisor noted that an accident loading input light (No. 1) had illuminated and then extinguished for no apparent reason. This unexpected anomaly was documented in the completed procedure comments section, and the test was satisfactorily signed off.

On September 22, 1990, Operations personnel conducted a monthly surveillance test of the 2C emergency diesel generator (EDG). Upon successful completion of the test, an operator reset the 2C SEC as required. Several minutes later, the 2C SEC spuriously actuated at 2:45 a.m. The associated equipment automatically started as designed (e.g. emergency core cooling system pumps and No. 2C EDG). The 2C SEC was then reset and all components were secured. The NRC was notified of the ESF actuation via the Emergency Notification System in accordance with 10CFR50.72 reporting requirements.

On September 24, 1990, the inspector reviewed the event and found that the 2C SEC had not been declared inoperable and no troubleshooting or additional testing activities had been initiated. The licensee stated that there was no indication of an existing fault condition as the SEC self-test was not in alarm. Based on these items the SEC was not declared inoperable. However, the inspector determined that no actions were initiated following the September 22, 1990, ESF actuation due to apparent communication problems between Operations and Maintenance personnel. Also, the inspector found that the significance of receiving the input No. 1 light during conduct of the September 21, 1990 surveillance test was not properly evaluated by staff personnel nor was it communicated to the appropriate level of Maintenance supervision. It was subsequently determined that during the test on September 21, 1990, the 2C SEC output had been disconnected by procedure, and if connected, an ESF would have occurred. This was a precursor to the September 22, 1990, event which was not recognized by the licensee.

Later on September 24, 1990, the licensee decided that it would be appropriate to conduct the 2C SEC functional surveillance test in an attempt to verify operability or identify potential problems. During the test, the accident loading input No. 1 again spuriously illuminated. Since, by procedure, the SEC output was disconnected, no equipment actuations occurred. The SEC was immediately declared inoperable and a unit shutdown was initiated in accordance with Technical Specification (TS) requirements. The NRC was properly notified of the initiation of the shutdown in accordance with 10CFR50.72 reporting requirements.

Subsequent troubleshooting activities, an engineering evaluation and discussions with the vendor postulated that a faulty SEC input relay caused the accident loading signals. The relay was replaced, the SEC was satisfactorily retested, and the unit shutdown was terminated at 75% power at 12:10 a.m. on September 25, 1990. The licensee is continuing efforts to develop additional periodic checks to confirm the cause of the event and to detect relay degradation to prevent further similar actuations. The unit was then returned to full power.

The inspector concluded that, although a precursor on September 22, 1990, was not properly evaluated and corrective actions for an ESF actuation were not initiated in a timely manner, the SEC could have properly actuated and performed its intended function if needed. The failure mechanism appeared to generate unnecessary input signals, however, an actual signal to actuate the SEC would not have been inhibited. Nevertheless, several problems were noted, including poor intradepartmental and interdepartmental communication, ineffective review of a completed surveillance procedure, and untimely initiation of corrective actions for the September 22, 1990, ESF actuation. These concerns were discussed with the licensee. The inspector will closely follow licensee activities in this regard.

G. Reactor Coolant System (RCS) Spill During System Filling

On August 30, 1990, a minor reactor water spill onto the Unit 1 containment floor occurred while in Mode 5 (Cold Shutdown), during the RCS fill and vent process. The spill occurred because two reactor head vent valves (1RC38 and 1RC39) were left open during the RCS fill evolution. A roving firewatch noticed the spill and immediately notified the control room. Approximately 70 gallons of water spilled and was then drained into the containment sump. The pressurizer level at the time of the spill was approximately 90%. The licensee generated an Incident Report (IR) for this event.

The inspector reviewed Operating Department procedures II-1.3.6, "Draining the RCS" and II-1.3.4, "Filling and Venting the RCS," and the IR. Step 5.1.12 of procedure II-1.3.6 required the vent valves to be open; however, neither procedure directed closure of the valves. An initial condition of the fill and vent procedure (Step 2.1.1) states that a list should be generated of all components that are off-normal and that they should be evaluated for their effects on normal system operation. The licensee stated that these valves were on the generated list, however, they were not properly evaluated by the operator. The root cause of this spill was oversight by the control room operator who failed to thoroughly evaluate the off-normal valve report. The procedural weakness, the vent valves were not directed to be closed, was also a contributing factor. The licensee discussed this event with the operator involved, and initiated a procedure change to add a step to procedure II-1.3.4 to close the 1RC38 and 1RC39 vent valves. The revision will be completed prior to the next drain down condition. The inspector concluded that the licensee performed an adequate review of the spill, and had no further questions at this time.

H. Incident Reports

(Closed) Unresolved Item 50-272 and 311/90-81-05. Incident Reports (IRs) were not written for several events which warranted such documentation per procedure NA-AP-006, "Incident Report/Reportable Event Program and Quality/Safety Concerns Reporting System".

The inspector reviewed the criteria listed in NA-AP-006 for writing incident reports and also reviewed sample IRs 90-316 and 90-325. The procedure implies, although does not clearly specify, that IRs should be written for such events as the Boric Acid Transfer (BAT) pump surveillance test failures noted by the Integrated Performance Assessment Team (IPAT). As stated in PSE&G's response to the IPAT findings, the licensee believes that IRs should have been written for these test failures.

The IPAT stated that several instances of safety tagging errors were not documented in IRs. The source of this information was apparently a discussion with no specific examples provided. As a result, neither PSE&G nor the inspectors were able to specifically identify these safety tagging errors. Discussions with Operations personnel involved with the tagging process indicated that they were aware of the incident reporting system requirements for safety tagging errors and used the process as designed. Review of the IR logs indicated that over 600 IRs were written at Salem station in the first eight (8) months of 1990 and about 1000 in 1989. Further, these reports appeared to be properly screened for LER reportability and event evaluation and follow-up. No significant backlog existed in the program.

No violation of NRC reporting requirements resulted from the lack of IRs written on the BAT pump issues. Correction of the BAT pump Inservice Testing (IST) failures were adequately ensured by other programmatic mechanisms exclusive of the incident reporting system. Based on this review, the inspectors concluded that the criteria for writing IRs are sufficiently descriptive and encompassing to achieve the goals of the system. The system is clearly adequate as a screening tool for identifying reportable incidents. The incidents noted by the IPAT were isolated incidents of personnel misunderstanding the criteria for incident reporting or the need for filing incidents reports. The inspectors concluded that this problem will be remedied as experience is gained with using NA-AP-006 (implemented in mid 1989) and with continued management emphasis on the program. This unresolved item is considered closed.

I. Premature Tagging Release of Safety Equipment

On September 19, 1990, prior to post-maintenance testing, and while personnel were inspecting the Unit 2 No. 22 containment fan cooling unit (CFCU), tags were prematurely released, equipment was returned to service, and the No. 22 CFCU was started. Men working around the CFCU motor were unaware that the motor was going to be started. No one was injured in the incident. However, the incident could have resulted in personnel injury or equipment damage. The licensee's investigation following the event found the sequence of events to be:

-- Maintenance Supervisor requested a temporary release of paperwork to reduce technician heat stress and exposure.

-- Control Room operator called the maintenance supervisor to inform him that they were releasing the tags.

-- Maintenance Supervisor told the operator not to start the CFCU until he gave the authorization.

-- One of the test groups was setting up equipment in the switchgear room to take data during the CFCU operational test. After they were set up, this supervisor called the control room to tell them that they were ready.

-- The operator believed that the above mentioned call was the authorization to start the CFCU. The fan was started.

-- A few minutes later, the operator received a phone call from an electrician in containment informing that he was very close to the CFCU when it was started.

Poor intra and interdepartment communication contributed to the event. However, the root cause was attributed to the unauthorized release of the tags on equipment that still had personnel working on it. The release of the tags left the CFCU ready to be started automatically at any time by the associated Safeguard Equipment Control train. The inspector conducted an independent review of this event and concluded the root cause to be a failure to follow Administrative Procedure No. 15 (AP-15), "Safety Tagging Program." This was complicated by the communication problems between Operations, Maintenance and Testing personnel.

AP-15 states in section 7.3, "Temporary Tagging Release," that the Job Supervisor shall ensure all personnel are clear of the equipment and the work activity covered by the tagging has been suspended. The failure of the Job Supervisor to clear all personnel prior to requesting the temporary tagging release is a licensee identified violation of AP-15, and is not being cited because the criteria specified in Section V.G of the Enforcement Policy were satisfied (NON 50-311/90-22-01).

J. Licensed Operator Medical Records

On August 28, 1990, the inspector reviewed the medical records of four Salem licensed reactor operators. The licensee requires licensed operators to take a physical exam every year. The exams for 1989 and 1990 were reviewed and the inspector found that Form NRC-396, "Certification of Medical Examination by Facility Licensee," was filed as required with the physical exams. Part 55.21 of 10CFR states that the licensee shall have a medical examination every two years and Part 55.23 states that Form NRC-396, shall be completed and signed by an authorized representative of the facility licensee. The inspector noted that the medical records demonstrated that each operator reviewed was fit for duty. The inspector also noted the licensee to be conservative in their approach of conducting an exam every year versus the required every two years. No deficiencies were identified.

2.2.2 Hope Creek

A. High Pressure Coolant Injection System (HPCI) Inoperability Due to Moisture in Lube Oil

On September 14, 1990, the licensee reported that the HPCI system had been declared inoperable due to a high moisture content (0.04%) in the HPCI turbine lube oil. (A similar event occurred on June 7, 1990 and is discussed in Licensee Event Report 90-009-00.) The lube oil sump was drained and the lube oil cooler was pressure tested in an attempt to determine the source of the water. The test was satisfactory, and no obvious signs of leakage were detected.

There is no Technical Specification limit on HPCI lube oil moisture content. The licensee used a vendor (General Electric) recommended limit of 0.01% moisture content. The sump was filled with fresh oil, HPCI was operated and another sample drawn and analyzed with a resulting moisture content of 0.03%. General Electric was consulted and recommended a revised maximum limit of 0.2%. A significant moisture content (10-20%) could lead to swelling of the turbine oil filter and consequent flow reduction. The safety significance of this event was minimal because of both the moisture content necessary to cause filter degradation (10-20%) and the fact that both the automatic depressurization (ADS) and reactor core isolation cooling (RCIC) systems were operable while HPCI was out of service. The licensee changed their limit to 0.2% moisture and declared HPCI operable on September 16, 1990. The licensee plans to pursue identification and correction of the source of leakage during the upcoming refueling outage with technical assistance from the vendor's systems group. The inspector reviewed the licensee's actions and planned activities and found them to be satisfactory.

B. Drywell Unidentified Leak Rate

On September 4, 1990, following a power reduction during the previous weekend for turbine control valve surveillances, shift personnel reported that drywell unidentified leakage had increased from about 0.6 gallons per minute (gpm) to approximately 1.0 gpm. The leakage then decreased to a constant rate of about 0.8 gpm. The licensee's initial investigation indicated a possible leak in the area of the "C" drywell cooler, although the exact cause could not be identified. Unidentified leakage increased to 1.6 gpm over the weekend of September 22-23, 1990, following a power reduction for control rod scram timing, then gradually decreased to a constant value of 1.45 gpm. An analysis of the drywell floor drain sump water indicated that 25% of the contents was reactor coolant. Further investigation indicated that the source of leakage could be near the "B" reactor recirculation pump, but again the exact source could not be determined. At the close of this reporting period, drywell unidentified leakage remained constant at about 1.5 gpm.

The inspector reviewed the leakage monitors, discussed the occurrence with licensee personnel, and reviewed the appropriate Technical Specifications. The licensee demonstrated an appropriate safety perspective with an aggressive investigation in attempting to identify the leakage source. The Technical Specification limit on unidentified leakage is 5 gpm. The licensee imposed administrative limits of 2.5 gpm or a significant increasing trend by night order entry on September 5, 1990. Additionally, the licensee has minimized the number of power reductions as there appears to be a link between recirculation pump speed and unidentified leakage. Also, monitoring of recirculation pump seal performance has been instituted whenever pump speed is changed. The inspector had no further questions at this time.

C. Apparent Fuel Pin Leak

On September 25, 1990, at about 1:00 p.m., the Hope Creek control room received high radiation alarms on the radwaste area exhaust and the off-gas (OG) pre-treatment monitors. An OG pre-treatment sample was taken and revealed a noble gas level of about 14,000 microcuries per second. This was 4% of Technical Specification (TS) limit per TS 3.11.2.7 (330 millicuries per second). The licensee did not initially see any increase in the north or south plant vent radiation monitor. After a few days the north plant vent monitor increased from 10 to 40 microcuries per second and the south plant vent monitor increased from 140 to 180 microcuries per second. The OG stream is filtered and delayed to allow for isotope decay. The stream is then mixed with the plant vent for further dilution. General Electric and the corporate fuels group were contacted and they believe these results to be indicative of a pinhole leak in a single fuel rod. On Saturday, September 22, 1990, the unit reduced power to 80% to perform scram time testing on 10% of the control rods as required by TS. The unit then returned to full power using a new rod pattern and adhering to the power increase ramp rates. By 8:00 a.m. on September 26, 1990, the OG pre-treatment radiation monitor decreased and an OG sample pre-treatment indicated 3,000 microcuries per second. By the end of the period (October 1, 1990), the value had decreased to 1700 microcuries per second. The licensee is continuing to evaluate this situation and to take samples of reactor water and gaseous release streams.

The inspector discussed this item with licensee engineers, operators and management personnel. The inspector also monitored the radiation monitoring system (RM-11) for the affected process streams and area monitors. The inspector concluded that the licensee was aggressive in their program for monitoring this apparent fuel pin leak.

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 Inspection Findings and Review of Events

3.2.1 Salem

No noteworthy findings were identified.

3.2.2 Hope Creek

No noteworthy findings were identified.

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 1	Various	14 Reactor Coolant Pump Motor
Salem 2	Various	22 Containment Fan Coil Unit Motor
Salem 2	WO 900602016	Replace No. 23 Charging Pump Room Cooler
Salem 2	WO 900827177	Inspect/Repair Leaking Service Water Component Cooling Pump Room Cooler Valve
Salem 2	WO 900123123	Temporary Modification No. 90-057
Hope Creek	Various	"A" Safety Auxiliary Cooling System Pump Replacement

The maintenance activities inspected were effective with respect to meeting the safety objectives of the maintenance program. However, as discussed in other sections of this report, there were several examples of improper communications, both within the Salem Maintenance organization and among other Salem station groups.

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)4.0.5-P-AP(13)	Inservice Testing - Auxiliary Feed Pump Test
Salem 2	M3Q-2	Reactor Trip Breaker Semiannual Inspection, Lubrication and Testing
Hope Creek	HC.RE-ST.BF-001(Q)	Control Rod Drive Scram Time Determination
Hope Creek	HC.OP-ST.AC-001(Q)	Turbine Overspeed Protection System Operability Test (Weekly)
Hope Creek	HC.OP-ST.AC-002(Q)	Turbine Overspeed Protection and Bypass Valve Verification (Monthly)

Except as discussed below, 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. Boric Acid Transfer (BAT) Pumps

(Closed) Unresolved Item 50-272 and 311/90-81-11, Inservice testing (IST) deficiencies for the BAT pumps. The Integrated Performance Assessment Team (IPAT) team (NRC Inspection 50-272 and 311/90-81) identified an instance where the No. 22 BAT pump apparently failed an IST test and had fallen into the required action range. However, the BAT pump system engineer may have authorized acceptance of the pump test and lowered the acceptance criteria for the pump. Additionally, a concern was expressed by the IPAT that the Salem units were being operated in an unanalyzed condition because the BAT pumps were being accepted with less than the pump manufacturer's data and the FSAR stated value.

The inspector reviewed the IST records for BAT pump Nos. 11, 12, 21 and 22 as well as the baseline data used since 1988. The performance of the BAT pumps has historically degraded at such a rate that trending of pump performance was difficult. In the particular instance noted during the IPAT, the inspector found that PSE&G had rebaselined the pump performance curve to accept the BAT pump No. 22 performance test on February 8, 1990, which was now in the acceptable range (re-baselined range) and subsequently returned the pump to operable status. However, IST pump tests of January 29, and February 1, 4, 7, 1990, were rejected due to the pump failing to reach an acceptable flow rate at the required pressure. The inspector did note that the latter three of these four completed IST pump test procedures were not maintained in the IST files, but rather were located in the document control system with the maintenance work request package. This was the apparent source of a discrepancy noted between the findings of the IPAT and a subsequent review of this matter by PSE&G, as documented in their response to the IPAT findings and presented to NRC Region I on August 15, 1990.

The inspector concluded that PSE&G did not accept BAT pump 22 with performance in the alert range relative to the baseline standard (derived as delineated in ASME Section XI) in place for that pump at that time. Further, review of the design requirements for these pumps also indicates that the baselines established for all the BAT pumps, in all cases, were substantially above the minimum TS flow requirements of these pumps (10 gpm), although the inspector considered that flow rate technically unacceptable as a performance requirement for pumps designed to produce 75 gpm, per the FSAR. Thus, the plant was never operated in an unanalyzed condition nor in violation of TS requirements.

The inspector also noted that ASME Section XI, Article IWP-3111, requires that when new baseline standards for pumps are established following modification and maintenance, a documented evaluation of the recorded pump test reference values used for baselining, as compared to the pump operational requirements, must be performed. Further, 10CFR50.59 requires that changes to the plant or procedures, as described in the FSAR, be evaluated and a written safety evaluation performed. This provides the bases for the determination that the change, test or experiment does not involve an unresolved safety question. No such evaluations were documented for the change in pump performance requirements needed to return the BAT 22 pump to service on February 8, 1990. Further, no evidence was identified that such evaluations were performed on any of the other BAT pump re-baselinings made in the past. The failure to perform this 10CFR50.59 evaluation, which also serves to satisfy the requirements of ASME Section XI, is a violation (VIO 50-272 and 50-311/90-22-02).

The inspector reviewed PSE&G's response to the IPAT on this issue and noted that PSE&G acknowledged the failure to perform 10CFR50.59 and ASME Section XI evaluations of the re-baselining of the BAT pumps. As a result, 10 CFR 50.59 evaluation No. 272/311-90-81-Q060, dated May 25, 1990, was written to address this issue. The evaluation provided the basis for the 10 gpm flow requirement for the BAT pumps from TS 3/4.1.1.1, established an administrative low flow limit of 47.5 gpm at 235 ft. total dynamic head (TDH) for all BAT pump IST surveillances, and justified an FSAR minimum flow value of 45 gpm at 235 ft. TDH (versus the 75 gpm presently listed). The administrative limit of 47.5 gpm includes a 45 to 46 gpm alert range and an action range below 45 gpm. The inspector reviewed the safety evaluation and found it to be technically acceptable.

Technical Department procedure No. TI-28 was changed on June 29, 1990, which provided additional guidance to system engineers for baselining ASME Section XI pumps. The procedural changes require 10CFR50.59 evaluations for pumps if they are going to be accepted below pump operational design criteria or below the administrative limit. Operations department procedures for boration activities were also revised to incorporate the new FSAR low flow limit. Additionally, all other pumps in the IST program were reviewed to ensure that their most recent IST test results compared favorably to their design operational requirements.

The inspector considered these corrective actions to be comprehensive enough to address this matter. As a result, no response to the Notice of Violation on this issue is required. Therefore, this unresolved item and the violation are considered closed.

B. Containment Liner Corrosion

(Open) Unresolved Item 50-272 and 311/90-81-21, Corrosion visible on the liners of both containment buildings at Salem.

The inspector discussed this issue with the Manager - Civil Engineering. PSE&G believes the cause of the corrosion noted by the Integrated Performance Assessment Team (IPAT) was minor surface rusting caused by service water spillage over the years. However, in response to the IPAT finding and recent NRC information regarding corrosion of steel containment vessels (i.e. Information Notice 89-79 and Supplement 1 to the Notice), PSE&G contracted Stone and Webster Engineering Corporation (SWEC) to perform a study of the containment liner corrosion. The inspector reviewed SWEC's draft report and found it technically adequate, although the recommendations provided were non-specific with regard to key elements of any inspection program (i.e. statistically representative sampling sizes for liner thickness measurements). The inspector did note that the report stated that the containment liner was designed to be protected by an installed cathodic protection system. However, the SWEC report did not recommend confirming the installation or operability of this system. Later discussions between the inspector and the system engineer for the cathodic protection system determined that no such system existed at either of the Salem units. PSE&G immediately initiated actions to follow-up on this finding at the conclusion of this inspection.

PSE&G has not yet developed a containment liner inspection program from the draft SWEC report. However, PSE&G tentatively intends to develop and implement an inspection program by the next refueling outage at either Salem unit, currently scheduled for Unit 1 in February 1991. This time schedule is considered satisfactory in that indirect long-term confirmation of containment liner adequacy via containment integrated leak rate testing and visual inspection has never identified any corrosion induced failure of the containment liner at either Salem unit.

The inspector considered PSE&G's actions to date in this matter responsive to the NRC's safety concerns. This unresolved item will remain open to allow for tracking the issue for NRC review of PSE&G's inspection findings for generic industry implication and to evaluate the need for future regulatory action.

C. Unit Shutdown During Surveillance Test Due to Inoperable Computer

On September 21, 1990, Unit 2 commenced a Technical Specification (TS) required shutdown due to the inability to complete time response testing of the "B" reactor trip breaker (RTB). During performance of the RTB surveillance, the process computer (P-250) power supply failed, making the P-250 inoperative. The P-250 is used for RTB time response measurement, and its unavailability delayed completion of the surveillance test. The test began at 2:50 p.m. The Action for the applicable TS (No. 3.3.1 - Action 20) allows the "B" breaker to be in the bypass position for up to two hours. After the two hours expires, Mode 3 (Hot Standby) must be reached in the next six hours.

The licensee was in the process of pursuing the use of an alternative device to measure the RTB time response when the two hour time limitation expired. Then, at 5:51 p.m., a unit shutdown was initiated in accordance with TS requirements. This was reported to the NRC via the Emergency Notification System in accordance with 10CFR50.72 reporting requirements. A procedure change was subsequently processed, and the RTB time response measurements were taken using a calibrated chart recorder. The unit shutdown was terminated at 58% power and the TS Action Statement was exited at 8:11 p.m.

A licensee Quality Assurance (QA) inspector was present during conduct of the September 21, 1990, test. On September 24, 1990, the QA inspector identified and pursued several concerns related to the conduct of the surveillance test. There were two TS Action Statements applicable during the surveillance test. The procedure appropriately directed entry and exit of those requirements. However, the QA inspector identified that due to apparent communication problems between operations and maintenance personnel, TS Action Statements were inappropriately exited. Specifically, TS Action Statement 3.3.2.1 was prematurely exited by several minutes, and TS Action Statement 3.3.1 was exited and subsequently re-entered (and restarted the time limit) when TSs should not have been exited.

The resident inspector reviewed the QA findings and found them to be valid, although no TS violations resulted. That is, if the TS Action Statement were properly exited, no required actions would have been necessary. The inspector verified that these deficiencies are being properly evaluated by the responsible station personnel.

The inspector concluded that the QA inspector properly identified, evaluated and reported a potential safety concern that resulted from interdepartmental communication deficiencies during surveillance testing. The inspector will monitor the licensee's resolution of this issue during a subsequent inspection.

D. Inoperable Auxiliary Feedwater Pump

On September 24, 1990, the licensee conducted a monthly operability surveillance test for the Unit 1 No. 13 turbine-driven auxiliary feedwater (AFW) pump using surveillance test procedure No. SP(O)4.0.5-AF(13), "Inservice Testing - AFW Pumps". After the pump was started at 3:14 a.m. the terry turbine automatically tripped unexpectedly at 3:18 a.m. Prior to the trip, the turbine was experiencing speed oscillations. The pump was restarted at 3:35 a.m. and was tested successfully until it was manually shutdown at 5:03 a.m. The surveillance was documented as being satisfactorily completed.

The trip of the No. 13 AFW pump was discussed during the September 24, 1990 daily morning meeting. The licensee suspected that the turbine may have tripped because of excessive condensation accumulation in the steam supply line, possibly due to a clogged orifice in the associated drain line. The inspector subsequently expressed concern that the AFW pump was not declared inoperable following the turbine trip. The licensee then implemented actions to monitor temperatures in the turbine steam supply line at selected locations to ascertain whether condensation was accumulating and planned to conduct another surveillance test.

On September 25, 1990, the AFW surveillance test was started at 4:28 a.m., however, the turbine tripped at 4:32 a.m. The pump was immediately declared inoperable and the appropriate Technical Specification Action Statement (TSAS) was entered. Subsequent maintenance activities identified that the orifice in the steam supply drain line was clogged, in that deposits had accumulated on the orifice opening and debris (rust) was found at the orifice flange. The system engineer was also present, and identified that the installed orifice assembly did not have the required strainer (screen) on the upstream side.

On September 26, 1990, the inspector observed the installation of the required orifice assembly, including the strainer. Further inspector review identified that a previous trip of No. 13 AFW pump during surveillance testing occurred on February 11, 1990, as documented in Incident Report (IR) No. 90-115. Corrective actions included cleaning the orifice and replacing the orifice gaskets. No additional formal followup to IR 90-115 was performed.

The system engineer also identified that the Unit 2 AFW turbine-driven pump (No. 23) uses a 1/8 inch orifice. Unit 1 has a 0.03 inch orifice (about 1/4 the size of the Unit 2 orifice). The system engineer formally requested that an engineering evaluation be performed to verify proper orifice size. AFW system differences were not identified when the Unit 1 strainer, installed initially via a 1981 modification, was removed.

The repairs to No. 13 AFW pump were completed and the pump was satisfactorily retested on September 27, 1990, including pump response time testing. Slight adjustments were also made to the turbine governor. The TSAS was properly exited on September 27, 1990, at 12:57 p.m. Licensee corrective actions included implementing continued monitoring of the steam supply line temperatures to ensure proper condensate drainage.

The inspector concluded that there was a similar previous event which may not have been properly evaluated and investigated to the extent that proper disposition may have precluded subsequent events from occurring. The inspector also concluded that the failure to declare the No. 13 AFW pump inoperable on September 24, 1990, was an error in licensed operator judgement. Specifically, although the surveillance procedure was satisfactorily completed, additional information was available which showed that pump performance and reliability were in question. The licensee agreed with this assessment and stated that Operations shift supervisors will be briefed on management's expectations relative to operability determinations. The inspector had no further questions at this time.

E. Inadvertent Main Steam Isolation Valve Closure During Surveillance Test

On August 19, 1990, during solid state protection system (SSPS) testing, one of four main steam isolation valves (MSIVs) closed unexpectedly. The unit was critical at about 2% power. The test is intended to close the associated MSIV bypass valve and main steam drain line valve for that loop, but should bypass the closure signal to the individual MSIVs. Followup licensee review determined that due to a procedure deficiency and inadequate communication the test equipment (voltage meter) was not disconnected by the technician when the test switch was placed to the "operate" position. With the voltage meter still connected to the test contacts, a low resistance path was provided, resulting in energization of the relay that actuates the associated MSIV. Inadequate communications contributed to this event in that the operator did not inform the technician prior to operating the test switch. Normally, the operator informs the technician prior to operating the test switch, and the technician disconnects the voltage meter before the operator proceeds with the test. The licensee made the necessary procedure enhancements to ensure that the meter is disconnected prior to actuating the test circuit. All remaining SSPS and MSIV isolation testing was subsequently performed satisfactorily. This ESF actuation was reported to the NRC in accordance with 10CFR50.72 reporting requirements. The inspector had no further questions.

F. Surveillance Frequency Noncompliance Due to Personnel Error

On September 24, 1990, the licensee identified that they did not comply with Technical Specification (TS) surveillance requirement 4.3.1.1. Specifically, TS Table 4.3-1 requires that a channel functional test be performed monthly for the safety injection input from the solid state protection system (SSPS), however, the licensee found that they have historically performed that test once every 62 days on a staggered test basis. This discrepancy was identified during a TS verification audit, being performed to ensure all TS surveillance requirements are met.

The licensee determined that the root cause of this event was personnel error. The licensee also determined that the staggered test basis frequency for the above surveillance requirement is consistent with the current Westinghouse Standard TSs. Therefore, a TS change request has been initiated.

Upon discovery of this event, the appropriate Unit 1 and 2 SSPS channels were tested satisfactorily. Therefore, the affected channels would have properly performed their intended functions. The surveillance procedure frequency requirements were corrected to comply with the current 31 day specification. The inspector concluded that the appropriate corrective action was completed by the licensee. The licensee identified violation of Technical Specifications is not being cited because the criteria of Section V.G of the Enforcement Policy were satisfied (NON 50-272/90-22-03).

G. Reactor Trip Breaker Test Failures

On September 24, 1990, and October 1, 1990, the licensee informed the NRC that the Unit 2 undervoltage trip attachment (UVTA) for reactor trip breakers (RTBs) "B" and "A", respectively, failed the trip bar lift force measurement test. The failures were identified during the performance of the semiannual RTB maintenance activity, which includes response time testing, trip bar lift force measurements, and UVTA output force measurements.

The trip bar lift force measurement test determines the excess margin that the RTB overcomes to trip the breaker by adding weight to the trip bar. Following the failure of the "B" RTB on September 24, 1990, as found conditions were determined. The breaker tripped with 240 grams added. The acceptance criterion is greater than or equal to 460 grams. Preventive maintenance activities were then completed in accordance with procedure M3Q-2, however, post-maintenance testing also failed to meet the 460 gram requirement. The UVTA was subsequently replaced, and was satisfactorily retested (700 grams).

When the "A" RTB failed its 460 gram UVTA trip bar lift force measurement test on October 1, 1990, the licensee decided to replace the UVTA. No additional as-found testing was performed, and the post-repair testing was successfully completed (640 grams). The licensee attributed the failure to obtain as-found data to be the result of ineffective communication between Technical Department and Maintenance Department personnel.

As documented in previous NRC inspection reports, the licensee had identified an apparent marginal lot of UVTAs received at Salem. Both of the above mentioned installed UVTAs were from that lot. The previous NRC inspections had concluded that considerable margin remained to trip the breakers based upon as-found testing results of at least 380 grams. However, the as-found margin for the "B" RTB was only 240 grams and that for the "A" RTB was not determined.

The existing Unit 1 and 2 Technical Specifications (Table 3.3-1) require that the licensee immediately report to the NRC and prior to any repair or maintenance any failure to meet the RTB or bypass RTB trip force requirement. The licensee recently received a Technical Specification amendment (not yet implemented), which relaxed the Salem specific conservative reporting requirement to a 300 gram threshold for the trip bar lift force measurement. The licensee stated that procedures will be changed to require as-found testing following initial test failure.

The inspector will continue to monitor licensee efforts in this area with regard to potential UVTA problems.

H. Inservice Testing (IST) Program

(Open) Unresolved Item 50-272/89-11-06, failure to properly mark the auxiliary feedwater (AFW) pumps for inservice testing (IST) vibration probe placement. The scope of this unresolved item will be expanded to include all pumps in the IST Program.

In response to previous NRC findings (Inspection Report No. 50-272/90-03), the licensee stated that by March 31, 1990, one-inch paint marks would be provided to identify specific pump and motor vibration measurement points. In a memorandum dated May 8, 1990, Engineering stated that they completed the program to mark the pumps for vibration readings. During this inspection period, the inspector visually checked several of the pumps and found specific vibration markings missing. The inspector brought this to the attention of the responsible IST program engineer who stated that he had recently completed a check of the pumps and was aware of the problem. He also stated that the pumps had all been marked, however since that time, maintenance work on charging and safety injection pumps had removed selected markings. The inspector concluded that the initial actions taken were satisfactory. However, administrative controls to maintain the markings have been ineffective. As a corrective action, procedure No. SP(O) 4.0.5-P-GEN, "Inservice

Testing Guidelines," will be changed to instruct the operator performing the test to notify the appropriate personnel if any of the vibration measurement markings are missing. The operator is not to continue the test until the markings have been reapplied.

As a future action for the vibration readings, the licensee plans to permanently attach bayonet mounts to the pumps for the vibration probes, however, they are currently investigating whether these mounts will constitute a design/configuration change to the components. This item will remain open pending completion of the program to mark the IST pumps for the vibration probe readings.

4.3.2 Hope Creek

A. Technical Specification (TS) 4.0.5

On August 13, 1990, the licensee identified that the "B" service water system spray wash pump had not been tested for a re-baseline after maintenance was performed in July 1990. This condition constituted a violation of Technical Specification (TS) 4.0.5 and ASME Section XI criteria. The licensee identified violation is not being cited because the criteria specified in Section V.G. of the Enforcement Policy were satisfied (NON 50-354/90-16-02).

The root cause of the violation was identified as inadequate review of a completed work order on July 6, 1990, by a nuclear shift supervisor (NSS). The work order included maintenance activities for an oil flinger ring adjustment and replacement of a new mechanical seal. The NSS thought that only the flinger ring was worked, and he deleted the retest requirements as the ASME Code requires retesting if pump disassembly was required, and the flinger ring adjustment could be made without disassembly of the pump. A retest performed on August 13, 1990, was satisfactory as there were no significant deviations from the previous baseline data.

The inspector reviewed the licensee event report (LER 90-13), the incident report and the work order. The inspector concluded that the LER was factual, and that licensee corrective actions were adequate. The inspector had no further questions at this time.

B. Reactor Core Isolation Cooling (RCIC) System Isolation During Testing

On August 21, 1990, the licensee reported than an emergency safety feature (ESF) actuation signal had been received which shut the RCIC system inboard steam isolation valve. After determining the cause of the isolation, the isolation logic was reset and the valve was reopened, returning RCIC to its normal standby lineup. The isolation was caused by personnel error by Maintenance technicians performing a surveillance test on the steam leak detection system circuitry associated with the RCIC isolation valve. The technicians failed to place a keylocked switch in "bypass" as required by the test procedure (IC-FT.SK-001, step 5.1.2). Failure to follow the surveillance procedure is a licensee identified violation and is not being cited because the criteria specified in Section V.G of the Enforcement Policy were satisfied (NON 50-354/90-16-01).

The licensee's investigation determined this was an isolated event, and the technicians involved were counseled with regard to job performance expectations and the use of helpers during surveillance testing. This event was documented in Licensee Event Report (LER) 90-015. The inspector reviewed the event, the LER, and discussed the event with licensee personnel. The licensee's corrective actions appear to adequately address the root cause of this event. The inspector had no further questions at this time.

4.3.3 Common Troubleshooting Activities

A. The inspector reviewed administrative guidance and procedural controls for troubleshooting activities at Salem and Hope Creek including:

Common

-- NA.AP.ZZ-13, "Control of Temporary Modifications"
-- NA.AP.ZZ-9, "Work Control Program"

Salem

-- OD-15, "Use of Operations Department Procedures"
-- M11E, "Mechanical Equipment Troubleshooting and Repair"
-- IC-GP.ZZ-006, "Controls Equipment - Troubleshooting"

Hope Creek

-- MD-GP.ZZ-008, "Equipment Troubleshooting"
-- IC-GP.ZZ-008, "Maintenance Troubleshooting"

Based on this review, the recent Salem Unit 1 reactor trip on September 10, 1990, as discussed in section 2.2.1.C, and the findings from the Salem and Hope Creek Maintenance Team Inspections (Report Nos. 50-272 and 311/90-200 and 50-354/90-80), the inspector concluded that there was adequate programmatic guidance for troubleshooting and adequate implementing procedures for maintenance personnel. However, there were no implementing procedures for Operations Department troubleshooting activities. The inspector discussed this item with licensee management personnel and they concurred that this is a potential programmatic weakness. The inspector will review licensee efforts in this area during future inspections.

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 10CFR50.73 were reviewed.

5.2 Inspection Findings

No noteworthy findings were identified.

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

No noteworthy findings were identified.

7. ENGINEERING/TECHNICAL SUPPORT

7.1 TMI Action Plan (TAP) Item Review

A. Salem Reactor Vessel Head Vents (TAP Item II.B.1.2 and 3)

The licensee completed modifications on both Salem units to add reactor vessel head vents. The design was approved in 1983. The NRC inspected the installation in NRC Inspections 50-272/84-08, 85-15, 86-01 and 311/84-08, 85-17, 85-20, 86-01. The item remained open pending inspector walkdown of the system, review of operating and emergency procedures, and verification of Technical Specifications (TSs).

The inspector performed a walkdown of accessible portions of the system, including control room switches and indicators. The inspector interviewed selected licensed operators to verify their knowledge, and reviewed system operating and emergency operating procedures to verify that the head vent valves were included. The inspector also verified that TS 3/4.4.12 addresses head vent valve operability, action statements and surveillance requirements. No unacceptable conditions were noted and TAP Item II.B.1.2 and 3 are closed for Salem Units 1 and 2.

B. Hope Creek Control Room Habitability (TAP Item III.D.3.4.2)

Hope Creek Control Room Habitability (TAP Item III.D.3.4) Section II.D.3.4 of NUREG-0737, "Clarification of TMI Action Plan Requirements," required the licensee to assure that control room operators would be adequately protected against the effects of accidental release of toxic and radioactive gases. The item also required that the plant could be safely operated and shutdown under design basis accident conditions. The licensee's submittals to the NRC in support of an application for an operating license detailed the means by which the licensee proposed to meet these requirements. The NRC staff determined that the licensee had demonstrated that the control room habitability systems would adequately protect the operators and found the licensee in compliance with NUREG-0737, TAP Item III.D.3.4 (see NUREG-1048, "Safety Evaluation Report (SER) related to the operating of Hope Creek Generating Station", October 1984, Attachment 6.4).

A number of issues were not explicitly discussed in the SER. However, data was required by NUREG-0737 and the licensee included discussion of and actions taken to address these in section 6.4 of the Updated Final Safety Analysis Report (UFSAR). These issues were reviewed by the inspector as follows:

- The licensee committed to having a minimum of a five day supply of food and water for five persons available within the control room envelope (as defined in Figure 6.4-1 of the UFSAR). A locked freezer is located in a dedicated storage area. The freezer's contents were noted to be in excess of the 75 meals (three meals/day per person) required. Additionally, a supply of fresh water is provided (located in the same space as the freezer) from tank 00-T-411 which contains greater than 1000 gallons. A check valve is installed in the tank fill line to prevent draining the tank should normal system pressure be lost. The tank can be isolated from exterior water sources and be pressurized by a small air compressor. The freezer is completely restocked annually. The inspector noted, however, there was no formal program to assure an annual replacement or to periodically verify the edibility of the frozen food. Operations management immediately issued an order to obtain replacement food annually.

- A first aid kit for minor injuries is located in a second cabinet across from the operator's ready room. An additional first aid kit and assorted bandages is located in the senior nuclear shift supervisor's (SNSS) office. The site also has a full-time emergency medical team (EMT) for more significant injuries. Potassium iodide (KI) tablets are contained in the same cabinet as the first aid kit. The cabinet's contents are inventoried quarterly and the KI tablets are replaced if found to be within three months of their shelf life expiration date. The SNSS is authorized to obtain and issue the KI tablets as provided in the Artificial Island Emergency Plan. KI tablets are also available at a variety of locations, including the main radiological control point located just across the corridor from the control room envelope.

- At least eight sets of emergency breathing equipment are located in the hallway next to the instructional viewing area (based on a minimum of one extra set for every three sets needed to meet the minimum capacity). The equipment is inspected monthly for material condition and functionality.

- Because there are no toxic chemicals either stored on site or located within five miles of the site, the licensee determined that the requirements of Regulatory Guides 1.78 and 1.95 were not applicable to Hope Creek. While the control room outside air intakes were located to minimize the possibility of various gases entering the control room, exhaust gases from the emergency diesel generators (EDG) could enter the control room via the air intakes under certain circumstances. The licensee's analysis of this issue indicated a calculated maximum concentration of 1.6 ppm, well below the limiting threshold value of 3.0 ppm (UFSAR Sections 6.4.4.2 and 6.4.7.1). Consequently, operation of the EDGs would not compromise control room habitability. The inspector discussed with a number of operations personnel whether they noted diesel fumes when the EDGs were running. Several indicated that they had on occasion, but also indicated the fumes had created no problems. The fumes were far more noticeable in the corridor outside the control room envelope.

- Because no chlorine is stored onsite or within five miles of the site boundary, the requirement to have a chlorine detection system is not applicable to Hope Creek. The analysis also included a review of Delaware River traffic.

- Hope Creek's Technical Specifications (TSs) included the requirement that the control room emergency filtration system (CREF) be able to pressurize the control room envelope to at least 1/8 inch water gauge, and would isolate by test signals with damper closure within five seconds (TS 3/4.7.2). Surveillance tests are in place to verify system operability.

Based on this review, TAP Item III.D.3.4.2 is closed for Hope Creek.

7.2 Salem

A. System Engineer Qualification and Performance

The Integrated Performance Assessment Team (IPAT) noted weaknesses in the performance of Salem system engineers, specifically in the areas of: (1) system knowledge, (2) lack of field presence, (3) lack of a questioning attitude, and (4) lack of attention to detail. These weaknesses were categorized based on several examples of system engineer performance noted by the IPAT.

To assess the apparent weaknesses in system engineer knowledge and performance, the inspector reviewed the formal training and qualification process for the engineers and interviewed and observed system engineers. Specifically, the inspector reviewed training department procedure TQ-TP.ZZ-909(Z), "System Engineer Training," which outlines the formal classroom training and the qualification process for system engineers. The program is designed to train degreed engineers to near the level of senior reactor operators through a six month classroom and simulator training effort. The inspector reviewed the content of the training program and found it to be comprehensive and reasonably challenging. Frequent testing of the students in the program was required and remediation of individuals who failed portions of the program was provided. The process includes formal classroom and on-the-job training, demonstrated working skills, and an oral board.

Discussions between the inspector and several of the system engineers found the individuals to be knowledgeable of system/equipment design and of system status. No noteworthy performance-related issues were identified with the engineers, although only a limited number of activities were observed.

The inspector concluded that the system engineers received adequate formal training to carry out their job responsibilities. However, performance problems may exist which the IPAT identified, but were not evident to the inspector. No examples of such problems were noted during this inspection. Evidence of management commitment to improved performance was apparent.

The resident inspectors will continue to assess personnel performance in the future as part of the normal inspection program and licensee event reporting process, and will evaluate recurrent examples of poor performance which affect plant safety. No further review of this issue is warranted at the present time. Based upon the review conducted by the inspectors, no significant deficiencies were identified in the training program or qualification process for system engineers.

B. Salem Safety Equipment Room Coolers

At 2:00 p.m. on September 6, 1990, the licensee discovered a through-wall leak in the service water system piping to the No. 12 charging pump room cooler. The piping failure consisted of an approximately 2 inch long split in the pipe. The unit entered a 72 hour Technical Specification Action Statement (TSAS). The licensee stated that the charging pump operability could be restored prior to replacement of the failed piping because the room cooler is not considered to be required for charging pump operability. The licensee isolated the leak and declared the No. 12 charging pump operable before the 72 hour TSAS expired.

The inspector questioned the basis for the licensee's conclusion that the room cooler was not needed for pump operability. The licensee uses a TS interpretation per Operations Procedure No. OD-12. This procedure states that the room coolers may be out of service for seven or 31 days (depending on service water availability) without declaring the respective pump(s) inoperable. The OD-12 interpretation was based on an engineering evaluation (SGS/M-FD-29) dated October 9, 1979.

The inspector reviewed FSAR Section 9.4.2 which states that these room coolers, in conjunction with the auxiliary building air flows, limit equipment area temperatures below the environmental qualification requirements. The referenced engineering evaluation was also reviewed by the inspector, however, a sufficient basis for the interpretation was not identified.

The inspector concluded that the basis for the OD-12 interpretation was lacking sufficient detail. The licensee concurred and stated that their long term program to upgrade, revise and formally approve these interpretations (Unresolved Item 50-272/89-27-03) is currently in progress with all but four items completed. The room cooler TS interpretation is currently under final engineering review and is scheduled for completion by early November 1990.

Until this room cooler evaluation is complete, the licensee stated that they would not take room coolers out of service for scheduled maintenance. The inspector will continue to follow this area and this item remains unresolved.

C. Open Item Followup

1. (Closed) Violation 50-272/89-11-03: Failure to complete an adequate 10CFR50.59 safety evaluation to address the seismic impact of a portable reactivity computer on adjacent safety related equipment. The inspector reviewed the licensee's response and discussed the concern with the reactor engineer.

   The reactivity computer racks have been removed from the Salem Unit 1 and 2 control rooms and will only be temporarily reinstalled for short time durations (four days on the average) and controlled by procedures. As part of the control room redesign modification, the Unit 1 reactivity computer will be permanently installed, wired and operable, prior to the end of the next unit refueling outage. The Unit 2 reactivity computer is currently installed permanently in the control room, however, it is not wired and operable. This work will be completed prior to the end of the next unit refueling outage. This item is closed.

2. (Closed) Unresolved Item 50-272/89-11-10: Orifices installed backwards in the centrifugal charging pump injection lines. Licensee investigation of the event determined that the orifice configuration resulted in lower indicated flow rates in the control room. The root cause was determined to be personnel error. Through engineering calculations and discussions with the pump manufacturer, the licensee determined the following:

-- The short period of operation during the test did not cause pump damage, as verified by the pump manufacturer;

-- There was sufficient suction pressure available for all modes of pump operation;

-- The pump motors were sized to accommodate the increased flow rate; and,

-- The increased load would not exceed the allowable 2000 hour continuous load rating of the emergency diesel generators.

The licensee concluded that the systems and components affected by the reversed orifice plates would have performed their safety function if required. This event was detailed in Licensee Event Report No. 89-020. Corrective actions to prevent recurrence included the development of Procedure No. M11Y, "Flow Orifice Plate Removal and Installation," which includes areas for clear documentation of the maintenance work. Also, specific orifice installation/removal training for maintenance personnel was conducted. The inspector reviewed the licensee's event investigation findings and the subsequent corrective actions and found them to adequately address the concerns of this issue. This item is closed.

7.3 Hope Creek

A. Ultimate Heat Sink Design Deficiency

During an engineering evaluation of minimum station service water pump performance, the licensee determined that the Technical Specification (TS) limit of 90.5 degrees F was non-conservative. This 90.5 degrees F limit was established taking credit for station design margins in service water pump flow rates and heat exchanger heat removal capability. Normal expected degradation of station service water pump performance would result in potentially inadequate heat removal capabilities with river temperatures greater than 85 degrees F. Administrative limits and a TS interpretation were established to define a maximum allowable service water temperature of 85 degrees F. The licensee made an ENS call to report this to the NRC on August 17, 1990 at 8:45 a.m.

The inspector was also briefed by the licensee regarding this finding. The inspector monitored the ENS call and verified licensee corrective actions. At the time of the report, river temperature was 79 degrees F. The inspector also discussed this item with licensee engineering, operations and management personnel. The inspector reviewed LER 90-14, dated September 14, 1990, regarding this event. The licensee concluded that river temperature was greater than 85 degrees F for a six hour period on August 5, 1988, when it reached 86.8 degrees F.

A failure of one of the redundant loops of service water and safety auxiliaries cooling systems combined with river temperature greater than

85 degrees F would result in being outside the design basis for a loss of offsite power and LOCA. The licensee further concluded that this condition would have been minimized because the plant would be in a 12 hour TS Action Statement with these water systems out of service. The inspector had no further questions at this time.

8. SAFETY ASSESSMENT/QUALITY VERIFICATION

8.1 Waivers of Compliance

A. Hope Creek Emergency Diesel Generators (EDGs) Fuel Oil

On August 22, 1990, the Hope Creek chemistry department received test results from a vendor indicating that a diesel fuel oil shipment delivered on August 15, 1990, did not meet Technical Specification (TS) test criteria. PSE&G immediately sampled the fuel oil storage tank to which the oil had been delivered and shipped the sample to the vendor for testing to ensure that the tank's entire contents still met the required criteria. These test results were received on August 23, 1990, and the results indicated that the fuel oil impurity level, as measured by ASTM-D2274-70, were within TS limits. In discussing the test results with the vendor, however, PSE&G learned that the vendor was, in fact, not testing the fuel oil impurity level in accordance with ASTM-D2274-70, as required by the Hope Creek TSs. PSE&G subsequently discovered that the vendor had never performed the test per the specified standard and did not possess the equipment to do so. The licensee concluded that TS 4.8.1.1.2.f.2 had not been performed for any of the fuel oil that was in storage and that the operability of all four EDGs was in question. Consequently, the 24 hour provision of TS 4.0.3 was placed into effect at 2:40 p.m. on August 23, 1990, when the missed surveillances were discovered. This action was subsequently reported in LER 90-16.

In order to maintain the EDGs in an operable status, TS 4.8.1.1.2.f.2 had to be performed for all diesel fuel oil in storage. The time required for PSE&G to find new vendors capable of performing the required test and for the test to be carried out was going to exceed the 24 hours allowed by TS 4.0.3, so on August 24, 1990, PSE&G requested a NRC Regional Waiver of Compliance allowing a 48 hour extension of the TS. Based on other valid, satisfactory tests of the fuel oil, the NRC granted the 48 hour extension to allow for completion of the diesel fuel oil testing. All diesel fuel oil was tested and found to be within TS limits on or by August 25, 1990, with all EDGs subsequently deemed operable, and the TS Action Statement was exited on the same day.

In response to the fuel oil incident, Hope Creek Station Quality Assurance (QA) conducted a special investigation to determine the cause of the fuel oil surveillance deficiencies and to review the qualifications of the vendor who had been performing the fuel oil analyses. The investigation was concluded by the end of the inspection period, and the inspector reviewed the report the investigation team had submitted to the Hope Creek General Manager. The inspector found the report to be open and complete. The report thoroughly assessed the performance of the vendor, Hope Creek Chemistry Department, PSE&G Procurement QA, the PSE&G Research Lab, PSE&G Purchasing Department and the Hope Creek Station QA organization. The investigation team concluded that the responsibility to ensure compliance with the necessary Technical Specification was not properly understood and that there was an apparent lack of ownership on both PSE&G's and the vendor's part to ensure that the contract requirements were adhered to. Immediate corrective actions taken by PSE&G included the suspension of the use of the original vendor and the qualification of two new vendors to perform the diesel fuel oil surveillances. Longer term recommendations included the development of a formal Nuclear Department diesel fuel oil program and a review of the adequacy and currency of the TS 4.8.1.1.2.f.2 requirements. The inspector determined the corrective actions taken to be adequate and will follow up on the recommendations in a future inspection report.

B. Hope Creek Safety Auxiliary Cooling System (SACS)

On September 26, 1990, condensation was observed on the surface of the "A" SACS pump casing. A one inch linear indication was found on the pump's lower casing. The pump, an ASME Class 3 component, was isolated and tagged out of service for repairs. The NRC was informed at 10:25 a.m. The unit was placed in a 72 hour Technical Specification Action Statement (TSAS 3.7.1.1), which would expire at 9:11 a.m. on September 29, 1990. On September 27, 1990, after the "A" SACS pump had been disassembled and the inside of the pump casing examined, the licensee determined that replacing the pump casing would be more prudent than attempting a weld repair. A spare casing had already been staged in close proximity to the "A" SACS pump. By September 28, 1990, the pump casing had been replaced and pump reassembly nearly completed, leaving the final pump/motor alignment and baseline pump performance testing to be accomplished.

Any delay encountered could have extended beyond the allowed 72 hour TSAS time period. The licensee, therefore, requested from the NRC a Waiver of Compliance from TS 3.7.1.1 for a 24 hour period to provide sufficient time margin for the alignment uncertainties. The licensee submitted the request on September 28, 1990, and telephone discussion was held among licensee, NRC Region I and NRC NRR personnel. The justification for the Waiver was not thoroughly documented and the licensee submitted a followup letter on September 29, 1990. This second submittal addressed these NRC concerns. The NRC granted a Waiver of Compliance to expire at 9:11 a.m. September 30, 1990, subject to a number of conditions, including establishing roving firewatches in areas containing "B" SACS loop equipment, and conducting extensive shift turnover briefings covering the realignment of emergency diesel generator and filtration/ventilation cooling water in case of a loss of SACS. Additionally, the Waiver would terminate immediately upon it being determined that any redundant emergency core cooling equipment was inoperable.

The unit exited the TSAS and associated Waiver at 3:55 p.m. on September 29, 1990, when the "A" SACS pump was restored to an operable status. The inspector reviewed the licensee's actions relative to the conditions of the Waiver and found them to be adequate. Shift personnel were cognizant of the additional actions imposed by the Waiver and they exhibited a good safety perspective.

C. Salem Number 22 Containment Fan Coil Unit (CFCU)

The licensee requested an NRC Regional Waiver of Compliance in a letter dated September 17, 1990. The No. 22 CFCU motor had failed on low speed at 1:40 p.m. on September 11, 1990. This placed Unit 2 in a seven day Technical Specification Action Statement (TSAS) because the low speed function mitigates the post-accident containment pressure rise. The licensee requested a waiver. The failure mechanism had been well understood by the licensee and corrective actions to replace all of these motors were underway. The waiver was requested to prevent a shutdown of the unit because replacement of the motor inside containment would exceed the 7-day TSAS. NRC Region I granted a waiver to extend the TSAS for an additional six days until September 24, 1990. This was justified because redundant equipment was available to mitigate an accident during this period.

The inspector reviewed the submittal, the work in progress, and the TSAS, and discussed this item with licensee maintenance and management personnel. The inspector verified that the specific provisions of the Waiver of Compliance were adequately followed. The 22 CFCU motor was replaced, repaired, tested and declared operable. The TSAS was exited on September 20, 1990.

8.2 Salem

A. Reactor Protection System (RPS) Setpoint Changes and License Change Request

On September 4, 1990, PSE&G submitted a request, License Change Request (LCR) 89-05, for an amendment of Facility Operating Licenses DPR-70 and DPR-75 for Salem Unit 1 and Unit 2, respectively. The proposed amendment would modify Technical Specification Section 2.2, Table 2-2.1 and Section 3/4.3.2, Table 3.3-4, and incorporate new trip setpoints for steam generator water level low-low and steam line pressure low. The steam generator water level low-low setpoint would be raised from 8.5% to 16%, and the steam line pressure low setpoint would be raised from 500 psig to 600 psig.

The new, more conservative setpoints were derived as a result of a review of all RPS instrument loops by Westinghouse. This review was initiated by PSE&G to ensure existing setpoints were conservative in order to satisfy an NRC concern stemming from PSE&G's 1986 request to allow the removal of the Salem reactor coolant system resistance temperature detector bypass manifolds. When the setpoints were reviewed with the latest Westinghouse setpoint methodology, the only two setpoints shown to be non-conservative were the steam generator water level low-low and steam line pressure low setpoints. The results from Westinghouse were received by PSE&G in May 1989, and the setpoint changes were necessitated by uncertainties that had been added by replacement transmitters and the one hour harsh environment criteria which had been imposed by NUREG 0588.

While plans were being developed to implement the new setpoints, PSE&G completed an engineering evaluation in May 1989, to justify operation with the old setpoints. The inspector reviewed the evaluation for both setpoints and determined both were adequate and complete in their analysis and justification of the existing values. The licensee subsequently prepared Design Change Packages (DCP 1SC-2241 and 2SC-2241) for implementing the new setpoints, which was accomplished in November 1989. The inspector also reviewed the DCPs, found them satisfactory, and determined that a license change was not required to change the setpoints to the higher, more conservative valves since the Salem Technical Specifications only required that the setpoints be "greater than or equal to" 8.5% and 500 psig, respectively. Licensee management explained to the inspector that the LCR was not submitted until this past September due to the LCR essentially being an administrative task and other Salem projects having a higher safety significant priority. The inspector noted that LCR 89-05 was complete and accurate, and had no further questions concerning the RPS setpoint changes.

B. Station Qualified Reviewer

(Closed) Unresolved Item (50-272 and 311/90-81-16), Station Qualified Reviewer (SQR) independence for procedure change reviews was not maintained as specified in Technical Specification (TS) 6.5.3.2.a.

The inspector reviewed and discussed the IPAT findings and the applicable station procedures with PSE&G to determine if the second review for procedure changes was independent. This review determined that an independent SQR technical review had not been maintained in all instances. For example, a January 9, 1990, change to procedure SP(O)4.0.5-P-RH-12, "Inservice Testing - RHR," did not receive an independent review. The failure to perform independent reviews is considered to be another example of a violation of TS Section 6.5.3.2.a, and of 10CFR50.59 as discussed in section 4.3.1.A of this report (VIO 50-272 and 50-311/90-22-02).

Discussions with the licensee indicated that their review confirmed that an independent SQR technical review had not been maintained for certain reviews. After the IPAT inspection, PSE&G issued additional guidance to station personnel to re-emphasize the importance of assuring that an independent SQR technical review was performed as required by TSs.

On November 1, 1990, PSE&G is scheduled to begin implementation of station procedures that will apply to both facilities. AP-32, "Implementing Procedures Program," will be replaced with a new procedure NC.NA-AP-ZZ-32 (NA-AP-32)," Preparation, Review and Approval of Procedures. The inspector reviewed the current guidance for station personnel and the new procedure NA-AP-32 to ensure that PSE&G adequately addressed the concern. As an interim measure until the new procedure is issued, a memorandum was issued to station personnel which described the methodology to be used to ensure that an independent technical review is maintained. Based on the above corrective action, the inspector considered the unresolved item and the violation closed.

C. Misapplication of 10CFR50.59

(Open) Unresolved Item 50-272 and 311/90-81-23: The NRC identified examples of misapplication of 10CFR50.59 requirements. For example, a 10CFR50.59 safety evaluation was used to justify the installation of a non-code repair. In another case, a required 10CFR50.59 safety evaluation was not performed when an eroded containment fan coil unit was repaired through the use of Belzona "R" metal. Additionally, station management displayed an unfamiliarity with 10CFR50.59 requirements, and Administrative Procedure AP-32, "Implementing Procedures Program," contained erroneous information with respect to 10CFR50.59.

To assess the licensee 10CFR50.59 safety evaluation process, a review of the applicable procedures was performed. Presently, Salem Generating Station Administrative Procedure (AP) 32, Revision 4, "Implementing Procedure Program"' and DE-AP-ZZ-008, "10CFR50.59 Reviews and Safety Evaluations" are the two procedures that govern procedure changes. AP-32 has been revised since the IPAT inspection and now refers to DE-AP-ZZ-008 for guidance on performing safety evaluations. By November 1, 1990, AP-32 will undergo a major revision. That revised procedure (No. NA-AP-ZZ-32), along with NC.NA-AP-ZZ-0059 (NA-AP-59) "10CFR50.59 Reviews and Safety Evaluations," will govern the process associated with implementing procedures and 10CFR50.59 safety evaluations, replacing AP-32 and DE-AP-ZZ-008.

One of the significant changes in the PSE&G program has been to eliminate the use of the Significant Safety Issue screening processing. A 10CFR50.59 applicability screening process will be used. This approach will involve answering the following three questions:

-- Does this make changes to the facility as described in the Safety Analysis Report (SAR)?

-- Does this make changes to procedures as described in the SAR?

-- Does this result in the conduct of tests or experiments <u>not</u> described in the SAR?

If the screening process, which includes a second independent reviewer, concludes that all three questions can be answered no, the facility or procedure change may be issued for use. If any of the answers to the three questions is yes, a safety evaluation as currently defined in DE-AP-ZZ-008 must be performed. Although this process conforms with 10CFR50.59 as noted below, the inspector questioned the licensee's philosophy of answering the above three questions. All completed safety evaluations are required to be reviewed by the Station Operations Review Committee (SORC) prior to issuance of the procedure.

With respect to plant modifications, the same logic as described above is applied, however, all modification packages, regardless of its 10CFR50.59 applicability, must go to SORC prior to implementation. Specific to temporary modifications (T-MODs), the same screening process is also applied, along with a second independent review.

The inspector reviewed and discussed the IPAT findings and applicable station procedures with the licensee to determine if misapplication of 10CFR50.59 requirements occurred. For the 10CFR50.59 safety evaluation used to justify the installation of a non-code repair and in another case, for an eroded containment fan coil unit repaired through the use of Belzona "R" metal, the inspector determined that a misapplication of the safety evaluation process had occurred. The failure to perform a proper safety evaluation is a violation of 10CFR part 50.59 requirements and another example of a previous violation (Section 4.3.1.A) (VIO 50-272 and 50-311/90-22-02).

On June 15, 1990, the NRC issued Generic Letter 90-05 that addressed non-code repairs. Based on this guidance, the inspector determined that the appropriate people in PSE&G understand the requirement of how to perform non-code repairs. Additionally, the inspector reviewed the applicable station procedures that were in effect at the time of the IPAT inspection. The inspector determined that Attachment 6 of AP-32, contained conflicting guidance with respect to 10CFR50.59 and DE-AP-ZZ-008. Subsequent to the IPAT inspection, AP-32 has been revised by the removal of Attachment 6, the inspectors considered the issue to be resolved.

The inspector determined that the licensee's process to comply with 10CFR50.59 is adequate. However, for PSE&G to implement the process correctly, all employees involved with safety evaluations must understand how to interpret and answer the questions correctly.

The inspector reviewed and discussed the examples stated in IPAT with PSE&G management and engineering personnel. From these discussions, the inspector found that the licensee approach and philosophy on how to answer the screening question was not as conservative (i.e. too narrow in scope) as it should be. Thus, it allowed/and would allow certain activities to occur at the facility without a safety evaluation and the associated SORC review being performed. The licensee allows the reviewer to answer the questions in the negative if in his view the safety evaluation concludes that no unreviewed safety question exists, whether or not a change to the SAR was made. The conceptual difference is being referred to regional management for possible further discussions, if warranted. This item remains unresolved.

D. Misapplication of Safety Significant Issue (SSI)

(Closed) Unresolved Item (50-272 and 311/90-81-17), Misapplication of significant safety issues as specified in TS 6.5.1.6.a.

A review of the applicable procedures was performed. Presently, Salem Generation Station Administrative Procedures (AP) 32 and DE-AP.ZZ-008, "10CFR50.59 Reviews and Safety Evaluations," are the two procedures that govern procedure changes. AP-32 has been revised since the IPAT inspection. Procedures NC.NA-AP-ZZ-0032 (NA-AP-32)," Preparation, Review and Approval of Procedures," and NC.NA-AP-ZZ-0059 (NA-AP-59) "10CFR50.59 Reviews and Safety Evaluations," are to be implemented on November 1, 1990, and will govern the processes associated with implementing procedures and 10 CFR 50.59 safety evaluations replacing AP-32 and DE-AP-008. One of the significant changes in the PSE&G program has been to eliminate the use of the Safety Significant Issue screening process and to substitute a 10CFR50.59 applicability screening process.

The inspector reviewed and discussed the IPAT findings with PSE&G to determine if misapplication of the safety significant issue (SSI) process occurred. The inspector determined instances where procedure changes involving safety significant issues were implemented through the SQR process instead of receiving SORC review and approval, as specified in TS 6.5.1.6.a. For example, procedure OP-ST.SJ-0013(Q) was revised on May 20, 1990, to include additional acceptance criteria and no SSI determination was made. The failure to perform a SSI determination in accordance with these Technical Specifications 6.5.1.6a is considered a violation of 10 CFR part 50.59 requirements and another example of the previous violation as discussed in section 4.3.1.A (50-272 and 50-311/90-22-02).

However, based on the review of the new program which eliminated the use of SSI determination as a screening factor, the inspector considered the issue resolved and closed.

E. Personnel Errors and Communications

During the period several personnel errors occurred. Poor communications between departments and within departments was also noted on several occasions. Examples included failure to follow testing and administrative procedures by Operations, poor judgement by Operations in assessing equipment operability, and poor communications exhibited by Maintenance during review of equipment testing abnormalities. The licensee adequately addressed each of these issues and their effectiveness will be monitored in future inspections.

F. Management Involvement

Salem management was noted as being aggressively involved in safe operation of the facility as demonstrated by the recent initiation of a Daily Management Summary Report. This report is discussed daily at the 9:30 a.m. management meeting. Items addressed in this report (and at the meeting) included unit status and schedules, open issues, and selected projects status. This appears to be an effective mechanism to assure management's continued involvement.

8.3 Hope Creek

A. Personnel Errors

Two personnel errors were identified by the licensee. One was caused by a maintenance technician during surveillance testing that resulted in an isolation of the reactor core isolation cooling system. The other was caused by a senior reactor operator that resulted in a missed re-baseline of a service water spray wash pump as required by ASME Section XI. The licensee was aggressive in identification of the errors, and in corrective actions.

B. Management Involvement

Hope Creek management was noted as being aggressively involved in safe operation of the facility as demonstrated by aggressive pursuit for the causes of and the corrective actions for a higher than normal unidentified drywell leak rate, and for a small fuel pin hole leak. However, weaknesses were identified with the completeness of the technical information and the related safety basis for the safety auxiliary cooling system waiver of compliance.

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

9.1 LERs and Reports

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

Salem and Hope Creek Monthly Operating Reports for August and September 1990.

Salem LERs

Unit 1

LER 90-29 (See section 2.2.1.A of this report)

LER 90-30 (See section 2.2.1.C of this report)

Unit 2

LER 90-34 (See section 4.3.1.E of this report)

LER 90-35 (See section 4.3.1.F of this report)

LER 90-36 (See section 2.2.1.B of this report)

Hope Creek LERs

LER 90-12 concerns an entry into TS 3.0.3 on August 11, 1990. This event was reviewed in NRC Inspection 50-354/90-14. No inadequacies were noted relative to this LER.

LER 90-13 (See section 4.3.2.A of this report)

LER 90-14 (See section 7.3.A of this report)

LER 90-15 (See section 4.3.2.B of this report)

LER 90-16 (See section 8.1.A of this report)

9.2 Open Items

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

Site	Section	Status
Salem		
272/89-27-03	7.2.B	Open
272/89-11-03	7.2.C	Closed
272/89-11-10	7.2.C	Closed
272/311/90-81-05	2.2.1.H	Closed
272/311/90-81-11	4.3.1.A	Closed
272/311/90-81-21	4.3.1.B	Open
272/311/90-81-16	8.2.B	Closed
272/311/90-81-17	8.2.D	Closed
272/311/90-81-23	8.2.C	Open
272/311/90-22-02	2.2.1.H 8.2.B, C, D	Closed

Hope Creek

354/90-16-01	4.3.2.A	Closed
354/90-16-02	4.3.3.B	Closed

10. EXIT INTERVIEW

10.1 Resident

The inspectors met with Mr. S. LaBruna and Mr. C. P. Johnson 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 10CFR2 restrictions.

10.2 Specialist

Date(s)	Subject	Inspection Report No.	Reporting Inspector
9/25-28/90	Security	272,311/90-23 354/90-19	Dexter