U. S. NUCLEAR REGULATORY COMMISSION
REGION I

Report Nos. 50-272/90-26
50-311/90-26
50-354/90-21

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: November 13, 1990 - December 31, 1990

Inspectors: T. P. Johnson, Senior Resident Inspector
S. M. Pindale, Resident Inspector
S. T. Barr, Resident Inspector
H. K. Lathrop, Resident Inspector
H. J. Kaplan, Senior Reactor Engineer
R. A. McBrearty, Reactor Engineer
P. K. Patniak, Reactor Engineer
T. E. Walker, Senior Operations Engineer

Approved: P D Swetland 1/22/91
P. D. Swetland, Chief, Projects Section 2A — Date

Inspection Summary:
Inspection 50-272/90-26; 50-311/90-26; 50-354/90-21 on November 13, 1990 - December 31, 1990

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

Results: The inspectors identified two non-cited violations; one for Salem and one for Hope Creek. An executive summary follows.

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EXECUTIVE SUMMARY

Salem Inspection Reports 50-272/90-26; 50-311/90-26

Hope Creek Inspection Report 50-354/90-21

November 13, 1990 - December 31, 1990

OPERATIONS (Modules 60705, 60710, 71707, 71710, 71714, 93702)

Salem: The Salem units were operated in a safe manner. Service water leaks and radiation monitoring system actuations were reported, and licensee actions were appropriate. Licensee response to a service water leak onto Unit 2 auxiliary feedwater pumps was timely, deliberate, conservative, and performed in a safety conscious manner. The licensee's program to identify and correct control room instrumentation deficiencies was effective. Unit 2 achieved a "black board" condition for annunciator alarms. Control room licensed operators were proficient in operating each Salem unit even with the panel differences resulting from the human factors upgrades. Cold weather preparations were adequate; however, programmatic weaknesses associated with their implementation and documentation were identified.

Hope Creek: The unit was operated in a safe manner. The reactor automatically scrammed on November 17, 1990, caused by a moisture separator high level turbine trip. Licensee followup including root cause analysis and corrective actions were timely and thorough. Licensee followup to the resultant engineered safety features actuations when a battery charger failed during system realignment, on November 26, 1990, was adequate. Licensee response to a high pressure coolant injection system failure was appropriate. Cold weather preparations were adequate. The core spray system was properly aligned. Preparations for the third refueling outage were excellent. Open items associated with an inadvertent reactor cavity draining and with emergency operating procedures were closed. Licensee actions associated with a service water through wall leak were appropriate.

RADIOLOGICAL CONTROLS (Modules 71707, 93702)

Salem: Periodic inspector observation of station workers and Radiation Protection personnel implementation of radiological controls and protection program requirements did not identify any deficiencies. The 1R13 radiation monitor channel calibration and detector issues remain unresolved. There has been a reduction in contaminated areas.

Hope Creek: Periodic inspector observation of station workers and Radiation Protection personnel implementation of radiological controls and protection program requirements did not identify any deficiencies. A drywell inspection did not identify any abnormalities. Refueling outage preparations were excellent.

MAINTENANCE/SURVEILLANCE (Modules 61726, 62703)

Salem: Routine observations did not identify any deficiencies. The licensee identified a non-cited violation regarding incorrect surveillance frequency for the power operated relief and block valves position indication.

Hope Creek: Routine observations did not identify any deficiencies. The licensee identified a non-cited violation associated with late surveillance tests for an offgas hydrogen chemistry sample and analysis. A containment isolation occurred due to personnel error during surveillance testing.

EMERGENCY PREPAREDNESS (Module 71707, 93702)

An unusual event and a loss of the ENS phone at Hope Creek on November 26, 1990 and December 10, 1990, respectively, were appropriately classified and responded to by the licensee.

SECURITY (Module 71707, 93702)

Routine observation of protected area access and egress showed good control by the licensee. Events associated with a protected area fence intrusion and a sleeping guard were appropriately responded to by the licensee. A review of security fence modifications did not identify any deficiencies.

ENGINEERING/TECHNICAL SUPPORT (Modules 57050, 57080, 71707)

Salem: Review of the management of engineering work activities determined that they were being performed in accordance with applicable procedures and were being properly prioritized and executed. Specialist review of the service water system problems and upgrades did not identify any new concerns.

Hope Creek: Review of the management of engineering work activities determined that they were being performed in accordance with applicable procedures and were being properly prioritized and executed. Four previously identified unresolved open items were appropriately addressed and are considered closed.

SAFETY ASSESSMENT/ASSURANCE OF QUALITY (Modules 30702, 71707, 90712, 90713, 92700, 92701, 94702)

Salem: The material condition upgrade project has led to short term improvements in some plant areas. Licensee actions in response to a Unit 2 main generator hydrogen leak were aggressive and thorough.

Hope Creek: Refueling outage preparations were excellent and proactive. The licensee is re-evaluating their practice of voluntarily entering Technical Specification Action Statements to perform maintenance and testing.

DETAILS

1. SUMMARY OF OPERATIONS

1.1 Salem Units 1 and 2

Salem Units 1 and 2 began the report period operating at full power. Minor power reductions occurred during the period to perform maintenance and testing activities. Also, two Unit 2 shutdowns were initiated and later terminated when repairs were effected. For the remainder of the inspection period power operation continued for both units.

1.2 Hope Creek

The Hope Creek unit began the report period in Cold Shutdown, completing maintenance and followup activities from the November 4, 1990 automatic reactor scram. The unit was restarted on November 14, 1990, and the turbine generator was synchronized on November 15, 1990. On November 17, 1990, the unit automatically scrammed from 100% power due to a main turbine trip during valve testing. The unit was restarted on November 18, 1990. The unit remained operational until it was shutdown on December 26, 1990 to commence the third refueling outage. At the end of the period, the Hope Creek unit was in Operational Condition 5 (Refueling).

2. OPERATIONS

2.1 Inspection Activities

The inspectors verified that the facilities were operated safely and in conformance with regulatory requirements. Public Service Electric and Gas (PSE&G) Company management control was evaluated by direct observation of activities, tours of the facilities, interviews and discussions with personnel, independent verification of safety system status and Technical Specification compliance, and review of facility records. These inspection activities were conducted in accordance with NRC inspection procedures 60705, 60710, 71707, 71714, and 93702. The inspectors performed normal and back-shift inspections (449 hours), including deep back-shift inspections as follows:

Unit	Inspection Hours	Dates
Salem	3:30 a.m. - 5:00 a.m.	November 15, 1990
	11:30 a.m. - 1:30 p.m.	December 24, 1990
Hope Creek	None	

2.2 Inspection Findings and Significant Plant Events

2.2.1 Salem

A. Service Water (SW) System Leaks

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

Unit	Component/Leak	Date	Time
1	No. 12 SW header one inch leak in service water bay No. 3	11/19/90	11:30 p.m.
1	1R13D cooling water line (3/4 inch) to No. 14 CFCU radiation monitor	11/20/90	3:30 p.m.
1	No. 15 containment fan coil unit (CFCU) pinhole leak in a 3/4 inch pressure tap (weld)	11/23/90	2:20 p.m.
1	No. 14 SW header through wall leak (about 1/2 inch) in inner penetration area	11/23/90	11:15 p.m.
2	No. 2A emergency diesel generator (EDG) through wall (weld area) seepage in six inch line to EDG SW cooler	11/24/90	4:00 a.m.
1	No. 14 CFCU weld leak on outlet piping on a 3/4 inch vent line	11/28/90	2:55 a.m.
1	No. 14 CFCU pinhole leak in 3/4 inch instrument tube	11/30/90	10:00 a.m.
1	No. 14 SW pump through wall leak on a 3/4 inch gland seal line	11/30/90	10:00 p.m.
1	No. 12 CFCU through wall seepage on a 10 inch return line	12/3/90	5:30 a.m.

Unit	Component/Leak	Date	Time
1	No. 11 SW nuclear header through wall leak on four inch pipe that supplies traveling screens	12/6/90	3:20 p.m.
1	Leak at valve 12SW157 for No. 12 residual heat removal room cooler SW leak on 3/8 inch tubing at weld joint	12/7/90	3:55 p.m.
2	Leak at inlet pipe for No. 21 component cooling room cooler (see sections 2.2.1.G and 7.1.A)	12/20/90	2:42 p.m.

For each occurrence the leak was minimized or isolated, an ENS call was made and the inspector notified, an incident report was written to investigate the cause(s), and the leak was repaired. The inspector reviewed each occurrence including licensee actions. Discussions were held with licensee personnel. The inspector concluded that licensee actions were appropriate and the inspector had no further questions at this time.

B. Radiation Monitor Engineered Safety Feature (ESF) Actuations

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

Unit	Radiation Monitor	Date	Time
2	2R12B	November 13, 1990	1:43 p.m.
1	1R45	November 17, 1990	4:45 a.m.
1	1R45	November 18, 1990	4:25 p.m.
1	1R1B	November 23, 1990	11:00 a.m.
1	1R12B	December 14, 1990	11:15 a.m.
2	Unknown	December 23, 1990	9:00 p.m.
2	Unknown	December 24, 1990	11:41 a.m.

The inspector reviewed licensee actions regarding these events. The licensee intends to submit an LER for these events. No unacceptable conditions were noted.

C. Unit 2 Annunciators "Black Board" Condition

Salem Unit 2 achieved an annunciator "Black Board" condition (e.g., all alarms were extinguished) on December 9, 1990. The licensee has a program to reduce the number of out of service control room instruments and alarms. This is one indication of the success of the program. Unit 1 had three lit alarms at this time. The Unit 2 "Black Board" continued throughout the remainder of the period.

D. Licensed Operator Watchstanding During Control Room Human Factors Modifications

The licensee had previously restricted licensed operator watchstanding during phase 1 control room panel modifications. This was accomplished per Information Directive number 88-013 dated September 6, 1988. Both units completed the phase 1 upgrades in October 1989. Phase 2 upgrades continued with Unit 2 completed in June 1990. The licensee elected not to continue to restrict licensed operator watchstanding during the current phase 2 of modifications based on the following:

-- There were no control panel layout differences between units,

-- Most of the changes replaced the analog control room indicators with digital (Dixon) devices,

-- Simulator training (Unit 2) was performed prior to Unit 2 restart in June 1990, and

-- The first week of Unit 2 watchstanding was performed as the "DESK" operator.

The inspector discussed this item with licensee operators and management personnel. Since Unit 2 restart in June 1990, there have been no operator errors due to unit panel differences. Based on inspector observations and discussions, operators appear to be proficient in standing watches on either unit. Unit 1 is scheduled for phase 2 upgrades beginning in February 1991. The inspector had no further questions at this time.

E. Cold Weather Preparations

The inspector reviewed the licensee's program which protects against extremely cold weather to determine whether the program was effectively implemented. Salem implements Operations Directive (OD) No. 71, "Station Preparations for Winter Conditions," twice a year (once in October and once in January). The procedure directs the operating shifts to determine whether specific equipment (e.g. space/room heaters, tank recirculation pumps and heat exchangers, heat trace panels) is operable and capable of protecting important plant equipment from the cold weather. Components which are found to be inoperable are to have a work request prepared to repair them.

The inspector reviewed OD-71 and the shiftly and weekly Operations logs. The inspector also conducted a plant walkdown and found that several components were inoperable and were appropriately tagged out of service (work requests written). The inspector concluded, however, that there was not sufficient procedural guidance to specify how equipment operability could be determined, such as specific steps to place heat trace equipment in service or specific setpoints for the diesel generator room heater thermostats. The thermostats were found to be set differently for the six diesel generator rooms. Additionally, the inspector found that the licensee does not maintain the completed OD-71 procedures because it is classified as non-safety related. The OD-71 is the only mechanism by which the cold weather associated work requests can be programmatically tracked. There was also no apparent mechanism to ensure that the work is completed before extreme cold weather occurs.

The above concerns were discussed with licensee personnel, who immediately implemented a new administrative requirement to maintain (microfilm) completed OD-71 procedures. The licensee also stated that the procedure would be reviewed so that improvements can be made. The inspector will closely monitor the effectiveness of the program and will review the results of the January 1991 performance of OD-71. This item is unresolved. (UNR 272/90-26-02)

F. Control Room Instrumentation

In a previous report, the inspector reviewed licensee actions regarding improving control room indications (see NRC Inspection Report 50-272/90-24; 50-311/90-24, Section 7.1.A). As a follow-up, the inspector discussed with the Salem Controls Maintenance Engineer the progress being made to reduce the number of out of service control room instruments. Salem uses the number of control room instruments out of service as a performance indicator, and the station tracks these instruments by identifying applicable work orders. The inspector reviewed Maintenance Department records and found that the total number of out of service instruments (CR&CI) has been steadily declining since August 1990. At the end of the inspection period the total number of out of service instruments was 56 for Unit 1 and 53 for Unit 2; the station goal is to maintain the total number of open CR&CI work orders less than 40 per unit. The inspector compared the Maintenance Department list of CR and CI open work orders with the Log 13 that operating crews use to identify and track out of service control room instruments. The inspector identified a small number of items in the Log 13 that did not appear on the Maintenance Department open work order list but through discussions with maintenance personnel determined the reasons for this were administrative and the items were being tracked and worked by Maintenance. The inspector examined both lists of out of service instruments and did not identify any instruments of critical safety significance and also interviewed members of different operating crews to determine their level of confidence in the manner which these instruments were tracked and repaired. The operators were satisfied with the attention station management gave to out of service instruments and the timeliness in which the instruments were repaired. The inspector concluded that Salem has an effective program for identifying and tracking out of service control room instruments and is making good progress in reducing their number.

G. Service Water Leak Affecting Both Motor Driven Auxiliary Feedwater Pumps

On December 20, 1990, two Salem health physics technicians discovered water spraying in the overhead piping in the Unit 2 Auxiliary Feedwater (AFW) pump area. A leak was determined to coming from the 1 1/2 inch service water inlet piping to the No. 21 component cooling pump room cooler. The on-shift operators stopped the leak by isolating the entire No. 21 nuclear service water header due to the location of the leak being upstream of the isolation valves for that room cooler. The licensee initially estimated that approximately 6000 gallons of water had been released in a 10-15 minute period before the leak was isolated. In that time span both motor driven AFW pump motors were sprayed by the service water and were declared inoperable, placing the plant in Technical Specification (TS) 3.7.1.2A Action Statement B which requires the plant to be in Hot Standby within six hours.

Coincidentally, the plant also entered two general TSs requiring a plant shutdown, TS 3.0.3 and 3.0.5. TS 3.0.5 was entered because the backup power supply for the No. 21 charging pump, the No. 2B diesel generator, was tagged out for maintenance and the No. 22 charging pump had to be declared inoperable due to the isolation of No. 21 nuclear service water header, which cools the pump. This TS allows two hours to correct the situation or else be in Hot Standby within the following six hours. TS 3.0.3 was entered because Salem has a pending safety evaluation which states that when a room cooler is inoperable the associated equipment is inoperable, and the isolation of the No. 21 nuclear service water header resulted in the room coolers for two containment fan coil units and a containment spray pump being declared inoperable. This TS allows one hour to start shutting down and another six hours to be in Hot Standby.

Initial steps taken by the licensee included a temporary patch over the leak and a unit shutdown initiated at 2:56 p.m. Subsequently, a blank was placed in a flange upstream of the leak, and the No. 21 nuclear service water header was returned to service. With this header operable, the plant exited TS 3.0.3 and 3.0.5 at approximately 8:40 p.m. on December 20, 1990. Prior to this, the No. 21 and No. 22 AFW pumps were meggered, test run and declared operable. All TS Action Statements were exited before a complete shutdown had been required or achieved, and the plant was returned to full power. The section of service water that had developed the leak was removed for examination (see section 7.1.A of this report), and a new section of pipe was fabricated to replace it. This new section of pipe was installed on December 26, 1990, and the No. 21 component cooling pump room cooler was resupplied with service water and declared operable.

The resident inspector was onsite at the time of the leak and responded to the AFW pump room, arriving just after the No. 21 nuclear service water header was isolated. Licensee operators, maintenance personnel, and system engineers had also arrived at the scene, and the inspector noted that the work on the piping and the restoration of the two motor driven AFW pumps was performed in an effective and deliberate manner. The inspector also observed the Salem control room staff and operations management during the evolution of the event, and observed that their management of the event and use of the TSs was conservative and safety-conscious. The licensee was prompt in the notification of the resident staff of their plans and was open in their discussion of the event and its ramifications in a telephone conference call with NRC Region I and NRR personnel conducted on the afternoon of December 20, 1990.

As a followup to the event and discussions with the NRC, the licensee conducted an inspection of all service water piping supplying room coolers. The inspection revealed no other examples of the type of corrosion attack that had occurred on the No. 21 component cooling pump room cooler piping. This inspection was conducted within two weeks of the event, with the resident inspector monitoring parts of it and noting it to be effective in determining that a similar occurrence is not imminent. All of this piping is scheduled to be replaced in the Salem Service Water Piping Replacement Plan.

H. Open Item Followup

(Closed) Unresolved Item 272 and 311/88-14-01: Compliance with Technical Specifications (TSs) concerning operability of the main steam isolation bypass valves (MS18). The inspector reviewed the associated TS and FSAR sections and interviewed Operations personnel to ascertain whether TSs are properly implemented. The inspector concluded that the existing administrative controls and TS action requirements properly implement the associated regulations and specifications. This item is closed.

2.2.2 Hope Creek

A. Automatic Reactor Scram

Sequence of Events and Licensee Actions

The Hope Creek reactor scrammed automatically from 100% power at 3:52 a.m. on November 17, 1990, during main turbine valve surveillance testing per procedure OP-ST.AC-001. The "A" moisture separator high level trip caused a turbine trip when the No. 4 combined intermediate valve was stroked. Conditions were normal and systems responded appropriately on the scram. Reactor water level was recovered by the reactor feedwater pumps, all rods inserted and the two low-low set safety relief valves opened and reset accordingly. A similar reactor scram occurred on January 6, 1990 (NRC Inspection 50-354/90-05). Causal factors for that scram included a procedure non-compliance, one of three normal drain paths isolated and inadequate instrumentation tuning of the level control system for the moisture separator.

The licensee's followup for the November 17, 1990 scram included a post scram review by Operations per procedure OP-AP.ZZ-101 and by the station operations review committee (SORC), and an independent review by a significant event review team (SERT). Exact root cause could not be immediately determined; however, SORC and SERT recommended, and station management authorized, restart contingent upon a moisture separator level control testing program at 25%, 85% and 100% reactor power.

The licensee completed post scram reviews and implemented corrective actions. The unit restarted and achieved criticality at 5:00 p.m. on November 18, 1990. The turbine generator was synchronized at 8:55 a.m. on November 19, 1990. The licensee successfully completed surveillance testing of the moisture separator level control and drain systems at 25% power and again at 85% power. The unit's power was then increased to near full power.

As reported in LER 90-28, the licensee concluded that the scram was caused by malfunction of the level control system for the "A" moisture separator. Contributing factors included sluggish operation of the emergency dump system, misoperation of the level switches, potentially leaking check valves on the normal drain line and a possible obstruction in the drain/dump paths.

Licensee corrective actions included the following:

-- Verification of all normal and emergency drain paths,

-- Monitoring of setpoints, gains, and reset rates; and recalibration and at-power tuning/testing of both normal and emergency moisture separator level control systems,

-- Satisfactory performance of the surveillance test at 25% and again at 85% reactor power,

-- Changing procedure OP-ST.AC-001 to perform valve testing $\leq$ 85% power,

-- Monitoring of system operation at 100% reactor power, and

-- Planning to inspect the moisture separator and drain paths during the upcoming (third) refueling outage.

In addition, the SERT also performed a root cause analysis and made recommendations. The SERT concluded that the scram was caused by sluggish operation of: (1) The normal drain system due to one of three valves being repacked; and (2) The emergency dump system due to the valve being either stuck shut and differences between the "A" and "B" system.

NRC Review and Conclusions

The inspector reviewed post scram plant conditions and assessed licensee actions. The inspector reviewed control room instruments and recorder traces, interviewed on-shift operators and management personnel, reviewed emergency procedure implementation and reviewed the post scram review checklist (OP-AP.ZZ-101). The inspector noted that licensee plant and operations management had responded to the site for scram followup (Saturday morning). The inspector also reviewed the SERT report, including the root cause analysis and recommendations, and LER 90-28. The inspector concluded that the line management, SORC, and SERT reviews were thorough and timely.

The inspector also reviewed the moisture separator test program plan, and observed portions of the testing conducted. The inspector concluded that these tests were well planned and executed. Good coordination and involvement by instrumentation and control technicians, system engineers, operators and management personnel was noted. With regard to the January 1990 event, the inspector determined that system misalignment and operator error which contributed to that event may have masked the significance of MSR drain system tuning and/or design inadequacies which caused this event.

B. Unusual Event; Engineered Safety Features (ESF) Actuations; Reactor Power Runback

Sequence of Events and Licensee Actions

At 11:43 a.m. on November 26, 1990, the licensee declared an Unusual Event when an ESF actuation resulted in a high pressure coolant injection (HPCI) system initiation and injection into the reactor vessel. An intermediate reactor recirculation pump runback also occurred from 100% power. Upon determining that the HPCI start was spurious, injection was terminated. Plant conditions were stabilized at about 70% reactor power.

Earlier in the morning, safety related channel "A" 125VDC battery charger AD414 had been removed from service for performance of surveillance test MD-ST.PK-005(Q), "125VDC Battery Charger Service Test." The spare charger (AD413) was in service as the 125VDC "A" bus feed. At 11:19 a.m., a power surge and resultant voltage spike from the AD414 battery charger occurred as the charger was being re-energized. The power surge overloaded the input of the "A" Topaz (ECCS) inverters causing automatic isolation and resetting of the inverters on high voltage. The resultant loss of the vital 120 VAC power and the immediate reenergization caused the spurious actuation of the "A" ECCS logic, including:

a. Automatic start of the "A" emergency diesel generator (EDG) and a load shed of the non-vital 480VAC load centers on the "A" 4KV 1E bus. The EDG came up to speed and voltage, but did not close into the bus as it was still fed from its normal offsite-power supply.

b. Residual heat removal pump (RHR) "A" and core spray (CS) pump "A" started in the minimum flow recirculation mode. The "A" RHR injection valve opened when isolation valve leak depressurized one section of piping which actuated the low pressure interlock for that valve. The "A" service water pump was in standby and also started automatically.

c. The operating "A" reactor feedwater pump (RFP) lube oil pump tripped due to loss of power (fed from one of the shedded 480V load centers). This caused the "A" RFP to trip. Reactor water level decreased to the low level (Level 4) setpoint of 30 inches which resulted in an intermediate runback signal to the reactor recirculation pumps, and reactor power decreased to about 70%.

d. HPCI automatically initiated due to the spurious ECCS actuation signal. HPCI injected into the reactor vessel for about three seconds.

e. A partial primary containment isolation system (PCIS) actuation occurred, and reactor building and drywell ventilation systems tripped.

The plant responded as designed to the reactor recirculation flow intermediate runback. After determining that the ESF actuation signal was spurious, the operators terminated HPCI injection, stopped the "A" EDG, "A" RHR and "A" CS pumps and returned these systems to their normal standby configuration. The PCIS actuation and building ventilation trips were reset and returned to normal. The "A" 125VDC distribution system was also returned to normal. The "Unusual Event" was terminated at 11:44 a.m.

The spurious actuation of ECCS systems during battery charger realignment is a recurrent, but not repeatable problem at Hope Creek. The licensee had previously developed a design change package (DCP) modification to prevent recurrence. This modification will eliminate the Topaz inverters and will replace them with feeds from the class 1E static inverters. The modification is scheduled for implementation during the third refueling outage which began in late December 1990. Contrary to the original licensee 10CFR50.72 report, the licensee concluded that neither a concurrent HPCI surveillance in progress at the time of the event, nor any procedural/personnel error contributed to this event. The licensee implemented procedural enhancements to the associated operating and maintenance procedures. The reactor was returned to 100% by 5:00 p.m. on November 26, 1990.

NRC Review and Conclusions

The inspector responded to Hope Creek control room to review post-event activities. Operator response was reviewed and determined to be good, and in accordance with abnormal operating procedures. The inspector reviewed the completed incident report OP-AP.ZZ-101 and attended the associated Station Operations Review Committee meetings. Further followup included participation a conference call on November 30, 1990 between NRC and PSE&G. NRC Information Notice 90-22 regarding similar BWR events, LER 89-19 regarding a similar Hope Creek event, and LER 90-29 concerning this event were also reviewed.

The inspector discussed the event with the on-shift operators, licensee engineers and management personnel. The DCP was reviewed and the inspector confirmed its implementation was scheduled for the third refueling outage. The inspector reviewed the related electrical schematic and logic diagrams and verified that the actions that occurred were consistent with the design. The DCP to augment the Topaz inverters will apparently improve overall reliability of the ECCS power supply. Any failure of the new power supply would still cause the same plant transient. The inspector concluded that licensee followup to this event was adequate.

C. High Pressure Coolant Injection (HPCI) System Inoperable

At 3:17 p.m. on November 29, 1990, the licensee declared the HPCI system inoperable due to high vibration on the speed reducer gear box. During inservice testing, the vibration exceeded the required action range (2.88 mils verses 2.0 mils). The licensee entered Technical Specification Action Statement (TSAS) 3.5.1.C which allows HPCI to be out of service for 14 days. Redundant equipment was operable as required. The licensee performed maintenance on the HPCI speed reducer and retested the system satisfactorily. The TSAS was exited on December 1, 1990, when HPCI was declared operable. LER 90-31 was issued to discuss this event. Licensee response and followup to this occurrence was determined to be appropriate.

D. Cold Weather Preparations

In the beginning of the inspection period, after outdoor temperatures began to significantly decline, the inspector verified the licensee's cold weather preparations by inspecting the implementation of station operating procedure OP-GP.ZZ-003(Q), "Station Preparations for Winter Conditions." The purpose of this procedure is to outline the actions necessary to prevent structural and equipment damage due to freezing.

The inspector determined that the Hope Creek Operations staff performs the procedure once during the cold season, as the steps of the procedure become necessary, and the procedure is maintained in the control room as it is completed, as a reference for the shift supervisor of the operating crew. Through discussions with several shift supervisors and Operations Department staff members, the inspector concluded that the procedure was being implemented properly and that the Hope Creek operating crews were sufficiently aware of the actions required by the procedure to prevent cold weather damage. At the time of the inspection, approximately one half of the steps in the procedure had been completed, and by touring the

Hope Creek turbine, auxiliary and service water intake buildings the inspector verified that the steps had been performed properly. The inspector will continue to monitor the implementation of the procedure as the cold weather requires the performance of the remainder of the preventive measures in the procedure.

E. Inadvertent Reactor Cavity Drain Down to the Torus Room

(Closed) Unresolved Item 354/88-05-02; This issue dealt with the spillage of about 12,000 gallons of reactor cavity water onto the torus floor on March 13, 1988. The unit was shutdown and in a refueling configuration. The "A" residual heat removal (RHR) pump was running in the shutdown cooling mode of operation. While stroking the "B" RHR pump shutdown cooling suction valve for testing, about 12,000 gallons of water drained past one of the shut maintenance boundary valves and onto the torus floor through a partially disassembled valve. The licensee's investigation of the event assigned the root cause to personnel error in adjusting the limit switches on valve 1BCHV-FO47B during valve setup, whereby the valve indicated closed in the control room but was, in fact, partially open. Corrective actions included the proper adjustment of 1BCHV-FO47B's limit switches, counseling of the technician involved and a review of this incident with maintenance and operations personnel. The seriousness of the event was mitigated by prompt operator action, which was enabled by thorough training and a close awareness of plant conditions and work-in-progress. The inspector reviewed licensee incident and event reports and NRC inspection reports issued after this event to the present; no instances similar to this event were noted. The inspector concluded that the licensee's corrective actions had been adequate in preventing recurrence. This item is therefore closed.

F. Emergency Operating Procedure Verification and Validation

(Closed) IFI 354/88-200-02; Failure to perform Verification and Validation (V&V) on Emergency Operating Procedure (EOP) revisions. A team inspection conducted in 1988 identified concerns that the licensee's V&V process was not applied to EOP support procedures (300 series) or to revisions to the EOPs.

During an inspection in October 1990, the NRC reviewed a draft EOP maintenance document that included proposed controls to ensure that V&V was performed on EOP support procedures and on EOP revisions. The proposed controls did not appear to be adequate to correct the previously identified deficiencies in the V&V process. The licensee agreed to consider the inspector's concerns when implementing the EOP program.

Based on review of the approved EOP document, HC.OP-AP.ZZ-113(Q), "Emergency Operating Procedure Program Maintenance," Revision O, the inspector determined that the program controls are adequate to ensure that V&V is performed on EOP support procedures and on revisions to the EOPs. The EOP administrative document specifically requires V&V on the 300 series EOPs and provides guidance for determining that the appropriate portions of V&V will be performed on revisions to the EOPs. This item is closed.

G. Service Water System Through-Wall Leakage

On December 27, 1990, during the initial days of the third refueling outage, the licensee discovered a through-wall leak (five drops/minute) coming from a station service water "A" loop 30 inch pipe inside the reactor building. An emergency notification system (ENS) call was made.

The licensee also held discussions with the NRC staff about Generic Letter (GL) 90-05 and the use of temporary non-code repairs since the plant was in a scheduled shutdown when the flaw was detected. It was concluded that a temporary repair, in this case a clamp and rubber gasket, to stop the leakage constituted a non-code repair.

The licensee performed an engineering flaw evaluation to verify the structural integrity and operability of the piping. The flaw was determined to be acceptable using the guidance provided in GL 90-05. The licensee initially installed a funnel catch basin under the leakage location until a piece of replacement piping could be obtained instead of seeking written relief by the NRC to install the clamp and rubber gasket. However, because of the length of time required to design and fabricate the new piping (not available until at least January 18, 1991), the licensee determined that written relief for the temporary repair should be obtained from the NRC. The leak will be repaired prior to plant restart. NRC licensing subsequently determined that for this particular case, because the plant was shut down and repairs would be completed prior to startup, and because the licensee had determined that service water was operable for supplying its shutdown safety function, no relief would be processed for this repair.

2.3 Hope Creek Engineered Safety Feature (ESF) System Walkdown

2.3.1 Inspection Activity

The inspectors independently verified the operability of selected ESF systems by performing a walkdown of accessible portions of the system to confirm that system lineup procedures match plant drawings and the as-built configuration. The ESF system walkdown was also conducted to identify equipment conditions that might degrade performance, to determine that instrumentation is calibrated and functioning, and to verify that valves are properly positioned and locked as appropriate. This inspection was conducted in accordance with NRC inspection procedure 71710.

2.3.2 Inspection Findings

The inspector performed an ESF walkdown of the accessible portions of the core spray (CS) system. At the time of the inspection, the CS system was operable in the standby configuration per Technical Specification (TS) 3.5.1.a. As part of this inspection, the inspector reviewed applicable CS piping and instrumentation diagrams (P&ID), system operating procedures, and surveillance and inservice testing procedures for adequacy and accuracy. Several minor discrepancies were noted between the P&ID and the computer generated (TRIS) valve lineup sheets. For example, TRIS indicated a number of valves as locked closed while the P&ID did not reflect the locked condition, although valve position was consistent with the TRIS. The licensee explained that a number of valves in addition to valves required to be locked by TS were administratively locked and controlled per the licensee's equipment control procedure OP-AP.ZZ-0109(Q).

The inspector noted that the TRIS printout and the P&ID both correctly identify the TS locked valves. The inspector also noted that the two injection testable check valves, HV-FOO6A and HV-F006B shown closed on the P&ID were not referenced on the TRIS printout. These two valves have remote position indication in the control room. The licensee was investigating these apparent discrepancies when the inspection period ended.

To assess the operability of the core spray system, the inspector toured the control room to status the control panels and the core spray pump rooms in the reactor building to examine valve positioning and material condition. No significant deficiencies in either the system line-up or physical condition were noted. Housekeeping in all four pump rooms appeared adequate. In summary, the inspector concluded that the core spray system was operable and capable of performing its design function.

2.4 Hope Creek Third Refueling-Outage Preparations

The third Hope Creek refueling outage began December 26, 1990. The inspector reviewed licensee procedures, plans, schedules, outage goals, design change packages (DCPs), maintenance work items, spare parts availability, inservice inspection activities, radiation protection plans, security plans, and quality assurance and quality control (QA/QC) activities. Discussions were held with plant and outage management personnel, and the inspector attended several outage meetings.

The following procedures were reviewed:

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

The inspector concluded that the Hope Creek station and management were well prepared for the refueling outage. However, one exception was the availability of spare parts for several DCPs (see NRC Inspection 50-354/90-24). Aggressive outage goals and thorough QA/QC inspection, surveillance, and coverage plans were developed. Workers were briefed on the outage plans, schedule and goals through General Manager meetings and by the use of an information brochure/handout.

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

A. Containment Fan Coil Unit (CFCU) Radiation Monitors

(Open) Unresolved Item 272/90-24-01; Unit 1 LER 90-36 concerns an incorrect radiation detector replaced in CFCU radiation monitor channel 1R13C on March 9, 1990. This was discovered on October 25, 1990 during channel calibration. The event is similar to LER 90-32 and as a result, unresolved item 272/90-24-01 remains open pending NRC specialist review.

B. Reduction in Contaminated Floor Space

The licensee has initiated programs to decontaminate, paint and release previously restricted areas in the auxiliary building's radiological controlled area (RCA). As of December 13, 1990, the total contaminated floor area in the RCA had reached an all time low of 5.4%. The inspector periodically toured the RCA and confirmed that many areas that were previously contaminated were now "clean" and therefore were accessible without protective clothing.

3.2.2 Hope Creek

A. Drywell Inspection

Prior to reactor restart, the inspector conducted a tour and inspection of the Hope Creek drywell on November 13, 1990. Equipment, housekeeping and radiological conditions were determined to be good. The inspector interviewed the radiation protection control point and roving watch personnel, and the workers in the drywell. No unacceptable conditions were noted.

B. Refueling Outage Preparations

The inspector reviewed the radiological controls preparations for the Hope Creek third refueling outage that started December 26, 1990. Items reviewed included ALARA goals, radiation work permit planning, use of mockups and training, staffing, and access control. Specialist inspector reviews were performed during NRC Inspections 50-354/90-20 and 90-22. The inspector concluded that refueling outage preparations were excellent.

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	Service water system leak repairs
Hope Creek	Troubleshooting Plan	Moisture separator drain controls
Hope Creek	Troubleshooting Plan	"C" main steam line radiation monitor

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

4.2 Surveillance Testing Inspection Activity

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

The following surveillance test(s) was/were reviewed, with portions witnessed by the inspector:

Unit	Procedure No.	Test
Salem 2	SP(O)4.1.2.5.A	Borated Water Sources
Hope Creek	OP-ST.AC-001(Q)	Main Turbine Valve Testing

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. Incorrect Surveillance Frequency

Unit 1 LER 90-35 describes a licensee identified incorrect surveillance frequency for pressurizer power operated relief valve (PORV) and associated block valve position indication. Technical Specification (TS) Table 4.3-11, items 12 and 13, require a quarterly functional test. However, the licensee was performing the test every refueling (18 months). This discrepancy was discovered during the current ongoing TS audit. Root cause was attributed to inadequate TS amendment implementation in 1981. Licensee corrective actions included declaring the channels inoperable, successful completion of the test, and modification to the frequency of this recurring task.

This licensee identified violation is not being cited because the criteria specified in section V.G. of the Enforcement Policy were satisfied (NON 50-272/90-26-01). A continuing audit of the TS surveillance program implementation is in process in response to previously identified similar deficiencies.

4.3.2 Hope Creek

A. Late Completion of Surveillance Tests

The licensee reported two instances where a required chemistry analysis for hydrogen in an offgas sample was late due to personnel errors. With the hydrogen monitor out of service, Technical Specification 3.3.7.11.1 requires each four hour periodic sample of hydrogen offgas to be analyzed in the next four hours. The first instance was a sample taken at 4:45 a.m. that was not analyzed until 9:30 a.m. on November 16, 1990, due to oversight by a chemistry technician. A second instance occurred on November 28, 1990, at 3:27 p.m. when it was recognized that the four hour sample due at 1:27 p.m. was missed due to oversight by a nuclear shift supervisor (NSS). Licensee corrective actions included a satisfactory analysis of the samples, counseling and discipline of the technician and NSS, and a review of the events with the chemistry and operations departments. The inspector reviewed the LERs, discussed them with licensee personnel, and had no further questions at this time.

These licensee identified violations are not being cited because the criteria specified in Section V.G. of the Enforcement Policy were satisfied (NON 354/90-21-01).

B. Primary Containment Isolation System (PCIS) Actuation

On December 11, 1990, a channel "B" PCIS occurred during performance of two I&C surveillance tests (ST) simultaneously. The two surveillances tested the nuclear steam supply shutoff system and PCIS. The STs should not have been done at the same time. The reactor building ventilation systems isolated and the filtration recirculation ventilation system automatically started. Two PCIS valves for the equipment and floor drain sumps closed. The licensee terminated the testing, reset the signal and returned the systems to normal. An ENS call was made and the inspector was informed. Root cause and corrective actions will be reviewed when the licensee completes their review and submits the LER for this event.

5. EMERGENCY PREPAREDNESS

5.1 Inspection Activity

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

5.2 Inspection Findings

A. Hope Creek Unusual Event

An Unusual Event was declared at Hope Creek on November 26, 1990 (see section 2.2.2.B) due to an emergency core cooling system injection into the reactor vessel. The inspector verified that the declaration was in accordance with emergency classification guides. No unacceptable conditions were identified relative to this declaration, reporting and subsequent termination.

B. Hope Creek Emergency Notification System (ENS) Phone

On December 10, 1990, the ENS phone was found to be not functioning properly during periodic testing. The licensee notified the headquarters duty officer and the resident inspector. Communications were established on the backup phone line. The ENS phone was returned to service later in the day. Licensee actions were appropriate.

6. SECURITY

6.1 Inspection Activity

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

6.2 Inspection Findings

A. Protected Area (PA) Fence Alarm

At about 10:00 p.m. on Saturday December 8, 1990, a Delaware River boater entered the isolation zone near the Salem gatehouse. The PA alarms were responded to by security and the individual was detained. The boater was apparently lost and had docked his boat and was looking for assistance. Security and first aid personnel responded to this individual's needs. The licensee evaluated this as a non-threat and determined the event to be not reportable. A logable event entry was made and plant Incident Report was initiated. The inspector learned of the event on December 10, 1990. The inspector reviewed the reports, discussed the event with licensee personnel and regional security specialist. The inspector also reviewed security event report requirements. The inspector had no further questions at this time.

B. Security Modifications

In preparation for a new warehouse, the licensee is modifying the Hope Creek protected area (PA). The inspector verified that PA compensatory measures were appropriate; and, that guards and alarm station personnel were knowledgeable regarding these measures and modifications.

C. Security Guard Found Sleeping While on Watch

At 3:20 a.m. on November 18, 1990, a security guard was found sleeping while posted as a compensatory measure. An ENS call was made. Immediate compensatory measures were taken upon discovery and the guard was relieved. The licensee concluded that the level of plant safety was not degraded and camera surveillance of the area had been continuous. The inspector reviewed the event and discussed it with licensee security management personnel. Safeguards Event Report 90-S02 was also reviewed. The inspector had no further questions at this time.

7. ENGINEERING/TECHNICAL SUPPORT

7.1 Salem

A. Salem Service Water Leaks

On December 20, 1990, a through-wall leak was identified in Unit 2 in the 1 1/2 inch diameter, schedule 40, cement lined carbon steel inlet piping to the No. 21 component cooling pump room cooler. To stop the leak, the No. 21 nuclear service water header was isolated. (See section 2.2.1.G)

Service water system problems were first identified in 1980 and have recurred periodically since that time. In response to the problems, the licensee has replaced some affected piping with stainless steel. Similar problems developed in the initial replacement piping and in 1987 the licensee developed and presented to NRC a seven year plan to deal with service water problems.

Preliminary licensee inspections related to the newest leak indicated that the current failure is unlike previous leaks in that it appears to be mostly corrosion from the outside surface. At the location of the leak, a portion of the cement liner was found to be missing, although the inner diameter surface appeared to be in relatively good condition and the outer diameter surface was observed to be in extremely poor condition. The reason for the missing cement lining was not readily apparent.

Licensee actions included the following:

1. The failed section of pipe was removed from the system, and was sent to the licensee's metallurgical laboratory for analysis to identify the failure mechanism.

2. The removal of insulation from adjacent piping to permit visual inspection of the piping.

3. Insulation was removed from additional room cooler piping to determine, by periodic visual inspection, whether the problem is more widespread. Inspections completed by the end of the report did not identify any similar occurrences.

4. Additional small bore piping (two inches or smaller) is being evaluated to determine whether a similar periodic inspection program is necessary.

According to the licensee's seven year plan the failed line was to be replaced with piping of a different material during the next scheduled Unit 2 refueling outage in October 1991. Unless the current visual inspections show otherwise, the broken section will be replaced in kind at this time, and the seven year plan will be adhered to.

The licensee has concluded that the subject piping is original construction. The licensee's inspection program was recently established in accordance with Generic Letter 89-13 requirements, however, the initial scope of that program was limited to large bore piping greater than two inches). The program provides for increasing the scope and frequency of inspections due to plant experiences and completed inspection results. As discussed above, the licensee is evaluating whether small bore piping should be included in the inspection program. The inspector had no further questions at this time.

7.2 Hope Creek

A. Feedwater Flow Calculation Errors

(Closed) Violation 354/88-24-02; The licensee identified an error in the reactor feedwater flow calculation used for core thermal power determination. Licensee Event Report (LER) 88-24 reported this deficiency. The licensee responded to the violation in a letter dated January 13, 1989. The licensee determined root cause to be personnel error. The feedwater flow transmitters 1PDT-N002 "A" and "B" were incorrectly established using calculations that were not compensated for pressure compression as required by vendor information. Corrective actions included immediately reducing reactor power to 98%, validating all engineering data used for core thermal power, evaluating calibration requirements, confirming instrumentation accuracies, assuring that power calculation error limits established by the transient analysis were not exceeded, and performing an independent verification that there were no adverse impacts on the acceptance criteria of the power ascension test program.

The inspector reviewed the licensee's response, the LER, verified corrective actions and discussed this item with licensee personnel. This violation is considered closed.

B. Invalid Safety Parameter Display System (SPDS) Indications

(Closed) Unresolved Item 354/88-24-03; This issue dealt with an inadequately implemented design change package (DCP) for installation of the SPDS. Drywell temperature inputs were shifted from the control room information and display system (CRIDS) computer to the new SPDS computer. Inaccurately low default temperature data was apparently input to the temperature averaging network for the disconnected inputs while shifting to the SPDS computer.

During the licensee's investigation of this incident, it was discovered that all 24 of the inputs used to determine the drywell average air temperature had been disconnected for 15 hours on June 20, 1988. The drywell average temperature measurement is used daily to verify compliance with the drywell temperature Technical Specification (TS) section 3.6.1.7, which requires that at least one input from each elevation zone be available for the calculation to be valid. Based on past listing of drywell average temperatures and the readouts from the four drywell temperature accident monitoring instruments in the control room, the licensee concluded that the TS drywell temperature limit of 135 degrees F had not been exceeded.

Corrective actions included having each department associated with the SPDS identify each SPDS computer point utilized for TS acceptance criteria during the implementation of the DCP and verify its accuracy. Seventeen such points were identified and verified to have been accurate. Additionally, the licensee revised procedure OP-DL.ZZ-026(Q), "Surveillance Log", to verify that at least one input for each drywell elevation zone was operable and provided an alternate means to measure the drywell average temperature if the SPDS computer was out of service. The inspector concluded that these actions appeared adequate. This unresolved item is considered closed.

C. Core Spray Motors B and D Seismic Evaluation

(Closed) Unresolved Item 354/88-80-02; Substantiation of Design and Seismic Capability of Weight Arrangements on Core Spray Motors. The licensee performed an engineering evaluation (H1-BE-NEE-0506) to assess the potential safety impact of the additions of a vibration damper and absorber on core spray motors. This was previously evaluated as an acceptable condition in 1985 by General Electric during Hope Creek startup. However, the engineering basis and resultant documentation were unavailable.

The licensee concluded that both the damper and the absorber are able to effectively reduce the core spray pump vibration to one mil peak-to-peak displacement (from 3.5 mils to 1.7 mils). The addition of the damper or the absorber has no adverse effect on motor performance, and both designs are acceptable for permanent plant use. Both the damper and the absorber are structurally adequate to withstand the seismic load during a safe shutdown earthquake event. No safety-related equipment will be jeopardized, and there is no adverse effect on safety and reliability.

The inspector reviewed the engineering evaluation and discussed the item with licensee personnel. The licensee's evaluation and supporting data received in mid-December, 1990, was transmitted to NRC Region I for further review. The inspector had no further questions at this time and this item is closed.

D. Verification of Instrument Calibration Data (ICD) Cards

(Closed) Unresolved Item 354/87-17-02; On July 29, 1987, the licensee declared an Unusual Event and commenced a plant shutdown after determining that the filtration, recirculation and ventilation (FRVS) flow transmitters were calibrated using incorrect calibration data. The root cause was determined to be a contractor-generated ICD card which had been inadequately reviewed and substituted for the correct data which had been determined during the startup test program. The licensee committed to a number of corrective actions, among which were the verification of accuracy of all safety related ICD cards which had not already been verified and a review of all safety-related ICD card calculations which had been altered subsequent to the startup test program. The licensee completed the verification of the outstanding ICD cards in July, 1989 and the review of altered ICD cards in December 1989. The inspector reviewed the documentation associated with the licensee's actions and determined that the licensee had adequately addressed their commitments. A review of incident reports and licensee event reports generated since the completion of these corrective measures did not indicate problems where ICD cards were noted as root causes. This item is considered resolved and therefore closed.

8. SAFETY ASSESSMENT/QUALITY VERIFICATION

8.1 Salem

A. Material Condition Upgrade

The licensee has instituted a program to improve the Salem material condition. A task force has been evaluating plant areas for housekeeping, lighting, insulation, painting, and equipment conditions. Detailed evaluation sheets are used and a numerical "grade" is established. These ratings are then tracked and specific improvements for the specific plant area are initiated.

The inspector reviewed the program, including the rating system. The inspector discussed program implementation with the project team and management personnel. Improvements have been noted in some plant areas including the steam driven auxiliary feedwater pump room and the 78 foot level of the auxiliary building for both units.

B. Unit 2 Main Generator Hydrogen Leak

Over a period of several days in early November 1990, Operations personnel noted an increase in the number of times necessary to add hydrogen to the main generator cooling system to maintain hydrogen pressure at 75 psig. The leakage was calculated to be about 3900 cubic feet per day as compared to a design value of 600 cubic feet per day. After consulting with the vendor, licensee management elected to reduce unit power to 50% on November 14, 1990. Hydrogen pressure was also reduced to minimize leakage.

The inspector observed the licensee's activities and noted that the response by the Maintenance, Operations, and Engineering organizations was aggressive and thorough. Ventilation in the area where the leaks were identified was enhanced via portable equipment, a hydrogen leakage monitoring program was implemented, and the leaks were identified. The leaks were primarily from instrument penetration areas on the underside of the main generator.

Although some leak repairs were accomplished a hydrogen leak remained at a thermocouple penetration and could not be stopped which was calculated to be about 2000 cubic feet per day. Full power operation was subsequently resumed on November 15, 1990. At the end of this inspection period, the enhanced ventilation equipment remained in service to prevent hydrogen buildup, and the hydrogen concentration measurement continued. The inspector concluded that the licensee's corrective and compensatory actions were good and had no further questions at this time.

8.2 Hope Creek

A. Refueling Outage Preparations

As discussed in sections 2.4 and 3.2.2.B of this report, the inspector concluded that licensee preparations for the third Hope Creek refueling outage were excellent. This includes preparations by the outage group and other station organizations. The only exception is the unavailability of spare parts for some maintenance and design change work.

B. Voluntary Entry in Technical Specification Action Statements (TSAS)

At 3:35 a.m. on December 17, 1990, the licensee removed the "B" and "D" loops of the Residual Heat Removal (RHR) system from service to conduct local leak rate testing (LLRT). This placed the licensee in a 72 hour TSAS. The inspector noted this during the morning tour of the control room on December 17, 1990. The inspector questioned the licensee's practice of voluntarily entering a TSAS to perform outage related maintenance/testing activities. The inspector stated that it was NRC practice to allow voluntary entry into TSAS as long as a net safety benefit can be realized. (The outage began December 26, 1990). The inspector reviewed administrative procedures NAP-9 and 55. There was no such guidance for this area. In this case, the only apparent benefit was to perform an outage related activity prior to the outage. The "B" and "D" loops of RHR were returned to service on December 18, 1990. The licensee reassessed their position and decided not to remove the redundant RHR loops ("A" and "C") from service scheduled for later in the week. The licensee also agreed to review their NAPs for voluntary TSAS entries.

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

9.1 LERs and Reports

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

Salem and Hope Creek Monthly Operating Reports for November 1990. No unacceptable conditions were noted.

Salem LERs

Unit 1

LER 90-26, Revisions 2 and 3 concern service water and main steam through wall leaks in ASME Class 3 systems. These events were reported to the NRC via the ENS with a one hour call. Also, the NRC reviewed these events in NRC Inspections 50-272 and 311/90-19,90-20, 90-22, and 90-24. The licensee attributed root cause to equipment erosion and corrosion. The inspector discussed this LER and the service water leaks with licensee personnel (also see sections 2.2.1.A and G, and 7.1.B)

LER 90-34, Revision 1 concerns containment ventilation isolations caused by radiation monitoring system (RMS) spikes on the 1R11A. Technician maintenance performed on September 28, 1990 resulted in a broken shield wire and this resulted in a loss of electronic filtering capability. This electrical noise caused the RMS spikes and resultant isolations. Licensee corrective actions included repair of the 1R11A wire, return to service for the RMS channel, review of the event with maintenance personnel and inclusion of poor maintenance practices associated with wire soldering into training programs. The inspector reviewed this event in NRC Inspection 50-272/90-24, and reviewed the LER including corrective actions. The inspector had no further questions at this time.

LER 90-35 (See section 4.3.1.A)

LER 90-36 (See section 3.2.1.A)

LER 90-37 (See section 2.2.1.B)

LER 90-38 (See section 2.2.1.B)

Unit 2

LER 90-40 concerns a containment ventilation isolation caused by radiation monitors 2R41C and 2R12B on October 29, October 30 and November 13, 1990. These events were reviewed in NRC Inspection 50-311/90-24. The licensee has attributed root cause to equipment design and aging concerns. No unacceptable conditions were noted relative to this LER.

Hope Creek LERs

LER 90-23 concerns an automatic start of the "E" Filtration, Recirculation and Ventilation System (FRVS) fan due to a spurious start signal. This is the fourth such incident since 1987 (see LERs 87-016, 87-033 and 90-006). Licensee corrective actions in LER 90-006 included an engineering evaluation of the spurious start signals. The evaluation described the cause of the recurrence to a less than adequate design of the "E" and "F" FRVS fan auto-initiation circuit whereby even a momentary flow perturbation would be enough to start the "E" or "F" FRVS fan. The licensee committed to submitting a design change request to install a time-delay into the auto-initiation logic to preclude spurious initiations due to momentary flow instabilities. The inspector determined that the licensee's corrective actions appeared appropriate and commensurate with the system's safety significance; the design change and its effectiveness will be assessed when implemented.

LER 90-24 concerns an unplanned reactor scram from 100% power caused by a main steam isolation valve (MSIV) closure on November 4, 1990. The event was reviewed in NRC Inspection 50-354/90-20. There were no inadequacies relative to this LER.

LER 90-25 concerns a reactor recirculation instrument line weld leak discovered on November 4, 1990 (see NRC Inspection 354/90-20). The licensee replaced the line and sent the failed weld to a laboratory for failure analysis. The preliminary analysis concluded the leak was caused by vibration induced fatigue. The final report is outstanding and will be the subject of a supplemented LER. Additional licensee corrective actions included examinations of similar pipe welds. No further defects were identified. The licensee also implemented modifications to install additional piping supports and vibration monitoring instrumentation. No inadequacies were identified relative to this LER.

LER 90-26 concerns a high pressure coolant injection (HPCI) system inoperability due to a bent support strut during system warmup operations on November 14, 1990. This was discovered by the system engineer during a walkdown of the HPCI system made during system warmup. The root cause was determined to be design inadequacy of the HPCI pipe supports during warmup operations. The licensee declared the HPCI system inoperable, repaired the strut, initiated a design change request, revised the HPCI operating procedure and briefed operations personnel. The inspector reviewed the LER, verified corrective actions and discussed it with licensee engineers. The inspector had no further questions at this time.

LER 90-27 (See section 4.3.2.A)

LER 90-28 (See section 2.2.2.A)

LER 90-29 (See section 2.2.2.B)

LER 90-30 (See section 4.3.2.A)

LER 90-31 (See section 2.2.2.C)

<u>Safeguards Event Reports (SER)</u>

SER 90-S02 (See section 6.2.C)

9.2 Open Items

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

Site	Report Section	Status
Salem		
272&311/88-14-01	2.2.1.H	Closed
272/90-24-01	3.2.1.A	Open
Hope Creek		
354/87-17-02	7.2.D	Closed
354/88-05-02	2.2.2.E	Closed
354/88-24-02	7.2.A	Closed
354/88-24-03	7.2.B	Closed
354/88-80-02	7.2.C	Closed
354/88-200-02	2.2.2.F	Closed

10. EXIT INTERVIEWS/MEETINGS

10.1 Resident Exit Meeting

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

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

10.2 Specialist Exit Meetings

Date(s)	Subject	Inspection Report No.	Reporting Inspector
11/13-15/90	EQ/Fire Protection	272 and 311/90-27 354/90-23	Paolino
12/3-7/90	Material Control	354/90-24;272 and 311/90-28	Caphton
12/10-14/90	Radiological Controls	354/90-22	Chawaga

10.3 Management Meetings

A. Salem Management Meeting at NRC Headquarters (NRR)

The inspector attended a meeting at NRR on November 14, 1990. At that meeting the following items were discussed: licensing issues, electric power systems upgrade and radiation monitoring system problems and upgrade. NRR issued a meeting summary.

B. Management Meeting to Discuss the 10CFR50.59 Process

The inspector attended a meeting in Region I on December 4, 1990, to discuss the PSE&G 10CFR50.59 process. Enclosure 1 is a list of attendees and Enclosure 2 is a copy of the licensee's handout used at the meeting.

ENCLOSURE 1

LIST OF ATTENDEES - NRC & PSE&G MEETING

DECEMBER 4, 1990

NUCLEAR REGULATORY COMMISSION

T. P. Johnson, Senior Resident Inspector
A. R. Blough, Chief, Projects Branch No. 2
P. D. Swetland, Chief, Reactor Projects Section No. 2A
L. H. Bettenhausen, Chief, Operations Branch
J. C. Stone, Salem Project Manager
S. T. Barr, Resident Inspector
S. M. Pindale, Resident Inspector
B. C. Westreich, Reactor Engineer

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

Raymond Brown, Principal Engineer, Licensing & Regulation
Michael Alpaugh, Lead Engineer, Nuclear Licensing & Regulation
J. J. Pantazes, Procedure Upgrade Project Manager
Peter Ott, Technical Engineer - NSS Salem
Charles Nentwig, Technical Engineer - Hope Creek
Scott Gillespie, Principal Safety Review Engineer
E. A. Liden, Manager - Offsite Safety Review

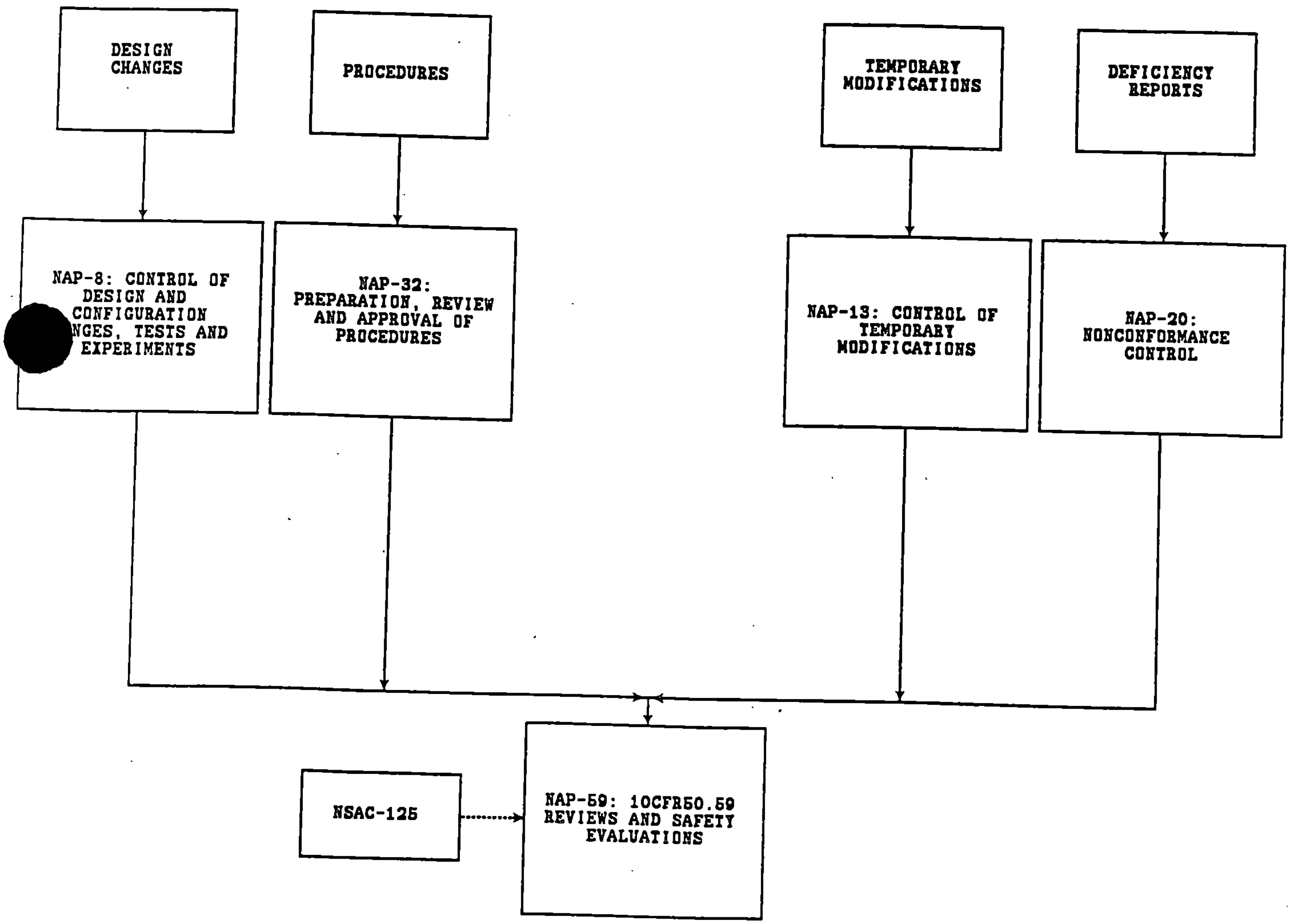
ENCLOSURE 2

PSE&G/NRC MEETING

10CFR50.59 SCREENING METHODOLOGY

DECEMBER 4, 1990

DOCUMENTS REVIEWED VS 10CFR50.59



10CFR50.59 REVIEW AND SAFETY EVALUATION PROCESS

NC.NA-AP.ZZ-0059(Q) (NAP-59)

- REPLACED E&PB PROCEDURE USED SINCE 1988
- PART OF NEW NUCLEAR DEPARTMENT PROCEDURE SYSTEM
- IMPROVES PREVIOUS PROCESS
  - FULLY INCORPORATES NSAC-125 GUIDANCE
  - PROVIDES ADDITIONAL EXAMPLES OF KEY CONCEPTS AND DEFINITIONS

10CFR50.59 REVIEW (SCREENING) PROCESS

- DETERMINES IF CHANGE, TEST OR EXPERIMENT FALLS UNDER REQUIREMENTS OF 10CFR50.59
- SCREENING CRITERIA TAKEN FROM 10CFR50.59(a)(1)
  - CHANGE TO THE FACILITY AS DESCRIBED IN THE SAR
  - CHANGE TO THE PROCEDURES AS DESCRIBED IN THE SAR
  - TEST OR EXPERIMENT NOT DESCRIBED IN THE SAR
- INCORPORATES NSAC-125 SCREENING GUIDELINES
- DOCUMENTATION OF SCREENING REVIEW REQUIRED

NAP-59 DEFINITION OF THE SAR

Safety Analysis Report (SAR) - Is the latest Salem Generating Station or the Hope Creek Generating Station Updated Final Safety Analysis Report (FSAR), including any changes thereto that have been approved via an SAR Change Notice, but not yet incorporated into the SAR by an amendment.

Documents that are included by reference in the SAR are considered part of the SAR. These include:

- Artificial Island Emergency Plan (AIEP).
- Security Plan.
- Operational Quality Assurance Program.
- Station Technical Specifications.
- Process Control Program.
- Training Program.
- Fire Protection Program.
- Environmental Qualification Program.

Also included in the SAR is the Safety Evaluation Report (SER) prepared by the NRC in support of the issuance of the station operating license, any supplements thereto, and any safety evaluations issued by the NRC in support of operating license amendments.

PSE&G LICENSING DATABASE

- FSAR/UFSAR
- SERs & SUPPLEMENTS
- TECHNICAL SPECIFICATIONS
- TECHNICAL SPECIFICATION SERs
- ENVIRONMENTAL REPORTS
- LERs
- NRC BULLETINS
- NRC GENERIC LETTERS
- NRC INFORMATION NOTICES
- 10 CFR
- CORRESPONDENCE TO NRC
- NRC INSPECTION REPORTS
- NUREG 0737 (TMI)
- NUREG 0800 (SRP)

10CFR50.59 REVIEW (SCREENING) CRITERIA

- CHANGE TO THE FACILITY AS DESCRIBED IN THE SAR
  - CHANGE TO THE DESIGN, FUNCTION OR METHOD OF PERFORMING THE FUNCTION OF A SSC DESCRIBED IN THE SAR.
    - ADDING OR DELETING AN AUTOMATIC FEATURE
    - CONVERTING AN AUTOMATIC FEATURE TO MANUAL OR VISA VERSA
    - INTRODUCING UNWANTED OR UNREVIEWED SYSTEM INTERACTION, EITHER UPON IMPLEMENTATION, AFTER AGING, OR AFTER A MALFUNCTION
    - ALTERING SEISMIC OR ENVIRONMENTAL QUALIFICATION
    - AFFECTING QUALITY GROUP CLASSIFICATION
    - AFFECTING OTHER UNIT(S)
    - NONEQUIVALENT COMPONENT REPLACEMENT

10CFR50.59 REVIEW (SCREENING) CRITERIA

- CHANGE TO THE FACILITY AS DESCRIBED IN THE SAR (CONT'D)

  - CHANGE TO THE DESIGN, FUNCTION OR METHOD OF PERFORMING THE FUNCTION OF A SSC DESCRIBED IN THE SAR. (CONT'D)

    * AFFECTING D/G LOADING SEQUENCE

    * INCREASING D/G LOAD BEYOND DESIGN CAPABILITY

    * ADDING SSCs TO THE SAR

    * OPERATION WITH KNOWN SETPOINT DRIFT OR EQUIPMENT DEGRADATION

    * CHANGES TO CALCULATIONS/EVALUATIONS THAT ESTABLISH THE DESIGN BASIS INCLUDED

  - NOT LIMITED TO SSCs SPECIFICALLY DESCRIBED IN THE SAR

  - PERMANENT AND TEMPORARY CHANGES INCLUDED

  - CHANGES MAY BE SAR TEXT, TABLES, FIGURES, OR OTHER INFORMATION RELIED UPON BY THE NRC

10CFR50.59 REVIEW (SCREENING) CRITERIA

- CHANGE TO THE PROCEDURES AS DESCRIBED IN THE SAR
  - CHANGES TO A PROCEDURE THAT IS OUTLINED, SUMMARIZED OR DESCRIBED IN THE SAR IF THE OUTLINE, SUMMARY OR DESCRIPTION IS NO LONGER CORRECT
  - NOT LIMITED TO ITEMS SPECIFICALLY IDENTIFIED AS PROCEDURES
- TEST OR EXPERIMENT NOT DESCRIBED IN THE SAR
  - TEST OR EXPERIMENTS THAT MIGHT AFFECT SAFE OPERATION OF THE PLANT BUT WERE NOT ANTICIPATED IN THE SAR.

NOTE FROM NAP-59 SECTION 6.3.1

NOTE:

Procedures are not limited to merely those items specifically identified as procedures (i.e., operations, chemistry, surveillance, etc.), but also include other procedure-type documents, such as the Emergency Plan, as well as anything described in the SAR that defines or describes activities or controls over functions, plant configuration, tasks, reviews, tests or safety review meetings.

10CFR50.59 REVIEW (SCREENING) PROCESS

- A SAFETY EVALUATION IS NOT REQUIRED IF ALL SCREENING QUESTIONS ARE ANSWERED "NO"
  - ALL ANSWERS MUST BE ADEQUATELY JUSTIFIED, INCLUDING SAR SECTIONS REVIEWED
  - IF IT IS UNCLEAR WHETHER OR NOT 10CFR50.59 APPLIES, THEN A SAFETY EVALUATION MUST BE PREPARED
- 10CFR50.59 REVIEWS MUST HAVE A PEER REVIEW AND MANAGEMENT APPROVAL
- 10CFR50.59 REVIEWS ARE RETAINED AS QA RECORDS FOR THE LIFE OF THE FACILITY
- E&PB ENGINEERING ASSURANCE REVIEW OF DESIGN CHANGE PACKAGES
- NSR WILL PERFORM AN ASSESSMENT OF 10CFR50.59 APPLICABILITY REVIEWS IN JANUARY 1991 TO EVALUATE THE IMPLEMENTATION OF THE NAP-59 PROCEDURE

10CFR50.59 SAFETY EVALUATION PROCESS

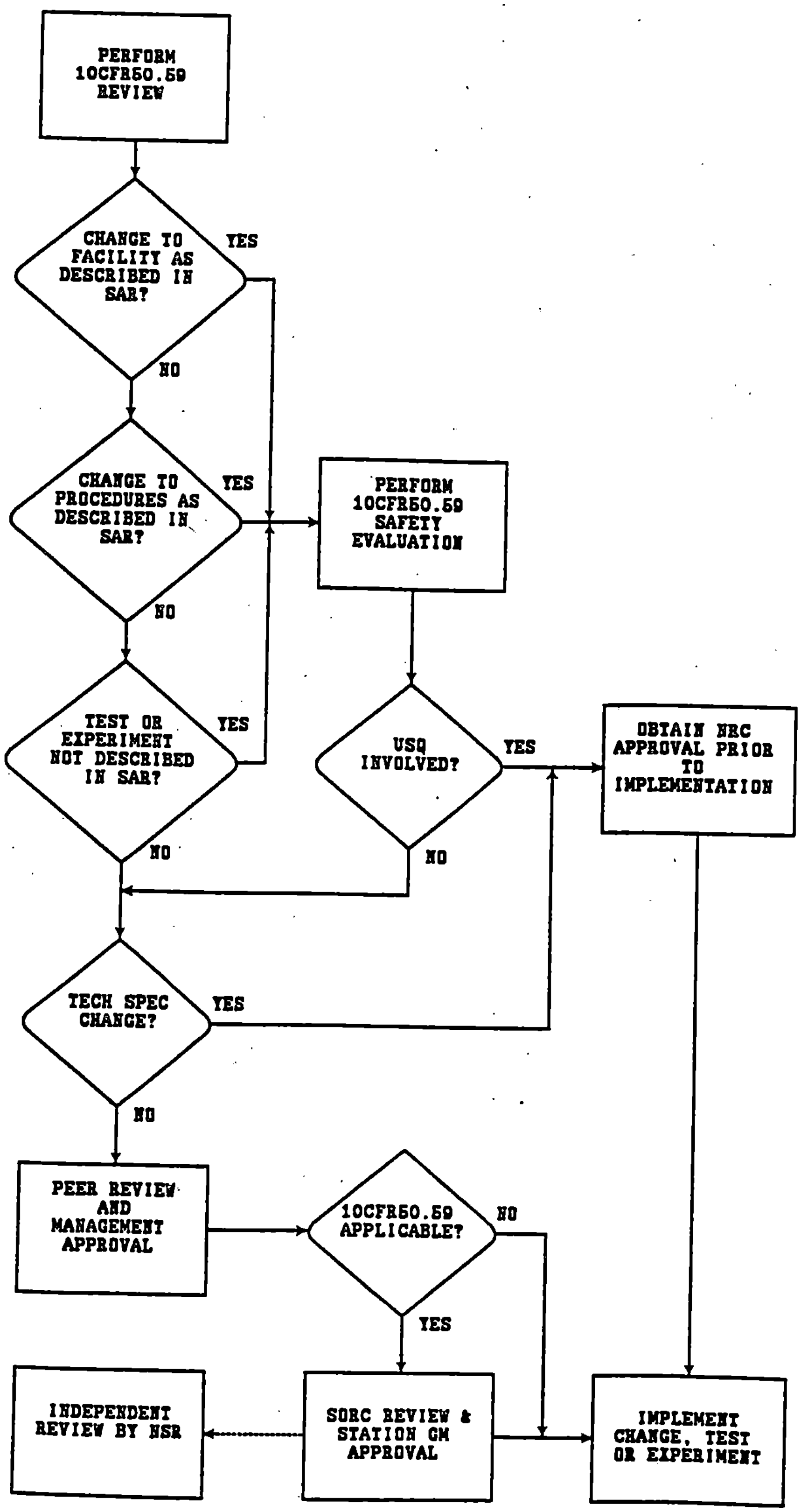
- THREE QUESTIONS FROM 10CFR50.59(a)(2) ARE ANSWERED
  - ANSWERS MUST BE JUSTIFIED ON THE FORM
  - INCLUDE SAR SECTIONS REVIEWED
- SAFETY EVALUATIONS MUST HAVE A PEER REVIEW AND MANAGEMENT APPROVAL
- SAFETY EVALUATIONS ARE REVIEWED BY SORC AND NSR
- SAFETY EVALUATIONS ARE RETAINED AS QA RECORDS FOR THE LIFE OF THE FACILITY

NOTE FROM NAP-59 SECTION 5.2.4

NOTE:

If it cannot be clearly determined whether or not 10CFR50.59 is applicable to a proposal, it shall be assumed that 10CFR50.59 is applicable and that a 10CFR50.59 safety evaluation is required.

10CFR50.59 REVIEW AND SAFETY EVALUATION PROCESS



DOCUMENTS REVIEWED VS 10CFR50.59